Business Practice Manual for Market Instruments

Version 4445

Last Revised: April 6/October 6, 2017,
### Approval History

**Approval Date:** March 27, 2009  
**Effective Date:** March 31, 2009  
**BPM Owner:** David Delparte  
**BPM Owner’s Title:** Director of Operational Readiness

### Revision History

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| 45      | 10-06-2017   | PRR 1003 includes two changes:  
2. Revisions to Attachment D and Attachment L to include possible scenarios leading to renegotiation of a default energy bid under negotiated rate option, a major maintenance adder and negotiated variable operations and maintenance (O&M) adder. |
| 44      | 04-06-2017   | PRR 971 Attachment B revision to comply with the latest GRDT and IRDT data definitions.                                                                                                                                                                                                                                                     |
| 43      | 02-02-2017   | PRR 952 Due to Aliso Canyon phase 2 gas-electric coordination initiative and the interim tariff revisions from December 1, 2016 through November 30, 2017. Effective date December 1, 2016. Miscellaneous corrections, to include updates for gas regions in Appendix C, and updates for Appendix D.                                                                                     |
| 42      | 10-07-2016   | PRR 922 ESDER 1 Changes for NGR. DA initial SOC value and option to not use energy limits or SOC in market optimization. Sections: 4.1.1, 5, 5.1.1.2.1, 5.1.1.2.2, 5.1.1.4, 8.1.1, B-Master File Update Process  
PRR 936 new reports addition due to EIM year one phase 2, Flexible Ramping Product, and Forecasting data transparency.                                                                                                                                                                                                 |
| 40      | 09-01-2016   | PRR 910 Adding Addendum to this document due to Aliso Canyon gas-electric initiative and interim tariff revisions.  
PRR 916 changes due to the bidding rule initiative.                                                                                                                                                                                                                         |
| 39      | 11-24-2015   | PRR 870 Energy bid validation rules updates section 8.2  
PRR 871 Balancing authority area GPI &EPI calculation Attachments C & M |
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<td>38</td>
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<td>PRR 852 Transition cost edits and addition of proxy cost option description. PRR 850 Updating language in sections B.2.2, C.4, D.5, G.2</td>
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<td>37</td>
<td>05-4/2015</td>
<td>PRR829 added a new section M to describe the Electricity Price Index calculation</td>
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<td>36</td>
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<td>PRR 824 added a new language due to price spike process pursuant to Tariff section 39.7.1.1.3(b)</td>
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| 35      | 12-11-2014 | PRR 809 changes CMRI to Customer Market Results Interface  
PRR 782 changes were made to MMA attachment L.  
PRR 780 changes to replace the acronym SLIC by outage management system  
PRR 753 for Changes in support of Reliability Demand Response Resource (RDRR) initiative. Changes made to sections 3.2, 5, 5.1.1, 5.1.3, 5.1.4, 5.1.5, 7.1, 8.2.1.3 and Attachment B sections B.2.2, B.2.5, and B.2.7 |
| 33      | 05-06-2014 | PRRs 703, 717, 718, changes were made for FERC order 764                                                                                      |
| 33      | 05-06-2014 | PRR 735, changes were made to Attachments G,K                                                                                               |
| 33      | 05-06-2014 | PRR 722 was a temporary process for GPI, after expiration, PRR 723 was published describing the permanent solution for GPI update            |
| 32      | 04-07-2014 | PRR 721 for FERC order 784 for posting historical one-minute and ten-minute average Area Control Error (ACE) data on OASIS.                |
| 31      | 01-06-2014 | PRR 694 for Corrections Clarifications 2013. Changes made to Sections 10.2.7 and 11.4.                                                       |
| 30      | 11-07-2013 | PRR 691 for Commitment costs refinement – major maintenance and GMC.  
PRR 689 for adding CAISO demand forecast report for seventh day out. Change made to section 12.3                                           |
| 29      | 10-02-2013 | PRR 681 to add archiving policy for CMRI reports. New section 10.4 added.                                                                     |
PRR 656 for pay for performance regulation. Changes made to sections 3.2, 6.1, 6.2, 6.3.1, 6.3.2, 10.1, 12.1, and 12.5.         |
<p>| 27      | 05-12-2013 | PRR 654 for Treatment of Market Participants with Suspended Market-Based Rate Authority. Changes made to sections 10.4 added.             |</p>
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|        |            | 5.1.1.1.4, 5.1.1.2.1, 5.1.4.1.4, 5.1.4.2.1, 6.1, 7.1, 8.2, 8.2.1.3, Appendix Attachment D section D.3, and Appendix Attachment H.  
PRR 650 for Local market power mitigation implementation phase 2. Changes made to sections 10.1, 12.1, and 12.4. |
|        | 03-12-2013 | PRR 638 for Circular Scheduling. New section 3.4.3 added.                                                                                   |
| 26     | 01-09-2013 | PRR 629 for Commitment costs refinement 2012 - Greenhouse Gas cost adder. Changes made to sections 8.2.1.3, 12.1, Appendix Attachment B section B.2, Appendix Attachment D section D.5, Appendix Attachment F example 1, Appendix Attachment G sections G.1.1, G.1.2, and G.4, and Appendix Attachment H. Added new Appendix sections: Attachment G section G.3 and Attachment K. |
| 24     | 12-10-2012 | PRR 596 for Changes to support flexible ramping settlement. Change made to section 12.1.  
PRR 598 for Regulatory Must Take - Combined Heat and Power. Changes made to sections 5.1.3.1.3 and 5.1.5.1.3, and Appendix Attachment B sections B.2.1 and B.2.2.  
PRR 609 for Data Release 3. Changes made to sections 10.2, 12.3, 12.4, and 12.7. Added new sections 10.2.6, 10.2.7 and 10.2.8. |
PRR 583 for Additional changes to support Transmission Reliability Margin functionality. Change made to section 12.2.  
PRR 587 for Changes to support non-generator resources and regulation energy management. Changes made to sections 4, 5, 5.1.1.2.1, 5.1.1.2.2, 5.1.1.4, 5.1.3.1, 5.1.4.2.1, 5.1.4.4, 5.1.5.1, 6.2, 7.1, and Appendix Attachment B sections B.2.1, B.2.2, and B.2.4. Added new section 4.1.1. |
| 22     | 06-06-2012 | PRR 549 for Changes to support Transmission Reliability Margin functionality. Changes made to section 8.2.2 and 12.2. |
PRR 545 to Remove RDRR language from BPM for Market Instruments. Changes made to sections 3.2, 5, 5.1.1, 5.1.3, 5.1.4, 5.1.5, 7.1, and Appendix Attachment B sections B.2.2, B.2.5, and B.2.7 |
<p>| 20     | 03-30-2012 | PRR 531 for changes to support local market power mitigation enhancements. Changes made to sections 2.1.1, 2.1.2, 2.2.1, |</p>
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<td>PRR 537 for Changes to support operation and maintenance cost adder review and update 2012. Changes made to sections 4.1, 8.2.1.3, and appendix Attachment B section B.2.2, appendix Attachment D sections D.5, D.5.4 and D.5.5, appendix Attachment F, and appendix Attachment G section G.1.2.</td>
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<td>PRR 520 to Clarify the CRN report definition. Change made to section 10.1</td>
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<td>PRR 486 for Changes to support generated bids and outage reporting for NRS RA resources. Changes made to sections 8.2.1.3 and B.2.3. Added new attachment I.</td>
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<td>PRR 478 for changes to support the 72 hr RUC initiative. Changes made to sections 2.1.3 and 2.1.4.</td>
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<td>PRR 481 for changes to support the grouping constraints initiative. Change made to section B.2.1. Added new section B.3.</td>
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<td>PRR 455 for Changes in support of RDRR initiative. Tariff effective 4/1/12. Changes made to sections 3.2, 5, 5.1.1, 5.1.3, 5.1.4, 5.1.5, 7.1, and Appendix Attachment B sections B.2.2, B.2.5, and B.2.7</td>
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<td>PRR 425 for changes to RUC Availability Bids for RA resources. Changes made to sections 3.3 and 7.1</td>
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<td>PRR 427 for changes associated with the Ramping Flexibility Nomogram initiative. Change made to section 12.1.</td>
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<td>PRR 384 for changes to Open/Isolated Intertie Handling. Inserted new section 8.2.2 and renumbered existing sections 8.2.2 and 8.2.3. Appended new fields to tables described in Attachment B sections B.2.2 and B.2.4.</td>
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<td>PRR 412 for changes to Bidding and Mitigation of Commitment Costs. Changes made to sections 4.1, 5.1.1.1.1, 5.1.1.1.2, 8.2.1.3, and attachment D section D.5.4. Appended new fields</td>
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| 13      | 04-07-2011 | PRR285 for changes to Attachment C detailing the use and timing of the Gas Price Index for Default Energy Bids.  
PRR381 for changes to Attachment G related to an update in the gas delivery points. Replaced SoCal Border with City Gate. |
| 12      | 01-28-2011 | PRR 341 for changes associated with the Convergence Bidding Initiative.                                                                      |
| 11      | 01-05-2011 | PRR 357 for changes Attachment G, Section G.2. Updated language associated with the gas transportation rate for SCE and SDG&E.               |
| 10      | 12-06-2010 | PRR 278 for changes associated with the Multi-Stage Generation initiative.  
PRR 309 for changes associated with the Transition Components of the Multi-Stage Generation initiative. Attachment H added to BPM for this functionality.  
Miscellaneous changes as defined in PRR 278 attachments.  
PRR 308 for changes to section 5.1.1.1.4 (formerly, this was section 5.1.1.1.3) |
| 9       | 10-06-2010 | PRR 306 Language/Link changes in Sections 10., 11.4, and 12                                                                                |
| 8       | 09-14-2010 | PRR 282 Clarification Language for Wheeling Through Transactions (Section 3.4.1)                                                             |
| 7       | 08-10-2010 | PRR 161 entries for PDR                                                                                                                   |
| 6       | 07-14-2010 | PRR 217 for Phase 1 Data Release – Transmission Constraints  
Section 12.1 Prices, Section 10.2 added for Transmission Reports in CMRI, Section D1 correction of language for non RMR DEB calculation. |
| 5       | 03-31-2010 | PRR 172 AS HASP Tariff changes, misc. terminology reference clean up.)  
PRR for 169 Emergency change Use of the Gas Price Index in Default Energy Bid/ SIBR generated bid and Start Up/ Minimum Load calculations. |
<p>| 4       | 01-15-2010 | Startup/MinLoad revisions based off new Tariff language. Main body for reference to 30 days vs. 6 month, Att. E, and Att. G.(PRR 133)      |
| 3       | 12-31-2009 | Standard Capacity Product (SCP) and Day-Ahead AS Must Offer Obligation changes, 2 new OASIS reports, some minor edits. (PRR 88)          |</p>
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<td>Master File Update for Appendix B for UI / API interface PRR 38; Replaced MRTU term with California ISO Nodal Market; misc. reference (hyperlink) / Rules cleanup. (PRR 38)</td>
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1. **Introduction**

Welcome to the CAISO *BPM for Market Instruments*. In this Introduction you will find the following information:

The purpose of the CAISO BPMs

What you can expect from this CAISO BPM

Other CAISO BPMs or documents that provide related or additional information

1.1 **Purpose of CAISO Business Practice Manuals**

The Business Practice Manuals (BPMs) developed by CAISO are intended to contain implementation detail, consistent with and supported by the CAISO Tariff, including: instructions, rules, procedures, examples, and guidelines for the administration, operation, planning, and accounting requirements of CAISO and the markets. Exhibit 1-1 lists CAISO BPMs.

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1.2 Purpose of this Business Practice Manual

The CAISO BPM for Market Instruments describes how Scheduling Coordinators (SCs) submit Bids, including Self-Schedules and Inter-SC Trades to CAISO, the process CAISO uses to validate Bids, including Self-Schedules and Inter-SC Trades, and how SCs access data on accepted Bids, Self-Schedules, Inter-SC Trades, and prices.

Although this BPM is primarily concerned with market instruments, there is some overlap with other BPMs. Where appropriate; the reader is directed to the other BPMs for additional information.

The provisions of this BPM are intended to be consistent with the CAISO Tariff. If the provisions of this BPM nevertheless conflict with the CAISO Tariff, the CAISO is bound to operate in accordance with the CAISO Tariff. Any provision of the CAISO Tariff that may have been summarized or repeated in this BPM is only to aid understanding. Even though every effort will be made by CAISO to update the information contained in this BPM and to notify Market Participants of changes, it is the responsibility of each Market Participant to ensure that he or she is using the most recent version of this BPM and to comply with all applicable provisions of the CAISO Tariff.

A reference in this BPM to the CAISO Tariff, a given agreement, any other BPM or instrument, is intended to refer to the CAISO Tariff, that agreement, BPM or instrument as modified, amended, supplemented or restated.

The captions and headings in this BPM are intended solely to facilitate reference and not to have any bearing on the meaning of any of the terms and conditions of this BPM.

1.3 References

Other reference information related to this BPM includes:

- Other CAISO BPMs
- CAISO Tariff
- SIBR Tutorial

Interface Specification for Market Results Services

1.4 Acronyms & Specialized Terms

The definition of acronyms and words beginning with capitalized letters are given in the BPM for Definitions & Acronyms and as stated below.
2. Markets & Market Processes

Welcome to the Markets & Market Processes section of the CAISO BPM for Market Instruments. In this section you will find the following information:

A high level description of the Day-Ahead and Real-Time Markets

A description of the products and services traded through CAISO

Market bidding timelines and primary activities of CAISO

2.1 Day-Ahead Market Processes

The Day-Ahead Market (DAM) for both virtual and physical Bids closes at 1000 hours on the day before the Trading Day and consists of a sequence of processes that determine the hourly locational marginal prices (LMPs) for Energy and AS, as well as the incremental procurement in Residual Unit Commitment (RUC) while also determining Reliability Must Run (RMR) dispatch levels and mitigating Bids that may be in excess of Local Market Power Mitigation limits. These processes are co-optimized to produce a Day-Ahead Schedule at least cost while meeting local reliability needs.

The LMPs resulting from these processes are used for the Day-Ahead Settlement. The following subsections present an overview of these processes for the Trading Day.

2.1.1 Market Power Mitigation Determination

The Market Power Mitigation (MPM) function determines the Bids that are subject to bid mitigation based on specified criteria. If the criteria are met, the MPM mitigates the affected Bids for the relevant Trading Hours of the Trading Day. The MPM function is performed prior to the Integrated Forward Market process.

The details of Market Power Mitigation are provided in CAISO Tariff Section 31.2 and its subsections and are described in more detail in the BPM for Market Operations.

2.1.2 Integrated Forward Market

The Integrated Forward Market (IFM) is a market for trading Energy and Ancillary Services (AS) for each Trading Hour of the Trading Day. The IFM uses Clean Bids for Energy and AS from SIBR, (those Bids that have passed the Bid validation and processing procedures), RMR Proxy Bids, and the mitigated Bids to the extent necessary following the MPM process in order to clear the Supply and Demand Bids and to procure Ancillary Services to meet CAISO’s AS requirements at least Bid Costs over the Trading Day.
2.1.3 Residual Unit Commitment

The Residual Unit Commitment (RUC) process is a reliability function for committing resources and procuring RUC capacity not reflected in the Day-Ahead Schedule following the IFM (as Energy or AS capacity), in order to meet the difference between the CAISO Forecast of CAISO Demand (including locational differences) and the Demand reflected in the Day-Ahead Schedules for each Trading Hour of the Trading Day.

Short, Fast, and Medium Start Units in general do not receive a binding commitment instruction in RUC. Units are notified at the end of the DAM if they are selected for RUC. Such resource commitment decisions are determined in the Real Time Market. Commitment instructions are issued closer to the Real-Time Dispatch, based on the unit’s Start-Up Time. Long Start Units can receive a binding commitment instruction in RUC. Non-binding commitment instructions for Extremely Long-Start Resources are produced through RUC and are reviewed by the CAISO Operator through the Extremely Long-Start Unit Commitment process. The CAISO Operator will manually confirm and communicate any binding commitment instructions.

2.1.4 Extremely Long-Start Unit Commitment

The commitment of resources that require a start up time of greater than 18 hours or notification earlier than the publication of the Day-Ahead Schedule will be considered in the RUC and the Extremely Long-Start Commitment process. This process will be executed after the completion of the DAM. Bids for ELS units are used for both the current Trading Day and Trading Day D+1. Extra Long Start (ELS) units will receive binding commitment instruction in the Extra Long Commitment (ELC) process. The ELC process is detailed in the BPM for Market Operations Section 6.8.1.

It should be noted that current SIBR Rules associated for RA For Long Start Units (that are registered in the Masterfile as Must Offer Obligation) will create bids as necessary for these resources in the DAM.

While the Must-Offer Obligation resource is not obligated to bid, the CAISO inserting bids does not commit or dispatch the long - start resource for RT because as a long start the commitment time would follow outside of the RTM horizon. However, if the resource has self-committed in the Real-Time, then the CAISO believes that having an RA obligation to offer its RA capacity is consistent with RA policy in similar way as how short-start resources are treated because the resource is physically capable of providing its RA capacity.

2.2 Real-Time Processes

The Real-Time Market closes 75 minutes before the beginning of each Trading Hour (which in turn begins at the top of each hour). A sequence of processes determines the LMPs for each
Trading Hour. The LMPs resulting from these processes are used for the Real-Time Market settlement.

The following subsections present an overview of these processes for the Trading Hour.

### 2.2.1 Market Power Mitigation

The MPM function for the RTM is analogous to the same function that is performed for the DAM. For the Real-Time Market the MPM function covers the Trading Hour and the resultant mitigated Bids are then used by the remaining Real-Time Market processes.

Mitigation in the DAM is a separate process from RTM mitigation. A Bid mitigated in the DAM is either cleared in the IFM or not. If the mitigated Bid does not clear the IFM, then the pre-IFM Bid Mitigation is not used for any downstream consideration (including RTM).

If an SC wants to submit Bids for Energy into the RTM the SC must submit new Bids to the RTM. The Real-Time mitigation process applies to these new Bids.

### 2.2.2 Hour-Ahead Scheduling Process

For most resources, the Hour-Ahead Scheduling Process (HASP) produces advisory schedules in the upcoming hour, providing guidance as to the expected resource output. HASP is also a process where resources may receive fixed schedules from Scheduling Points for Energy and Ancillary Services for a hourly block.

HASP is performed after the Real-Time MPM process. HASP produces: (1) HASP Advisory Schedules for Pricing Nodes (PNodes), and (2) HASP Block Intertie Schedules for System Resources which have submitted hourly block Bids. HASP Block Intertie Schedules can include both Energy and AS. These Intertie Schedules and AS Awards are published approximately 45 minutes before the start of each Trading Hour.

The primary goal of the RTM is to identify supplies to meet the system Demand Forecast and export Schedules. HASP determines HASP Block Intertie Schedules for Hourly block bid System Resources for the Trading Hour (i.e., between T and T+60 minutes) on an hourly basis instead of on a 15-minute basis. This is accomplished by enforcing constraints that ensure that the HASP Block Intertie Schedules for the 15-minute intervals are equal. For reliability reasons, the ISO may ultimately change the 15-minute schedules so that they are no longer equal across all four intervals. The LMP used to settle these schedules is the FMM LMP of the applicable 15-minute FMM interval.
2.2.3 Short-Term Unit Commitment

The Short-Term Unit Commitment (STUC) is a reliability function for committing Short and Medium Start Units to meet the CAISO Forecast of CAISO Demand. The STUC function is performed hourly and looks ahead at least three hours beyond the Trading Hour, at 15-minute intervals.

2.2.4 Real-Time Unit Commitment and Fifteen-Minute Market

The Real-Time Unit Commitment (RTUC) is a market process for committing Fast and Short Start Units and awarding additional Ancillary Services at 15-minute intervals. The RTUC function runs every 15 minutes and looks ahead in 15-minute intervals spanning the current Trading Hour and next Trading Hour. The FMM is the second interval of the RTUC and its results produce a binding settlement.

2.2.5 Real-Time Economic Dispatch

The Real-Time Economic Dispatch (RTED) is a process that dispatches Imbalance Energy and dispatches Energy from AS and normally runs automatically every five minutes to produce Dispatch Instructions. The following two alternative modes to RTED are invoked under abnormal conditions:

- Real-Time Contingency Dispatch (RTCD)
- Real-Time Manual Dispatch (RTMD)

2.2.6 Real-Time Contingency Dispatch

The RTCD function executes upon CAISO Operator action, usually following a Generation or transmission system contingency. The RTCD execution is for a single 10-minute interval and includes all Contingency Only Operating Reserves in the optimization process.

2.2.7 Real-Time Manual Dispatch

The RTMD function executes upon CAISO Operator action, usually when RTED and RTCD fail to provide a feasible solution. The RTMD execution has a periodicity of five minutes for a Time Horizon of five minutes.

2.3 Products & Services

This subsection describes the types of products and services that are traded in CAISO Markets.
2.3.1 Energy

Energy can be supplied from the following resources into CAISO Markets:

- Generating Units
- System Units
- Physical Scheduling Plants
- Participating Loads

System Resources
Virtual Supply and Virtual Demand locations

Energy can be purchased through CAISO Markets only by Scheduling Coordinators to serve:

- Demand within CAISO Balancing Authority Area
- Exports from CAISO Balancing Authority Area

2.3.2 Ancillary Services

The following types of Ancillary Services are traded in CAISO Markets:

- Regulation Up, must be synchronized and able to receive AGC signals
- Regulation Down, must be synchronized and able to receive AGC signals
- Spinning Reserve (must be synchronized, be available in 10 minutes, and be maintainable for 30 minutes)\(^1\)
- Non-Spinning Reserve (must be able to deliver the AS Award within 10 minutes and be maintainable for 30 minutes)

2.3.3 Residual Unit Commitment Capacity

Residual Unit Commitment (RUC) Capacity is the positive difference between the RUC Schedule and the greater of the Day-Ahead Schedule and the Minimum Load level of a resource. The price and availability of this type of capacity depends on the RUC Availability Bids and the optimized RUC Awards.

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\(^1\) The 30 minutes requirement is specified in CAISO Tariff Section 8.4.3(a), Ancillary Service Capability Standards.
The RUC Schedule is the total MW per hour amount of capacity committed through the RUC process, including the MW per hour amount committed in the Day-Ahead Schedule.

2.3.4 Congestion Revenue Rights

Congestion Revenue Rights (CRRs) are financial instruments that may be used by their holders to offset the possible Congestion Charges that may arise in the Day-Ahead Markets for Energy. CRRs are obligations, which may also require their holders to pay Congestion Charges. CRRs are settled based on the Marginal Cost of Congestion component of LMPs derived through IFM.

The BPM for Congestion Revenue Rights describes these rights in greater detail.

2.4 Market Interfaces

CAISO’s portal provides a framework in which to deploy the User Interfaces (UIs) of CAISO’s business applications. The portal allows SCs to access multiple CAISO business applications using a single point of entry and a single digital certificate.

The following CAISO business applications are accessible through the portal:

- SIBR
- CMRI
- CRR
- BAPI
- Outage management system

OASIS (Available but does not require a digital certificate, public information)

SCs interact with CAISO Markets through market interfaces. These market interfaces are described in more detail below.

2.4.1 SIBR

The Scheduling Infrastructure and Business Rules (SIBR) system performs the following tasks:

Provides an SC interface to submit Bids and Inter-SC Trades (IST)

Accepts Bids and IST for Energy, Ancillary Services, and other Energy related products and services (e.g., IFM Load Uplift Obligation) from SCs that are certified to interact with CAISO

Applies business rules to validate and process submitted Bids and IST to ensure that those Bids and IST are valid and modifies Bids for correctness where necessary
Applies business rules to generate DAM and RTM Bids for resources under the Resource Adequacy requirements and RTM Bids for resources with Day-Ahead Ancillary Services or RUC Awards, if these resources do not have valid Bids and RTM Bids used in the STUC process in RTM for the extended time horizon. Refer to section 7.7 of the Market Operations BPM.

Provides SCs information about their Bid and IST validation, modification, and Bid generation

Forwards the final Clean Bids and IST to the relevant CAISO Market

Provides short-term data storage and reports

The details of submitting Bids into SIBR are describe in Section 5 (Energy Bids), Section 6 (Ancillary Services Bids), and Section 7 (RUC Availability Bids).

2.4.2 CAISO Market Results Interface

The Customer Market Results Interface (CMRI) is accessible through the CAISO portal and is the screen through which SCs retrieve proprietary market results, such as DAM Energy Schedules, AS Awards, and RUC Awards. The CMRI supports various reporting functions to facilitate this data retrieval. The details of the reports available through the CMRI are described in detail in Section 10 (Reporting Information).

2.4.3 Master File

The Master File (MF) database is used by CAISO to store the necessary business information and operational data of CAISO’s Market Participants.

MF data includes common information necessary to process scheduling and settlement transactions with the Market Participants and is shared among the CAISO’s business systems.

2.4.4 Automated Dispatch System (Not accessed through Portal)

Automated Dispatch System (ADS) communicates Real-Time commitment and Dispatch Instructions, and Real-Time AS Awards to SCs. The details of the reports provided by ADS are described in detail in Section 11 (Dispatch Information).

2.4.5 Scheduling & Logging of Outages

The outage management system application is the primary method of communicating Outage Management related requests, information updates, approvals, rejections, etc. The outage management system application provides an automated mechanism for MPs and CAISO to communicate the information required for all aspects of Outage Management from submittal of
requests under the Long Range Plan process timing, to requesting and receiving an extension to an Approved Maintenance Outage.

Using outage management system, a Participating TO or Participating Generator or others can perform the following functions:

Submit a request for a new Outage

Receive confirmation of receipt of request from CAISO Outage Coordination Office

Obtain status of an Outage request

Enter Outage Cause Codes (NERC GADS, reason for Outage)

Update an Outage

Change PMin and Ramp Rates

Unit Substitution request

Search database of completed, scheduled or active Outages. This function allows the MP to review only their data and not the data of other MPs.

The details of outage management system operation are provided in the CAISO BPM for Outage Management.

2.4.6 Open Access Same Time Information System

The Open Access Same time Information System (OASIS) provides a web interface for Market Participants to retrieve Public Market Information, such as CAISO Forecast of CAISO Demand, AS requirements, aggregate Schedules, transmission Intertie limits and flows, LMPs, ASMPs (by AS Region), etc. The details of OASIS are provided in Section 12 (Public Market Information).

2.4.7 Business Associate Portal Interface

Business Associate Portal Interface (BAPI) allows access to settlement transaction data including statements, invoices, charge type configurations and historical settlement data through this interface. The details of this process are covered in detail in the CAISO BPM for Settlements and Billing.
2.4.8 Congestion Revenue Rights Auction System & Secondary Registration System

The details of the Congestion Revenue Rights Auction system and Secondary Registration System are provided in the CAISO BPM for Congestion Revenue Rights.
3. **Overview of Market Instruments**

Welcome to the *Overview of Market Instruments* section of the CAISO *BPM for Market Instruments*. In this section you will find the following information:

**Definition of market instruments**

A brief overview of the types of market instruments available in CAISO Markets. The details of the market instruments, and how they operate are provided in the following sections.

Market instruments include Bids, Self-Schedules and Inter-SC Trades (ISTs). A Bid is, in essence, an offer to buy or sell Energy (for Virtual Supply and Virtual Demand Bids, Energy is the only product that is applicable), RUC Availability or Ancillary Services, including Self-Schedules, submitted by Scheduling Coordinators. A Bid in CAISO SIBR system contains all Bid products, services, and Bid components being offered to a specified CAISO Market from a resource. An IST is a transaction between two SCs that is facilitated in CAISO settlement process.

Economic Bids specify prices for MWh amounts of Energy offered. Self-Schedules do not have any prices associated with MWh.

Another market instrument available through CAISO Markets is the CRR. Details about the CRR allocation, auction, and settlement provisions are covered in detail in the CAISO *BPM for Congestion Revenue Rights*.

### 3.1 Energy Bids

In order to participate in CAISO Energy Markets, SCs must submit Energy Bids. Energy Bids comprise both Economic Bids and Self-Schedules. These Bids can be either Supply Bids or Demand Bids.

There are two categories of Bid components – daily components that are constant across the Trading Day and hourly components that can vary by Trading Hour. The details of these Bid components are described in Section 4 (Bid Requirements).

SCs may submit Bids to the DAM beginning seven days prior to the Trading Day and up until 1000 hours the day prior to the Trading Day. SCs may submit Real-Time Market Bids beginning when the Day-Ahead Schedules are published at 1300 hours the day prior to the Trading Day and up until 75 minutes prior to the start of the relevant Trading Hour.
Bids submitted to the DAM apply to the 24 hours of the next Trading Day and are used in both the IFM and the RUC process. Bids submitted to the RTM apply to a single Trading Hour. SCs representing System Resources who wish to participate in the HASP as an hourly block bid submit those eligible Bid components as part of their RTM Bids. ²

The bidding rules for both the DAM and the RTM are described in detail in Section 5 (Energy Bids).

3.1.2 Virtual Bids

Virtual Energy Bids are Economic Bids and do not include Self-Schedules. These Bids can be at any Eligible PNode, or Eligible Aggregated PNode location and be a Virtual Supply Bid and/or Virtual Demand Bid at that location.

Virtual Bids exist in the DAM only, SCs may submit Virtual Demand or Virtual Supply Bids to the DAM beginning seven days prior to the Trading Day and up until 1000 hours the day prior to the Trading Day, this is the same process established for the physical Bids.

3.2 Ancillary Services Bids

Four types of Ancillary Services are used by CAISO in its markets – Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve. For Metered Sub-Systems (MSS) Load Following Up/Down is also handled through submission of Bids for Ancillary Service. Participating Generators and Dynamic System Resources are eligible to provide all Ancillary Services for which they are certified. Certified Non-Dynamic System Resources are eligible to provide Operating Reserves (Spinning Reserves and Non-Spinning Reserves) only³.

Registered Proxy Demand Resources and Certified Participating Loads are eligible to provide Spinning and Non-Spinning Reserve. Reliability Demand Response Resources are not eligible to provide Ancillary Services. SCs that wish to provide Ancillary Services to CAISO may either submit Ancillary Services Bids or Self-Provide Ancillary Services. A Bid to supply Ancillary

² CAISO does not accept bids for the next Trading Day between the time of Market Close at 1000 hours and the publication of the DAM results at 1300 hours.

³ Dynamic Resource-Specific System Resources are identified generating resources located outside of the CAISO Balancing Authority Area that can be dynamically controlled to maintain the frequency and net Interchange of the CAISO Balancing Authority Area. These Dynamic Resource Specific System Resources may be certified to supply Regulation Up and Regulation Down to the CAISO. A Non-Dynamic Resource-Specific System Resource is an identified generating resource located outside of the CAISO Balancing Authority Area that cannot be dynamically controlled. Dynamic and Non-Dynamic System Resources are System Resources which are not tied to specific generating resources, and which are subject to dynamic control (Dynamic System Resources) or not subject to dynamic control (Non-Dynamic System Resources).
Services specifies prices for MW amounts (or in the case of Regulation Up and Down, prices for both Capacity and Mileage) of each Ancillary Service to be supplied. However, there is no quantity in a Mileage bid, only price. A Submission to Self-Provide Ancillary Services is not a Bid. CAISO’s acceptance of Self-Provided Ancillary Services occur prior to Ancillary Service Bid evaluation in the relevant market.

SCs submit Bids for AS in both the DAM and the RTM. Bids for AS in the RTM are submitted incrementally from any DAM AS Awards. DAM AS Awards are binding commitments and cannot be reduced in RTM (with the exception of a reduction in available capacity as notified through outage management system).

Any Self-Provided AS are used to reduce the AS Obligation for the SC that Self-Provided those AS. Details of this are provided in the BPM for Settlements and Billing.

Any Self-provided AS in excess of an SC’s Obligation are credited at the user rate for the respective AS. The BPM for Market Operations specifies how the market prices for AS is determined.

The bidding rules for Ancillary Services are described in detail in Section 6 (Ancillary Services Bids).

### 3.3 Residual Unit Commitment Availability Bids

SCs may submit RUC Availability Bids on behalf of eligible capacity that is not subject to a RUC obligation. See section 6.7.2.6 of the BPM for Market Operations. SCs with eligible capacity that is subject to a RUC obligation have no bidding requirement as the RUC obligated capacity will be optimized automatically using a $0/MW per hour RUC Availability Bid.

Upon publication of the DAM results, the CAISO notifies SCs of any RUC Awards (through CMRI). RUC Availability payments are based on RUC selection, irrespective of whether the Generating Unit is required to Start-Up or not. A Generating Unit receives a Start-Up instruction at the appropriate time. If the CAISO instructs a Generating Unit subject to a RUC Award to Start-Up, the unit is eligible for RUC Cost Compensation, which includes Start-Up and Minimum Load Cost compensation, and Bid Cost Recovery, in addition to the RUC Availability payment. For RUC Availability Bids details see Section 7 (Residual Unit Commitment Availability Bids) and attachment A (Bid Validation Rules).

The RUC Award is the portion of the RUC Capacity that is not subject to an RMR Dispatch and is not RA Capacity. RUC Capacity is the portion of the RUC Schedule excluding the minimum load and any DA Energy Schedule. RUC Capacity that is subject to an RMR Dispatch and RA Capacity are not entitled to RUC Availability payments. RUC Award is entitled to RUC
Availability payment regardless of its Start-up time. In other words, RUC Awards from Short Start or Fast Start units are entitled to RUC Availability payment. This is based on CAISO Tariff Section 31.5.6, Eligibility for RUC Compensation.

### 3.4  **Import & Export Bids**

An Import Bid is a Supply Bid at a Scheduling Point. An Export Bid is a Demand Bid at a Scheduling Point. Both Import Bids and Export Bids must be submitted with positive MW values. As in the case of all Bids, Import and Export Bids must include a Resource Location. The resource Location is the resource ID for a Generating Unit, System Unit, Participating Load or System Resource registered in the Master File. The CAISO will assign separate Resource IDs to SCs for submitting Import Bids and Export Bids at specific Scheduling Points. These Import and Export resource IDs will be maintained in the Master File. SCs must request the CAISO to assign unique Resource IDs which will be used to nominate: Scheduling Point, Energy type, and direction of flow (e.g., Import and Export). In addition, if the SC desires separate Settlement treatment for each transaction submitted at the same Scheduling Point, the SC must use a separate resource ID. Accordingly, each SC must request sufficient resource IDs to meet its business needs. Import Bids and Supply Bids are in all other respects subject to the bidding requirements set forth in Sections 4, 5, 6, and 7 of this BPM.

#### 3.4.1  **Wheeling Through Transactions**

A Wheeling Through transaction consists of an Export Bid and an Import Bid submitted as either Self-Schedules or Economic Bids and which utilizes the same Wheeling reference. The Wheeling reference is a unique Wheeling identifier registered in the Master File.

If a Wheeling Through transaction does not have a matching Wheeling reference that links the Import Bid to the Export Bid by the time the DA Market closes, SIBR will remove the Wheeling Bid Component that includes the Wheeling reference and all other hourly Bid Components for that Trading Hour such as any Self Schedule (ETC/TOR/PT/LPT) or Energy. This will make the bid invalid for the DA Market. For RTM Bids the same conditions apply.

SIBR will accept Wheeling Through transactions that do not have a matching MW quantity in the Export Bid and Import Bid. The balancing of Wheeling MW quantities is managed by the IFM or RTM during optimization. Please refer to the Market Operations BPM for information concerning how the IFM and RTM treat unbalanced MW quantities of a Wheeling Through transaction.

Wheeling Through transactions submitted in the DAM result, if accepted, in a Day Ahead Schedule. In order to preserve the wheel, the Wheel Through transaction must be resubmitted in the RTM as a wheel. (Section 6. Day Ahead Market Processes and Section 7. Real-Time Market Processes.)
The CAISO business rule validations that apply to Wheeling Through transactions are summarized in section 8.2.

### 3.4.2 IBAA Imports Marginal Losses Adjustment Eligibility

For import schedules to the CAISO Balancing Authority Area that use the southern terminus of the California-Oregon Transmission Project (COTP) at the Tracy substation and pay the Western Area Power Administration (Western) or Transmission Agency of Northern California (TANC) for line losses, the CAISO will replace the marginal cost of losses of the applicable default LMP that applies to such IBAA transactions. Scheduling Coordinators (SCs) need to establish system resource IDs to submit bids, including self-schedules, to establish schedules that are eligible for this loss adjustment consistent with the CAISO Tariff. Prior to obtaining these system resource IDs, SCs need to certify to use these IDs for bids, including self-schedules, that only originate from transactions that use the COTP and pay Western or TANC for losses. A self-certification form is available on the CAISO website: [http://www.caiso.com/docs/2005/10/05/2005100520241822328.html](http://www.caiso.com/docs/2005/10/05/2005100520241822328.html). By actually using such system resource IDs, the SC represents that covered transactions use the COTP and pay Western or TANC for line losses. Schedules and dispatches settled under such resource IDs shall be subject to a default IBAA LMP for imports that accounts for the marginal cost of losses as if an actual physical generation facility exists at the southern terminus of COTP at the 500 kV Tracy scheduling point rather than the marginal cost of losses specified in CAISO Tariff Section 27.5.3.

### 3.4.3 Circular Scheduling

The CAISO prohibits a Scheduling Coordinator from submitting Bids that result in a Schedule or Schedules being awarded to that single Scheduling Coordinator that has an associated E-Tag reflecting a source and sink in the same Balancing Authority Area. This prohibition is not enforced in market software, but instead via a settlement mechanism that removes the incentive for submitting such prohibited schedules. See the BPM for Market Operations Appendix Attachment H for more information.

Exceptions to this rule are allowed if any of the following conditions exist:

- The Schedule(s) includes a transmission segment on a DC Intertie.
- The Schedule(s) involves a Pseudo-Tie generating unit delivering energy from its Native Balancing Authority Area to an Attaining Balancing Authority Area.
- The Schedule(s) are used either to: (i) serve Load that temporarily has become isolated from the CAISO Balancing Authority Area because of an Outage; or (ii) deliver Power from a Generating Unit that temporarily has become isolated from the CAISO Balancing Authority Area because of an Outage.
The Schedule(s) involve a Wheeling Through transaction that the Scheduling Coordinator can demonstrate was used to serve load located outside the transmission and Distribution System of a Participating TO.

However, if the circumstances leading to one of the above four conditions being met were excluded from consideration and the resulting hypothetical Schedule(s) could still have an associated E-Tag reflecting a source and sink in the same Balancing Authority Area, then the prohibition and associated settlement still applies.

### 3.4.4 Transaction identifiers for Intertie Resources not associated with Physical Resources

The CAISO will assign a transaction identifier (Transaction ID) and apply it to any transaction that is not associated with an Intertie resource registered in the Master File, which is where the CAISO stores all the physical characteristics utilized through the CAISO Market systems. Those include Bids at the Interties for system resources that are not dynamic, Pseudo-Ties, or Resource-Specific System Resources, and Virtual Bids.

Each Transaction ID will not be registered in the CAISO’s Master File but will be generated when Bids are submitted. Such Transaction ID will persist through the CAISO Market systems, from bid validation through Market Clearing and Settlements. The Transaction ID helps the CAISO identify Bids and Schedules, enforce scheduling limits, and facilitate Intertie schedule tagging of physical bids and Intertie referencing for Virtual Bids, without the need to register an unbounded number of resources in the Master File.

This does not affect dynamic resources that undertake dynamic transfers, which are transfers (imports and exports) of Energy or Ancillary Services from such resources interconnected in one Balancing Authority Area into another Balancing Authority Area pursuant to a dynamic signal in the Balancing Authorities’ Energy Management Systems. Dynamic resources may participate in the Day-Ahead Market as well as the Fifteen Minute Market and 5-minute Real-Time Market.

Each dynamic resource is registered with the CAISO and assigned a unique Resource ID registered in the CAISO’s Master File.

Similarly, this does not affect Bids from static (non-dynamic) resources that are certified to provide Ancillary Service imports or exports in the Day-Ahead Market and/or the Fifteen Minute Market, but cannot do so in the 5-minute Real-Time Market.

### 3.5 Inter-SC Trades

CAISO facilitates Inter-SC Trades (ISTs) of Energy, Ancillary Services, and IFM Load Uplift Obligation through the settlement process. ISTs do not have any impact on the scheduling or dispatch of resources. They affect only the financial settlement process. Only trades that SCs
want to settle through CAISO are submitted in the IST process. All other trades are settled bilaterally between individual SCs. There is no limit on the number of ISTs each SC may participate in.

ISTs for the Day-Ahead Market may be submitted beginning seven days prior to the Trading Day up to 11:00 hours (HE 11) the day prior to the Trading Day. ISTs for the Real-Time Market may be submitted beginning at 00:00 hours the day prior to the Trading Hour up to 45 minute prior to the Trading Hour.

Inter-SC Trades in the RTM are submitted incrementally to the DAM Inter-SC Trades.

3.5.1 Inter-SC Trades of Energy

The role of Inter-SC Trades (IST) of Energy is to facilitate contractual deliver and settlement of bilateral power purchase contracts. Inter-SC Trades are a settlement service that the CAISO offers to parties of bilateral contracts as a means to offset CAISO settlements charges against the bilateral contractual payment responsibilities. CAISO facilitates Inter-SC Trades of Energy through the settlement process. An IST of Energy consists of a quantity in MWs traded between two SCs for a specific Trading Hour at a specific location. There are two types of ISTs:

**Physical Trades (PHY)** – where the Inter-SC Trade is backed by a physical resource (applies to Generating Units only). There is no limit on the number of PHY ISTs in which an SC can participate. The SC for the physical resource that supports the PHY can submit a Bid, including a Self-Schedule Bid into the relevant market. In the event that sufficient Generation is not scheduled to meet the quantity of the PHY IST, the difference is converted to a Converted Physical Trade (CPT) and settled at the relevant Trading Hub price.

**ISTs at Aggregated Pricing Nodes that are also defined Trading Hubs or LAPs (APN)** – where the IST is not backed by a physical resource. SC’s may participate in one APN IST per SC counterparty at each APN Location, that is either a defined Trading Hub or LAP, per Trading Hour. For example, there can only be one IST per hour between SC1 and SC 2 at the Existing Generation Zone Trading Hub NP15. The CAISO will facilitate ISTs (APN) only at Existing Zone Generation Trading Hubs and Default LAPs.

3.5.2 Inter-SC Trades of Ancillary Services

CAISO also facilitates ISTs of Ancillary Services obligation, i.e., the obligation to pay AS Charges for the amount of Demand represented by the SC. There are four types of AS that SCs can trade:

- Regulation Up
An IST of AS consists of a quantity in MWs traded between two SCs for a specific Trading Hour and for a specific Ancillary Service type. The IST of AS is a trade of the obligation to pay CAISO charges for Ancillary Services. CAISO settles with the two parties to the trade based on the quantity of the AS Obligation traded times the user rate for the AS Inter-SC Trades for the specific Trading Hour. Once the SC responsible for the Demand has traded its AS obligation, the SC to which the obligation has been traded may meet that obligation with Self-Provided AS or purchasing AS from CAISO.

Since CAISO charges a single user rate for each AS per hour, separate ISTs for AS are not required for both the DAM and the RTM. Hence, SCs may submit ISTs for Ancillary Services only in RTM beginning 0000 hours of the day prior to the Trading Day and up to 45 minutes prior to the Trading Hour. This is based on CAISO Tariff Sections 28.2.3, 28.2.2 and 6.5.4.1.2.

3.5.3 Inter-SC Trades of IFM Load Uplift Obligation

CAISO facilitates ISTs of the IFM Load Uplift Obligation between SCs. Inter-SC Trades of IFM Load Uplift Obligation enable a SC to transfer any amount of the IFM Load Uplift Obligation (MW) to another SC. An IST of IFM Load Uplift Obligation consists of a quantity in MWs traded between two SCs for a specific Trading Hour of the IFM.

Since CAISO charges a single user rate for IFM Load Uplift Obligation per hour, separate ISTs for IFM Load Uplift Obligation are not required for both the DAM and the RTM. Hence, SCs submit ISTs only in the RTM for IFM Load Uplift Obligation beginning 0000 hours of the day prior to the Trading Day, up to 45 minutes prior to the Trading Hour. Trades of IFM Load Uplift Obligation are not location specific, since CAISO calculates a system-wide user rate for this charge. This is based on CAISO Tariff Sections 28.2.3, 28.2.2 and 6.5.4.1.2.

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4 Since CAISO charges a single system-wide tariff for each AS, specification of a location for AS ISTs is not required.
5 IFM Load Uplift Obligation is calculated net of the cost of AS.
4. **Bid Requirements**

Welcome to the *Bid Requirements* section of the CAISO *BPM for Market Instruments*. In this section you will find the following information:

- A list of the Bid components that are constant across a Trading Day
- A list of the Bid components that can change hourly
- A table describing the bidding limitations for Non-Generator Resources (NGRs)

Day-Ahead Bids and Self-Schedules include information on each of the 24 Trading Hours in the Trading Day. Some Bid components are constant for the Trading Day, while other components can vary from hour to hour. Exhibit 4-1 shows which Bid components are constant across the Trading Day – referred to in the exhibit as Daily Requirements – and those that can change hourly – Hourly Requirements.

### 4.1 Daily & Hourly Bid Components

This section is based on CAISO Tariff Section 30.4 Election for Start-Up and Minimum Load Costs and Section 39.6.1.6. (Start-Up and Minimum Load Costs are not applicable to Virtual Bids).

Bid components are divided into two categories:

**Daily Bid components** – These Bid components are constant across all Trading Hours in a Trading Day and do not change for that Trading Day.

**Hourly Bid components** – These Bid components can vary in each Trading Hour of the Trading Day.

With the exception of three Bid components (Start-Up, Minimum Load and Transition Costs), all Bid components can vary each day, and are submitted by SCs as part of their DAM and RTM Bids. For Start-Up and Minimum Load Bid components, the SC selects one of two alternatives: Registered Cost or Proxy Cost. The elections are independent; that is, a Scheduling Coordinator electing either the Proxy Cost option or Registered Cost option for Start-Up Costs may make a different election for Minimum Load Costs. The Start-Up and Minimum Load Bid components are constant for each Trading Day for the period submitted.
If Registered Cost is selected for Start-Up and/ or Minimum Load, the SC submits information for Start-Up and/ or Minimum Load respectively to CAISO for entry into the Master File. Subject to the applicable cap, these values can be updated every 30 days through the Master File Update process that is described in Attachment B. Start-Up and Minimum Load Costs under the Registered Cost Option may not exceed 150 percent of the unit’s Projected Proxy Cost for Start-Up and Minimum Load Costs. If the SC selects the Registered Cost Option, the values will be fixed for 30 days unless the resources costs, as calculated pursuant to the Proxy Cost option, exceed the Registered Cost option, in which case the SC may switch to the Proxy Cost option for the balance of the 30 day period. (see Attachment G for details).

If the Proxy Cost option is selected, the Start-Up and Minimum Load Bid components are calculated daily for each Generating Unit based on the daily gas price and includes, in addition, auxiliary power costs (for Start-Up), O&M costs (Minimum Load adder as listed in Exhibit 4-2, the adder is a value registered in the Master File), greenhouse gas allowance Start-Up and Minimum Load costs if applicable (see Attachment K), the Market Services Charge and System Operations Charge components of the Grid Management Charge (GMC) (for Start-Up), the Market Services Charge and System Operations Charge components of the GMC and the Bid Segment Fee component (for Minimum Load), and a major maintenance cost adder if applicable (see Attachment L), which may be different for Start-Up and Minimum Load. The process that CAISO uses to calculate the daily gas price is shown in Attachment C, and there is an example in section 8.2.1.3 for a Generated Bid. The SC is also allowed to submit a Start-Up and/ or Minimum Load Cost Bid as part of a generator’s Bid in the Day-Ahead Market (DAM) as long as the SC elected the Proxy Cost option for them and the submitted Bid is not negative and is less than or equal to the proxy cost calculated using the daily Gas Price Index.

Transition Cost will be calculated as the product of the Transition Fuel and the Daily Gas Price Index associated with the resource. This will be the same for all Multi-Stage Generating Resources regardless of the resource’s elected Cost option.

The details of the Bid components are described in subsequent sections.

<table>
<thead>
<tr>
<th>Exhibit 4-1: Daily &amp; Hourly Bid Components</th>
</tr>
</thead>
<tbody>
<tr>
<td>Daily Components</td>
</tr>
<tr>
<td>------------------</td>
</tr>
<tr>
<td>Start-Up</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>-------------------</td>
</tr>
<tr>
<td>Minimum Load</td>
</tr>
<tr>
<td>Transition Costs</td>
</tr>
<tr>
<td>Energy Bid Curve</td>
</tr>
<tr>
<td>Self-Schedule</td>
</tr>
<tr>
<td>Ancillary Services</td>
</tr>
<tr>
<td>Regulation Down</td>
</tr>
<tr>
<td>Daily Components</td>
</tr>
<tr>
<td>-----------------------</td>
</tr>
<tr>
<td>Regulation Up</td>
</tr>
<tr>
<td>Spinning Reserve</td>
</tr>
<tr>
<td>Non-Spinning Reserve</td>
</tr>
<tr>
<td>Ramp Rate</td>
</tr>
<tr>
<td>Operational Ramp Rate</td>
</tr>
<tr>
<td>Operating Reserve Ramp Rate</td>
</tr>
<tr>
<td>Regulation Ramp Rate</td>
</tr>
<tr>
<td>Contingency Dispatch Indicator</td>
</tr>
<tr>
<td>Intertie Minimum Hourly Block (DA)</td>
</tr>
</tbody>
</table>
| Dispatch Option       | ✓                 | ✓                      | A Bid option that determines the participation of an Intertie resource in the Real-Time Market:  
  - Hourly: submission of a HASP Block Intertie Schedules  
  - Once: submission of an Economic Hourly Block Bid with Intra-Hour option.  
  - 15min: dispatched |
<table>
<thead>
<tr>
<th>Daily Components</th>
<th>Hourly Components</th>
<th>Submitted through SIBR</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>in each 15 minute Interval of a Trading Hour with a flat Dispatch for all 5 minute Dispatch Intervals of that 15 minute Interval. Dynamic: dispatched in each 5 minute Dispatch Interval of a Trading Hour.</td>
</tr>
<tr>
<td>Pump Shut-Down Cost</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Pumping Cost</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Energy Limit (Maximum and Minimum Daily)</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>RUC</td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Capacity Limit</td>
<td>✓</td>
<td>✓</td>
<td>(Unrelated to Capacity Limit Indicator). Specifies an upward limit on the total Energy and Ancillary Services awards for a given hour. Limit must be set no lower than the maximum of the highest energy bid or the RA obligation amount. Used mainly for partial RA or non-RA resources who want to limit the total award when bidding multiple services.</td>
</tr>
<tr>
<td>Distribution Factors</td>
<td>✓</td>
<td>✓</td>
<td>These apply to Generating Units only. Generation Distribution Factors are provided on a per-unit basis.</td>
</tr>
</tbody>
</table>
VER Forecast

Comment:
SC may submit through SIBR. If none are provided through SIBR, CAISO will use Generation Distribution Factors (GDF) from the GDF Library based on historical generation pattern.

If a Variable Energy Resource (VER) chooses to supply an energy forecast, the forecast shall be submitted through SIBR. Forecast is submitted for a configurable rolling time horizon as often as every 5 minutes.

Exhibit 4-2: Default O&M Cost Adders effective April 1, 2012 ($/MWh)

<table>
<thead>
<tr>
<th>Generation Technology</th>
<th>Recommended VOM Cost Adder ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar</td>
<td>$0.00</td>
</tr>
<tr>
<td>Nuclear</td>
<td>$1.00</td>
</tr>
<tr>
<td>Coal</td>
<td>$2.00</td>
</tr>
<tr>
<td>Wind</td>
<td>$2.00</td>
</tr>
<tr>
<td>Hydro</td>
<td>$2.50</td>
</tr>
<tr>
<td>Combined Cycle and Steam</td>
<td>$2.80</td>
</tr>
<tr>
<td>Geothermal</td>
<td>$3.00</td>
</tr>
<tr>
<td>Landfill Gas</td>
<td>$4.00</td>
</tr>
<tr>
<td>Combustion Turbine &amp; Reciprocating Engine</td>
<td>$4.80</td>
</tr>
<tr>
<td>Biomass</td>
<td>$5.00</td>
</tr>
</tbody>
</table>

Alternatively, a custom O&M adder may be negotiated with the CAISO. Custom O&M adders approved are only applicable to the specific resource or configuration (if the resource is a multi-
stage generator) that is active in the Master File for the associated scheduling coordinator (SC) who applied for the custom O&M adder with the CAISO. The custom O&M adders will be reviewed and potentially renegotiated or terminated under the following circumstances:

1. **Change in scheduling coordinator**
   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**
   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 Pmin/Pmax changes
   d. resource or a configuration within a multi-stage generator retires
   e. resource changes generation technology type in Master File

3. **Change in O&M costs**
   a. conditions underlying resources’ original negotiated O&M are no longer applicable or accurate

4. **Change in any other material item which might affect the approved custom O&M adder.**

It is the responsibility of the scheduling coordinator to ensure that the conditions and data underlying any custom O&M adder for a resource accurately reflect current conditions and to notify the CAISO of any changes that may affect their custom O&M adder. To the extent that any custom O&M adder for the resource or multi-stage generator configurations require modification or reinstatement after termination, the corresponding scheduling coordinator for the resource should negotiate a custom O&M adder with the CAISO to avoid the risk of invalid O&M adder when changes occur either at the resource level or at the scheduling coordinator level. Until a new custom O&M adder has been established, a temporary O&M adder may be negotiated between the scheduling coordinator and the CAISO.

### 4.1.1 Bidding limitations for NGRs

NGRs are resources that operate as either Generation or Load and that can be dispatched to any operating level within their entire capacity range but are also constrained by a MWh limit to
(1) generate Energy, (2) curtail the consumption of Energy in the case of demand response, or (3) consume Energy.

More generally, NGRs are resources that have a continuous operating range from a negative to a positive power injection; i.e., these resources can operate continuously by either consuming energy or providing energy, and can seamlessly switch between generating and consuming electrical energy. An NGR functions like a generation resource and can provide energy and AS services. Because of the continuous operating range, NGRs do not have minimum load operating points, state configurations, forbidden operating regions, or offline status (unless on outage). Therefore, they do not have startup, shutdown, minimum load, or transition costs.

The regulation energy management (REM) option allows non-generator resources that require an offset of energy in the real time market to provide regulation. NGRs that select this option can only participate in the ISO’s regulation markets.

The following table describes the special bidding limitations for NGR’s.

**Exhibit 4-3: Bidding limitations for NGRs**

<table>
<thead>
<tr>
<th>Bid component</th>
<th>Allowed for non REM?</th>
<th>Allowed for REM?</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start-Up</td>
<td>No</td>
<td>No</td>
<td>By nature NGRs do not have startup costs.</td>
</tr>
<tr>
<td>Minimum Load</td>
<td>No</td>
<td>No</td>
<td>By nature NGRs do not have minimum load costs.</td>
</tr>
<tr>
<td>Transition Costs</td>
<td>No</td>
<td>No</td>
<td>By nature NGRs do not have transition costs.</td>
</tr>
<tr>
<td>Energy Bid Curve</td>
<td>Yes</td>
<td>No</td>
<td>NGRs selecting the REM option are not allowed to participate in the energy market.</td>
</tr>
<tr>
<td>Self-Schedule</td>
<td>Yes</td>
<td>No</td>
<td>Because NGRs selecting the REM option are not allowed to participate in the energy market, they cannot self-schedule. Non REM NGRs can self-schedule as price takers only.</td>
</tr>
<tr>
<td>Ancillary Services</td>
<td></td>
<td></td>
<td>NGRs are not allowed to self-provide Ancillary Services</td>
</tr>
<tr>
<td>Regulation Down</td>
<td>Yes</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Regulation Up</td>
<td>Yes</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>Bid component</td>
<td>Allowed for non REM?</td>
<td>Allowed for REM?</td>
<td>Comment</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>----------------------</td>
<td>------------------</td>
<td>-------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Spinning Reserve</td>
<td>Yes</td>
<td>No</td>
<td>NGRs selecting the REM option are only allowed to supply regulation.</td>
</tr>
<tr>
<td>Non-Spinning Reserve</td>
<td>Yes</td>
<td>No</td>
<td>NGRs selecting the REM option are only allowed to supply regulation.</td>
</tr>
<tr>
<td>Operational Ramp Rate</td>
<td>Yes</td>
<td>Yes</td>
<td>NGRs are limited to two segments. One ramp rate for charging and one ramp rate for discharging</td>
</tr>
<tr>
<td>Operating Reserve Ramp Rate</td>
<td>No</td>
<td>No</td>
<td>NGRs are not allowed to submit Operating Reserve Ramp Rates. Operational Ramp rate shall be used for procurement of AS.</td>
</tr>
<tr>
<td>Regulation Ramp Rate</td>
<td>No</td>
<td>No</td>
<td>NGRs are not allowed to submit Regulation Ramp Rates. Operational Ramp rate shall be used for procurement of AS.</td>
</tr>
<tr>
<td>Contingency Dispatch Indicator</td>
<td>Yes</td>
<td>N/A</td>
<td>Does not apply to REM resources because they cannot supply spinning or non-spinning reserve.</td>
</tr>
<tr>
<td>Intertie Minimum Hourly Block</td>
<td>N/A</td>
<td>N/A</td>
<td>Does not apply to NGRs because NGRs must be located within the CAISO balancing authority.</td>
</tr>
<tr>
<td>Dispatch Option</td>
<td>N/A</td>
<td>N/A</td>
<td>Does not apply to NGRs because NGRs must be located within the CAISO balancing authority.</td>
</tr>
<tr>
<td>Pump Shut-Down Cost</td>
<td>No</td>
<td>No</td>
<td>By nature NGRs do not have pump shut-down costs.</td>
</tr>
<tr>
<td>Pumping Cost</td>
<td>No</td>
<td>No</td>
<td>By nature NGRs do not have pumping costs.</td>
</tr>
<tr>
<td>Daily Energy Limit (Maximum and Minimum Daily)</td>
<td>No</td>
<td>No</td>
<td>However NGRs do bid an upper and lower charge limit, which is a similar concept.</td>
</tr>
<tr>
<td>RUC</td>
<td>No</td>
<td>No</td>
<td>NGR Resources do not participate in RUC</td>
</tr>
<tr>
<td>Capacity Limit</td>
<td>Yes</td>
<td>Yes</td>
<td>Assumption is that all underlying resources are operating in the same mode, either all must be in charging mode or all must be in discharging mode.</td>
</tr>
<tr>
<td>Distribution Factors</td>
<td>Yes</td>
<td>Yes</td>
<td>Assumption is that all underlying resources are operating in the same mode, either all must be in charging mode or all must be in discharging mode.</td>
</tr>
<tr>
<td>VER Forecast</td>
<td>N/A</td>
<td>N/A</td>
<td>Does not apply to NGRs because</td>
</tr>
</tbody>
</table>
Bid component | Allowed for non REM? | Allowed for REM? | Comment
--- | --- | --- | ---
NGRs cannot be a VER.  
The following bid components apply to NGRs only

<table>
<thead>
<tr>
<th>Bid component</th>
<th>Allowed for non REM?</th>
<th>Allowed for REM?</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lower Charge Limit</td>
<td>Yes</td>
<td>Yes</td>
<td>Lowest stored energy that should be maintained in the device. Cannot be lower than the minimum stored energy value registered in the Master File.</td>
</tr>
<tr>
<td>Upper Charge Limit</td>
<td>Yes</td>
<td>Yes</td>
<td>Highest stored energy that should be maintained in the device. Cannot be higher than the maximum stored energy value (MSE) registered in the Master File.</td>
</tr>
<tr>
<td>Initial DA State of Charge (SOC)</td>
<td>Yes</td>
<td>No</td>
<td>The initial SOC in MWh for the resource on the first participation interval of the trading day in the Day Ahead Market. If not provided, value is determined based on the ending SOC from previous day if available, or zero (0MWh) if not available from previous day. Note: For the real time market operations, SOC values are submitted and utilized by EMS every 4 seconds via telemetry. EMS provides SOC values to the Real Time Market approximately every 1 minute.</td>
</tr>
</tbody>
</table>
5. **Energy Bids**

Welcome to the Energy Bids section of the CAISO BPM for Market Instruments. In this section you will find the following information:

- A general description of the Energy Bid components
- A description of the Bid requirements for Supply Bids
- A description of the Bid requirements for Demand Bids

For physical Bids SCs submit Energy Bids to participate in CAISO Markets for Energy. Bids are submitted by SCs for each market (DAM and RTM) for the resources associated with each SC. SCs submit Bids for each resource. A single Energy Bid can include both Economic Bid components and Self-Schedule components, as shown in Exhibit 5-1, as well as operational information that applies to the entire range of Economic Bid components and Self-Schedule components. Exhibit 5-1 shows a Bid that contains a Self-Schedule of 20 MW, and an Economic Bid of 80MW.

For Virtual Bids at a location SCs must submit in the DAM with an Energy Bid which will only contain the Economic Bid Components.
Exhibit 5-1: Example of Energy Bid with Self-Schedule & Economic Bid Components

SCs submit Energy Bids for the following types of resources:

**Generating Unit** – Bids for certain types of Generating Units have additional Bid validation requirements. These include: Physical Scheduling Plant, a Pumped-Storage Hydro Unit, a System Unit, a Generating Unit fueled by natural gas a Fast-Start Unit, and Multi-Stage Generating Resources (MSG). In addition there are resources that are modeled like a Generating Unit (i.e. Inter-Tie Generators or Dynamic Resource-Specific Generating Resources and Proxy Demand Resources, and Reliability Demand Response Resources) that are also subject to the bidding rules associated to Generating Units.

**Export Resource** – Demand at a Scheduling Point.

- **System Resource (an Import Resource)** – can be registered as firm, non-firm, wheeling, a Dynamic System Resource, or unit contingent. For Non-Dynamic System Resources registered as an Hourly Pre-dispatch in the Master File, bid options include a flag to require the bid to be considered as an hourly block schedule, and a flag to allow a single curtailment for the remainder of the hour for accepted block schedules. For Non-Dynamic System Resources not registered as an Hourly Pre-dispatch in the Master File, resources may participate as a 15 minute dispatchable resource in addition to the above options.
Participating Load – Load that has executed a Participating Load Agreement, including Pumping Load.

Non-Participating Load – Load that has not executed a Participating Load Agreement, internal to the CAISO Balancing Authority Area and cannot submit Bids for Ancillary Services.

Multi-Stage Generating Resources - Consistent with the rules in the CAISO Tariff, Generating Units and Dynamic Resource-Specific System Resources can be modeled and participate in the CAISO Markets as MSGs.

Virtual Resources—Virtual Supply or Virtual Demand Bids at a given Eligible PNode or Eligible Aggregated PNode.

Non-Generator Resources— NGRs are resources that have a continuous operating range from a negative to a positive power injection. NGRs are generally treated like Generating Units, but some bidding limitations apply due to their unique operating characteristics. See section 4.1.1 for more details.

Eligible Intermittent Resources – (EIR) is a Variable Energy Resource that is registered with the ISO as a Generating Unit or a Dynamic System Resource. A Variable Energy Resource is powered by an energy source that is renewable, and cannot be stored, and has uncontrolled variability. An EIR is treated similar to a Generating Unit or a System Resource by the CAISO systems. However, to be dispatched for energy in the real-time market the EIR must either supply the CAISO with a short term forecast of its output or use the CAISO’s resource specific forecast. Depending on whether the resource self-schedules or bids economically, the CAISO will either use the forecast value as an adjustment to the self-schedule or as an upper economic operating limit. See the BPM for Market Operations for details.

The following sections describe the details associated with different components of the Energy Bids.

5.1 Supply Bids

(The content of this section is based on CAISO Tariff Section 30.5.2, Supply Bids)

Physical Supply Bids can be both Economic Bids for Supply and Self-Schedule Bids for Supply. The same resource can submit both Economic and Self-Schedule Bids for Supply for the same Trading Hour. Virtual Supply Bids will be Economic Bids only. Supply Bids can be submitted in
the IFM based on market timelines and SIBR rules. Scheduling Coordinators submitting these Bid components for a Multi-Stage Generating Resource must do so at the registered MSG Configuration level and not at the Generating Unit or Dynamic Resource-Specific System Resources. Scheduling Coordinators must utilize the MSG Configuration ID for this purpose.

Scheduling Coordinators may register the number of Multi-Stage Generating Resource configurations as are reasonably appropriate for the unit based on the operating characteristics of the unit, which may not, however, exceed a total of ten configurations and cannot be fewer than two configurations.

There may be multiple MSG Configurations in a single bid, but each MSG Configuration must be submitted under the single MSG Configuration ID.

Each Energy Supply Bid is uniquely identified by:

**Scheduling Coordinator ID** – This is the identification of the SC that submits the Bid. (For Virtual Bids the Scheduling Coordinator must be associated to a single Convergence Bidding Entity)

**Market Type** – Either DAM or RTM. (DAM only for Virtual Supply Bids)

**Bid period** – Identifies the specific CAISO Market for which the Bid applies. For a DAM Bid, the Bid period is the specific Trading Day. The Bid in the DAM is considered to be for a 24 hour period but any Bid component that is designated as hourly can differ for each hour. For a RTM Bid, the Bid is for a specific Trading Hour.

**Resource ID** – Identifies the resource. It must be a valid resource associated with the SC specified in the Bid. In order to participate in CAISO Markets, the resource must be certified. This is described in more detail in the *BPM for Scheduling Coordinator Certification and Decertification*.

**Configuration ID (MSG resources only)** - and Multi-Stage Generating Resource configuration ID as applicable.

**Location** - Eligible PNode or Eligible Aggregated PNode for Virtual Supply Bids.

**Transaction ID** - Identification characters generated by the CAISO when Bids are submitted by Scheduling Coordinators at Interties for resources whose characteristics are not registered in the Master File such as Non-Dynamic System Resources. The Transaction IDs remain associated with specific transactions represented in the Bid from Bid validation through
Settlement of the Bid if cleared through the CAISO Markets. Transaction IDs are not assigned to Bids associated with resources whose characteristics are registered in the Master File such as Resource Adequacy Capacity, Transmission Ownership Rights, Existing Transmission Contracts, resources certified for Ancillary Services or other contractual agreements that the CAISO is required to honor.

5.1.1 Day-Ahead Economic Bids for Supply

Day-Ahead Economic Bids for Supply must include two types of information that the SCs submit to CAISO:

- Financial Information (detailed in Section 5.1.1.1 below)
- Operating Information (detailed in Section 5.1.1.2 below)

5.1.1.1 Financial Information

Financial information includes the cost components of Bids, and any associated operating limitations.

5.1.1.1.1 Start-Up Component

This Bid component applies only to Generating Units (and to Dynamic and Non-Dynamic Resource-Specific System Resources, Proxy Demand Resources, and Reliability Demand Response Resources, which are modeled in the same way as Generating Units). Start-Up component contains:

**Start-Up Time** – The Start-Up Time is a staircase curve with up to three segments reflecting the conditions for Start-Up (Warm, Intermediate and Cold). The Start-Up Time (expressed in minutes) is expressed as a function of Cooling Time (expressed in minutes) and can range from zero to infinity. (CAISO inserts registered Master File Data).

**Start-Up Cost** – The Start-Up Cost is a staircase curve with up to three segments reflecting the conditions for Start-Up (Warm, Intermediate and Cold). Start-Up Cost is expressed in $, as a function of Cooling Time (in minutes) and can range from zero to infinity. The value used for Start-Up Cost is determined as follows:

If the SC has elected the Registered Cost option for Start-Up Cost and the SC submits registered value, CAISO overwrites any submitted Bid component with the Start-Up Cost.

---

6If a value is submitted in the Bid for the Start-Up Cost, it will be overwritten by the Master File value. If no value for Start-Up Cost is submitted in the Bid, CAISO will insert the Master File value for the Start-Up Cost into the bid.
data from the Master File. Under this option, the registered value can be changed every 30 days through the Master File change process.

If the SC has elected the Proxy Cost option for the Start-Up Cost, the CAISO calculates this value daily using the daily Gas Price Index. In addition, SCs may include Start-Up Cost Bids into their DAM Bid submissions as long as the Start-Up Cost value is not negative and is less than or equal to the Start-Up Cost value calculated using the daily Gas Price Index. If the SC does not submit a Start-Up Cost Bid or when the submitted Start-Up Cost Bid is greater than the calculated Start-Up Cost, the CAISO uses the Start-Up Cost calculated using the daily Gas Price Index. The process used by CAISO to calculate the daily Gas Price Index is described in Attachment C.

### Example of Start-Up Bid Component

<table>
<thead>
<tr>
<th></th>
<th>Cooling Time (Minutes)</th>
<th>Start-Up Time (Minutes)</th>
<th>Start-Up Cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Warm</td>
<td>0</td>
<td>600</td>
<td>6,500</td>
</tr>
<tr>
<td>Intermediate</td>
<td>240</td>
<td>1390</td>
<td>9,800</td>
</tr>
<tr>
<td>Cold</td>
<td>480</td>
<td>1400</td>
<td>12,000</td>
</tr>
</tbody>
</table>

The Start-Up Cost component is a daily Bid component so a single set of values are used for the entire Trading Day in both the DAM and the RTM.

If the SC has selected Registered Cost option for the Start-Up Cost, this value can be changed every 30 days through the Master File change process. The process used by CAISO to calculate the daily Gas Price Index is described in Attachment C. Whenever the Start-Up Cost submitted by the SC is overwritten, the CAISO notifies the SC that the daily Bid Start-Up Cost has been overwritten by the default values when the Bid confirmation is provided to the SC.

#### 5.1.1.1.2 Minimum Load Cost Component

This Bid cost component applies to Generating Units and Proxy Demand Resources. The Minimum Load Cost component contains:
The hourly cost of operating the Generating Unit at Minimum Load, expressed in $/hr.\(^7\)

The Minimum Load Cost is constant for the entire Trading Day in both the DAM and the RTM.

If the SC has elected the Registered Cost option for Minimum Load Cost, and the SC submits data for this component, CAISO overwrites the Bid component with the data from the Master File. If the SC selected Registered Cost Minimum Load Cost, this value can be changed every 30 days through the Master File.

If the SC has elected the Proxy Cost option for Minimum Load Cost, CAISO calculates this value daily based on the daily Gas Price Index. In addition, SCs may include Minimum Load Cost Bids into their DAM Bid as long as the value is not negative and is less than or equal to the Minimum Load Cost value calculated using the daily Gas Price Index. If the SC does not submit a Minimum Load Cost Bid or when the submitted Minimum Load Cost Bid is greater than the calculated Minimum Load Cost, the CAISO uses the Minimum Load Cost calculated using the daily Gas Price Index. The process used by CAISO to calculate the daily Gas Price Index is described in Attachment C.

The CAISO notifies the SC that the Minimum Load Cost component has been overwritten by the default values when the Bid confirmation is provided to the SC.

**5.1.1.1.3 Transition Component**

This Bid component applies to Multi-Stage Generating Resources only and contains the transition related requirements for an MSG’s movement between MSG Configurations. The transition component contains:

**Transition Time** – The notification time for completing a MSG State Transition between MSG Configurations. (CAISO inserts registered Master File Data if none is entered).

**Transition Cost** – The Transition Cost is the operating cost incurred for a MSG State Transition between Online Generating Resource States and is a biddable parameter. (CAISO calculates the Transition Cost as described in Attachment H.)

**Transition Definition** – The Transition Definition is Transition data composed of Initial and Final Online Generating Resource States (the From Configuration and the To Configuration)

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\(^7\) If a value is submitted in the Bid for the Minimum Load Cost it will be overwritten by the Master File value. If no value for Minimum Load Cost is submitted in the Bid, CAISO will insert the Master File value for the Minimum Load Cost into the bid.
5.1.1.1.4 Energy Bid Curve

Energy Bid Curve is required to be submitted on behalf of a resource providing RA Capacity that has an obligation to offer Energy into the DAM, as described in the BPM for Reliability Requirements, unless a Bid on behalf of the unit is submitted as a Self-Schedule. For all other resources, the Energy Bid Curve component is optional. Specific requirements for submitting Energy Bid Curves are detailed in Attachment F.

The Energy Bid Curve component contains:

An Energy Bid Curve of up to 10 segments (defined by 11 pairs) of Energy offer price ($/MWh) and operating level (MW) for each of the 10 segments. The Energy Bid Curve begins at the Minimum Load level or the sum of its Self-Schedules, whichever is greater, of the Generating Unit.

Resources which have had their market-based rate authority suspended per CAISO Tariff Appendix II and wish to submit an Energy Bid Curve may only submit at a price of $0/MWh, or the Scheduling Coordinator may submit a Self-Schedule.

Example of Energy Bid Curve Component for a Generating Unit with a PMin of 70MW and a PMax of 500 MW

<table>
<thead>
<tr>
<th>Segment</th>
<th>Operating Level (MW)</th>
<th>Energy Price $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>70</td>
<td>25</td>
</tr>
<tr>
<td>2</td>
<td>150</td>
<td>30</td>
</tr>
<tr>
<td>3</td>
<td>200</td>
<td>35</td>
</tr>
<tr>
<td>4</td>
<td>250</td>
<td>40</td>
</tr>
<tr>
<td>5</td>
<td>300</td>
<td>45</td>
</tr>
<tr>
<td>6</td>
<td>340</td>
<td>50</td>
</tr>
<tr>
<td>7</td>
<td>375</td>
<td>55</td>
</tr>
<tr>
<td>8</td>
<td>400</td>
<td>60</td>
</tr>
<tr>
<td>9</td>
<td>450</td>
<td>65</td>
</tr>
<tr>
<td>10</td>
<td>475</td>
<td>75</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>75</td>
</tr>
</tbody>
</table>
Segment 1 is from 70.01 MW to 150.00 MW at an Energy price of $25/MWh; Segment 2 is from 150.01 MW to 200.00 MW, at an Energy price of $30/MWh etc.

The Energy Bid Curve must be monotonically increasing. Separate Energy Bid Curves are submitted for each Trading Hour of the Trading Day.

Reliability Demand Response Resources subject to the Marginal Real-Time Dispatch Option can submit single or multi-segment Energy Bid Curves in the Day-Ahead, similar to generation resources. Reliability Demand Response Resources subject to the Discrete Real-Time Dispatch Option cannot submit any Energy Bid Curves in the Day-Ahead.

5.1.1.2 Operating Information

Energy Supply Bids also contain operating information components that specify constraints on the operation of a Generating Unit or Participating Load.

5.1.1.2.1 Ramp Rate Component

SCs can submit three different types of Ramp Rate information. However, SCs may only submit Operational Ramp Rates for NGRs. In addition to its regular purpose, the Operational Ramp Rate for NGRs will also be used for procurement and dispatch of Ancillary Services.

Operational Ramp Rate (Required if submitting Economic Bid for Supply) – The Operational Ramp Rate of resources limits the Energy schedule changes from one time period to the next in the SCUC. The Operational Ramp Rate is used for scheduling and dispatch when the Generating Unit is not providing Regulation. The Ramp Rate function allows the SCs to declare the Ramp Rate at different operating levels. The Operational Ramp Rate component is a staircase curve of up to four segments (in addition to the Ramp Rate segments needed for modeling Forbidden Operating Regions, which are entered in the Master File8) comprising the Ramp Rate, expressed in MW/minute and associated operating levels, expressed in MW. NGRs are limited to two segments, with one segment defining the charging range (negative side) and the other defining the discharging range (positive side).

If a resource is subject to CAISO Tariff Appendix II, the responsible Scheduling Coordinator must submit an Operational Ramp Rate equal to the maximum Operational Ramp Rate registered in the Master File.

8 Ramp Rates and Forbidden Regions are merged to create a single Clean Bid.
Example of Operational Ramp Rate for a Generating Unit with a PMin of 70 MW and a PMax of 500 MW with no Forbidden Operating Regions

<table>
<thead>
<tr>
<th>MW</th>
<th>MW/Min</th>
</tr>
</thead>
<tbody>
<tr>
<td>70</td>
<td>5</td>
</tr>
<tr>
<td>150</td>
<td>8</td>
</tr>
<tr>
<td>300</td>
<td>7</td>
</tr>
<tr>
<td>400</td>
<td>8</td>
</tr>
<tr>
<td>500</td>
<td>8</td>
</tr>
</tbody>
</table>

Example of Operational Ramp Rate for a Generating Unit with a PMin of 100 MW and a PMax of 600 MW with Forbidden Operating Regions

The resource has four Forbidden Operating Regions stored in the Master File:

- 160 – 200 MW effective Ramp Rate 2 MW/Min
- 280 – 300 MW effective Ramp Rate 3 MW/Min
- 400 – 410 MW effective Ramp Rate 4 MW/Min
- 490 – 500 MW effective Ramp Rate 5 MW/Min

SC submits a four segment Ramp Rate with no Forbidden Operating Regions in its Bid:

<table>
<thead>
<tr>
<th>MW</th>
<th>MW/Min</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>6</td>
</tr>
<tr>
<td>200</td>
<td>7</td>
</tr>
<tr>
<td>300</td>
<td>8</td>
</tr>
<tr>
<td>400</td>
<td>9</td>
</tr>
<tr>
<td>600</td>
<td>9</td>
</tr>
</tbody>
</table>

The final composition of the Ramp Rate after the IFM pulls in the Forbidden Operating Regions from the Master File is:

<table>
<thead>
<tr>
<th>MW</th>
<th>MW/Min</th>
</tr>
</thead>
<tbody>
<tr>
<td>100</td>
<td>6</td>
</tr>
<tr>
<td>160</td>
<td>2</td>
</tr>
<tr>
<td>200</td>
<td>7</td>
</tr>
</tbody>
</table>
Operating Reserve Ramp Rate (Required if submitting Bid for Operating Reserve)  The Operating Reserve Ramp Rate is a single value included in Ancillary Services Bids for Spinning Reserves and Non-Spinning Reserves that represents the Ramp Rate of a resource used in the procurement of Operating Reserve capacity. Further details of this Bid component are described in Section 6 (Ancillary Services Bids).

If a resource is subject to CAISO Tariff Appendix II, the responsible Scheduling Coordinator must submit an Operating Reserve Ramp Rate equal to the maximum Operating Reserve Ramp Rate registered in the Master File.

Regulation Ramp Rate (Required if submitting Bid for Regulation Up or Regulation Down) The Regulation Ramp Rate is a single value included in Ancillary Services Bids for Regulation Up and Regulation Down that represents the Ramp Rate of a resource used in the procurement and dispatch of Regulation Up or Regulation Down capacity. Further details of this Bid component are described in Section 6 (Ancillary Services Bids).

If a resource is subject to CAISO Tariff Appendix II, the responsible scheduling coordinator must submit a Regulation Ramp Rate equal to the maximum Regulation Ramp Rate registered in the Master File.

All three Ramp Rate components are constant across the Trading Day.

5.1.1.2.2  Energy Limit Bid Component

A Scheduling Coordinator is not required to submit this Bid component, for resources that do not have Energy Limits. NGRs are not considered Use-Limited Resources and do not submit this Bid component.

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The Regulation Ramp Rate cannot be greater than any segment of the Operational Ramp Rate that is in the Bid.
Energy Limit constraints apply to a prescribed list of Use-Limited Resources (designated in the Master File) that can generate limited amounts of Energy for a given period of time due to hydro conditions, emission allowances or other regulatory or design considerations. Use-Limited Resources may indicate an Energy Limit in their DAM Bids that applies to their schedule and dispatch throughout the Trading Day. The Energy Limit Bid component contains:

- Maximum Daily Energy Limit (MWh)
- Minimum Daily Energy Limit (MWh). This value must not be greater than zero.

In Generation mode the Minimum value would be 0, in the pumping mode it would be a negative number.

The Energy Limit component is fixed for the entire Trading Day and is submitted only in the DAM.

### 5.1.1.2.3 Distribution Curve Bid Component

The Distribution Curve Bid component contains, for each resource contained in a Physical Scheduling Plant, System Unit, Multi-Stage Generating Resource, or Proxy Demand Resource (excluding Reliability Demand Response Resources), the following information:

- **Distribution Location** – Defined as the Connectivity Node (CNode) associated with the resource
- **Distribution Factor** – Generation Distribution Factor for the resource located at the Distribution Location. Distribution Factors are non-negative numbers that sum to one (1) for the Aggregated Generating Resource or Proxy Demand Resource.

Note: For a Multi-State Generating Resource, each Configuration can specify the Distribution Location and Factor.

### 5.1.1.2.4 Pump Mode of Pumped-Storage Hydro Units & Participating Load

(Required for Pumped-Storage Hydro Units and Pumping Load resources)

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10 See Section 5.2.1.1 for a complete discussion of bidding rules, including for Energy Bids, for Aggregated Participating Load.
Pumped-Storage Hydro Units and Pumping Load can operate in the mode of Generating Unit or Participating Load and can submit Bid components for both modes. Participating Load is treated in the same manner as the pumping component of the Pumped-Storage Hydro Units. In addition to the Start-Up Cost component and the Minimum Load Cost component (associated with operating in generating mode), Pumped-Storage Hydro Units submit the following three Bid components:

**Pump Shut-Down Cost**, expressed in $

**A Pumping Level**, expressed in MW (positive value)

**Pumping Cost** – The hourly cost of pumping, expressed in $/Hr, if the resource is registered as a Pumped-Storage Hydro Unit

### Exhibit 5-2: Pumped-Storage Hydro Unit Bid Component with both Generation and Demand

<table>
<thead>
<tr>
<th>Pumped-Storage Hydro in Pump Mode Bid Components</th>
<th>Compared to</th>
<th>Pumped-Storage Hydro in Generator Mode Bid Components</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shut-Down Cost –</td>
<td>Generator’s Start Up Cost</td>
<td></td>
</tr>
<tr>
<td>Pumping Level</td>
<td>MW Operating Point</td>
<td></td>
</tr>
<tr>
<td>Pumping Cost</td>
<td>Energy Bid component</td>
<td></td>
</tr>
</tbody>
</table>

---

11 While Participating Load is treated as negative generation in the IFM, SCs enter a positive value in the Bid.
Exhibit 5-2 shows a Bid for a Pumped-Storage Hydro Unit that contains both Generation and Demand components for the same Trading Hour. In the above example, the Generation PMin is 70MW and the PMax is 200 MW. The unit submits a pumping bid of 100 MW.

### 5.1.1.3 Multi-Stage Generating Resources

A Scheduling Coordinator cannot submit a Bid to the CAISO Markets for a MSG Configuration into which the Multi-Stage Generating Resource cannot transition due to lack of Bids for the specific Multi-Stage Generating Resource in other MSG Configurations that are required for the requisite MSG Transition.

In order for a Multi-Stage Generating Resource to meet any Resource Adequacy must-offer obligations, the responsible Scheduling Coordinator must submit either an Economic Bid or Self-Schedule for every MSG Configuration in the registered Default Resource Adequacy Path into the Day-Ahead Market, as feasible. If a Multi-Stage Generating Resource holding a Resource Adequacy must-offer obligation fails to meet this requirement, then the ISO will create a Generated Bid or extend an existing bid, as applicable, for every MSG Configuration in the registered Default Resource Adequacy Path.

For the Day-Ahead Market, a Multi-Stage Generating Resource, whether or not holding a Resource Adequacy must-offer obligation, must submit bids from all configurations whose configuration PMax is at a MW output level between the maximum bid-in Energy MW and the higher of the Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin. If a Multi-Stage Generating Resource fails to meet this requirement, then the ISO will create a Generated Bid for every MSG Configuration from which a Bid was required.
5.1.1.4 Non-Generator Resources

Non-Generator Resources (NGRs) may submit a Lower Charge Limit (LCL) for each trading day, which is the lowest stored energy that should be maintained in the resource. This value, in MWh, cannot be lower than the Minimum Stored Energy Limit registered in the Master File. If this component is not provided, the ISO will use the Minimum Continuous Energy Limit value stored in Master File.

In addition, NGRs may submit an Upper Charge Limit (UCL) for each trading day, which is the highest stored energy that should be allowed in the resource. This value, in MWh, cannot be higher than the Maximum Stored Energy limit in the Master File. If this component is not provided, the ISO will use the Maximum Continuous Energy Limit value stored in Master File.

Non-Generator Resources may submit an initial SOC in MWh for the resource to indicate the available energy on the first participation interval of the trading day in the Day Ahead Market. If not provided, the value is determined based on the ending SOC from the previous day if available, or zero (0 MWh) if not available from previous day.

5.1.2 Day-Ahead Economic Virtual Bids for Supply

Day-Ahead Economic Virtual Bids for Supply are limited to the Energy Curve defined in the Bid. For Virtual Bids this is required and the Resource Type selected must be Virtual Supply. Virtual Supply Bids must start at zero (0) MW. The construction of the Energy Bid Curve can be seen in the example below.

Example of Energy Bid Curve Component for a Virtual Supply Bid

<table>
<thead>
<tr>
<th>Segment</th>
<th>Operating Level (MW)</th>
<th>Energy Price $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0</td>
<td>25</td>
</tr>
<tr>
<td>2</td>
<td>150</td>
<td>30</td>
</tr>
<tr>
<td>3</td>
<td>200</td>
<td>35</td>
</tr>
<tr>
<td>4</td>
<td>250</td>
<td>40</td>
</tr>
<tr>
<td>5</td>
<td>300</td>
<td>45</td>
</tr>
<tr>
<td>6</td>
<td>340</td>
<td>50</td>
</tr>
<tr>
<td>7</td>
<td>375</td>
<td>55</td>
</tr>
<tr>
<td>8</td>
<td>400</td>
<td>60</td>
</tr>
<tr>
<td>9</td>
<td>450</td>
<td>65</td>
</tr>
</tbody>
</table>
The Energy Bid Curve must be monotonically increasing.

### 5.1.3 Day-Ahead Self-Schedule Bids for Supply

This section is based on the CAISO Tariff Section 31.4, Uneconomic Adjustments in the IFM

Generating Units may submit a Self-Schedule Bid for Supply for each Trading Hour of the Trading Day. Proxy Demand Resources are limited to Self-schedule only up to the Minimum Load for the resource. Reliability Demand Response Resources (RDRR) can participate in the Day-Ahead Market using Bids similar to Bids used by Proxy Demand Resources in the Day-Ahead Market. RDRR are not allowed to submit Self-Schedule Bids. Any Day-Ahead Schedule for the resource will automatically become a Self-Schedule for the applicable Real-Time hour. The Day-Ahead Schedule is a binding Real-Time Market award even though the RDRR will not receive a real-time dispatch. If the triggering event for utilizing real-time bids on behalf of RDRRs does not occur based on the procedure set forth in Section 7.1 of the BPM for Market Operations, the RDRRs will not receive any Real-Time Dispatch Instruction.

A Self-Schedule Bid component indicates self-commitment by the Generating Unit – i.e., the IFM does not economically commit or de-commit a resource in a Self-Scheduled resource. SCs can submit different types of Self-Schedule Bids that receive different scheduling priorities in the IFM, consistent with registration in the Master File. The list in decreasing order of priority is:

- Reliability Must-Run (RMR) Unit (manually dispatched prior to the DAM or committed through the MPM process)
- Transmission Ownership Right (TOR)
- Existing Transmission Contract (ETC) *Note: Converted Rights (CVR) will be submitted into SIBR using the “Self Schedule ETC” Product Type (DAM only) and have the same priority as ETC.
- Regulatory Must-Run and Regulatory Must-Take (RMT) Generation
- Price Taker (PT)
5.1.3.1 Utilizing Self-Schedule Priorities

The following sections describe the types of Self-Schedule components an SC can submit, in decreasing order of priority. NGRs can only submit Price Taker Self-Schedules.

It is important to note that a TOR, ETC or Wheel that is submitted in the DAM result, if awarded translates into a RT Self-Schedule if no bid or schedule is submitted. In order to preserve the priority of an ETC, TOR, or Wheel the ETC, TOR, or Wheel must be resubmitted in the RTM.

Converted Right (CVR) contracts do not have priority in the RTM.

5.1.3.1.1 Transmission Ownership Right Self-Schedule Bid Component

(Required for TORs)

This is based on CAISO Tariff Section 17, Transmission Ownership Rights (“TOR”).

A TOR Self-Schedule Bid component contains:

- TOR Self-Schedule Identifier – TOR
- TOR Contract Reference Number (CRN)
- TOR Self-Schedule capacity, expressed in MW

TOR Self-Schedules must be submitted balanced between source and sink, and must be within the ownership rights for that TOR, as specified in the Transmission Rights and Curtailment Instructions (TRTC) provided in advance to the CAISO. Sources and sinks must use the same TOR Contract Reference Number. The Contract Reference Number must be registered in the Master File prior to the TOR Self-Schedule taking place. (CAISO Tariff Section 17.3.1, Validation of TOR Self-Schedules).

5.1.3.1.2 Existing Transmission Contract Self-Schedule Bid Component

(Required for ETCs and CVRs)

An ETC Self-Schedule Bid component contains:

- ETC Self-Schedule Identifier – ETC
- ETC/CVR Contract Reference Number (CRN) *Note: CVRs are also defined by the CRN.
- ETC/CVR Self-Schedule capacity, expressed in MW
ETC/CVR Self-Schedules must be submitted balanced between source and sink, and must not exceed the MW amount for the ETC referenced in the Bid, as specified in the TRTC provided in advance to the CAISO. Sources and sinks must use the same ETC/CVR Contract Reference Number. The Contract Reference Number must be registered in the Master File prior to the ETC/CVR Self-Schedule taking place. (See CAISO Tariff Section 16.6.1, Validation of ETC/CVR Self-Schedules).

5.1.3.1.3 Regulatory Must-Run/-Take Self-Schedule Bid Component

(Required for RMTs)

A RMT Self-Schedule Bid component contains:

- Self-Schedule Identifier – RMT
- RMT Reference
  Self-Schedule capacity, expressed in MW

Note, Combined Heat and Power (CHP) resources eligible for RMT are only allowed to submit a RMT self-schedule up to the RMTMax values in the Master File, which may identify a single value or both on and off-peak values. See CAISO Tariff definition for resources eligible for Regulatory Must-Run and Regulatory-Must Take scheduling.

5.1.3.1.4 Price Taker Self-Schedule Bid Component

(Optional for all SCs)

The PT Self-Schedule Bid component contains:

- Self-Schedule capacity, expressed in MW
  Self-Schedule Identifier – PT

  Supporting Resource (Exports only)

5.1.3.1.5 Lower Price Taker Self-Schedule Bid Component

(Optional for all SCs, used for Exports Only)

The LPT Self-Schedule Bid component contains:

- Self-Schedule capacity, expressed in MW
  Self-Schedule Identifier – L PT
5.1.4 Real-Time Economic Bids for Supply

Real-Time Economic Bids for Supply are similar to Day-Ahead Economic Bids for Supply with the major difference that Real-Time Bids are for one Trading Hour, while Day-Ahead Bids are for each Trading Hour in the Trading Day. As with Day-Ahead Economic Bids for Supply, Real-Time Economic Bids for Supply consist of daily and hourly components. If the SC submits daily components for a resource in the Day-Ahead Bid, it is not necessary to submit the components again in the RTM.

5.1.4.1 Financial Information

The following sections define the financial information that SCs submit for the RTM Economic Bids for Supply.

5.1.4.1.1 Start-Up Component

This Bid component applies only to Generating Units, and Proxy Demand Resources. The Start-Up component contains:

Start-Up Time – The Start-Up Time is a staircase curve with up to three segments reflecting the conditions for Start-Up (Warm, Intermediate and Cold). The Start-Up Time (expressed in minutes) is expressed as a function of Cooling Time (expressed in minutes) and can range from zero to infinity. (CAISO inserts registered Master File Data).

Start-Up Cost – The Start-Up Cost component is a staircase curve with up to three segments reflecting the conditions for Start-Up (Warm, Intermediate and Cold). Start-Up Cost is expressed in $, as a function of Cooling Time (in minutes) and can range from zero to infinity. The actual value used for each Generating Unit is limited by values submitted to the Master File, or calculated using daily gas prices.¹² (Not entered by SC through SIBR).

Example of Start-up Bid Component

<table>
<thead>
<tr>
<th></th>
<th>Cooling Time (Minutes)</th>
<th>Start-Up Time (Minutes)</th>
<th>Start-Up Cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Warm</td>
<td>0</td>
<td>600</td>
<td>6,500</td>
</tr>
<tr>
<td>Intermediate</td>
<td>240</td>
<td>1390</td>
<td>9,800</td>
</tr>
</tbody>
</table>

¹² If a value is submitted in the Bid for the Start-Up Cost it will be overwritten by the Master File value. If no value for Start-Up Cost is submitted in the Bid, CAISO will insert the Master File value for the Start-Up Cost into the bid.
SCs are not required to enter Start-Up Cost into their RTM Bid. If the SC does submit data for this component, CAISO overwrites the Bid component with the data from the Master File (except for the Start-Up Time, as described above). If the SC has selected Registered Cost for the Start-Up Cost, this value can be changed every 30 days through the Master File. If the SC has selected Proxy Cost for the Start-Up Cost, CAISO calculates this value daily based on the daily gas price. The process used by CAISO to calculate the daily gas price is described in Attachment C, and there is an example in section 8.2.1.2.

The Start-Up Cost is constant for the entire Trading Day. If a Start-Up Bid component is used in the DAM, the same value is used in the RTM. CAISO notifies the SC that the Start-Up cost has been overwritten by the default values when the Bid confirmation is provided to the SC.

5.1.4.1.2 Minimum Load Cost Component

This Bid component applies only to Generating Units and Proxy Demand Resources. The Minimum Load Cost component contains:

The hourly cost of operating the Generating Unit at Minimum Load, expressed in $/hr\textsuperscript{13} (Not entered by SC).

SCs are not required to enter Minimum Load Cost into their RTM Bid. If the SC does submit data for this component, CAISO overwrites the Bid component with the data from the Master File. If the SC has selected Registered Cost for the Minimum Load Cost, this value can be changed every 30 days through the Master File. If the SC has selected Proxy Cost for the Minimum Load Cost, CAISO calculates this value daily based on the daily gas price. The process used by CAISO to calculate the daily gas price is described in Attachment C.

The Minimum Load Cost is constant for the entire Trading Day. If the SC submits a Minimum Load Cost component in the DAM, it is not necessary to re-submit a value for the RTM. CAISO notifies the SC that the Minimum Load Cost is overwritten by the default values when the Bid confirmation is provided to the SC.

\textsuperscript{13} If a value is submitted in the Bid for the Minimum Load Cost it will be overwritten by the Master File value. If no value for Minimum Load Cost is submitted in the Bid, CAISO will insert the Master File value for the Minimum Load Cost into the bid.
5.1.4.1.3 Transition Component

This Bid component applies only to Multi-Stage Generating Units. The transition process of a MSG resource between Generating Resource States. Transition component contains:

Transition Time – The Transition Time The notification time for completing a MSG State Transition between Online Generating Resource States. (CAISO inserts registered Master File Data if none is entered).

Transition Cost – The Transition Cost is the operating cost incurred for a MSG State Transition between Online Generating Resource States and is a biddable parameter. (CAISO calculates the Transition Cost as described in Attachment H.)

Transition Definition – The Transition Definition is Transition data composed of Initial and Final Online Generating Resource States (the From Configuration and the To Configuration)

5.1.4.1.4 Energy Curve Bid Component

Energy Bid Curve is required to be submitted on behalf of a Generating Unit or Dynamic System Resource providing RA Capacity that has an obligation to offer Energy into the RTM, as described in the BPM for Reliability Requirements unless a Bid on behalf of the unit is submitted as a Self-Schedule. For all other Generating Units, the Energy Bid Curve component is optional. Specific requirements for submitting Energy Bid Curves are referenced in Attachment A of this BPM.

The Energy Curve Bid component contains:

An Energy Bid Curve of up to 10 segments (defined by 11 pairs) of Energy price ($/MWh) and operating level (MW) for each of the 10 segments. The Energy Bid Curve begins at the Generating Unit’s Minimum Load level or the Self-Schedule.

For resources subject to CAISO Tariff Appendix II, the responsible Scheduling Coordinator may only submit an Energy Bid Curve that contains a price of $0/MWh, or the Scheduling Coordinator may submit a Self-Schedule.
Example of Energy Bid Component for a Generating Unit with a PMin of 70 MW and a PMax of 500 MW

<table>
<thead>
<tr>
<th>Segment</th>
<th>Operating Level (MW)</th>
<th>Energy Price $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>70</td>
<td>25</td>
</tr>
<tr>
<td>2</td>
<td>150</td>
<td>30</td>
</tr>
<tr>
<td>3</td>
<td>200</td>
<td>35</td>
</tr>
<tr>
<td>4</td>
<td>250</td>
<td>40</td>
</tr>
<tr>
<td>5</td>
<td>300</td>
<td>45</td>
</tr>
<tr>
<td>6</td>
<td>340</td>
<td>50</td>
</tr>
<tr>
<td>7</td>
<td>375</td>
<td>55</td>
</tr>
<tr>
<td>8</td>
<td>400</td>
<td>60</td>
</tr>
<tr>
<td>9</td>
<td>450</td>
<td>65</td>
</tr>
<tr>
<td>10</td>
<td>475</td>
<td>75</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>75</td>
</tr>
</tbody>
</table>

The Energy Bid Curve must be monotonically increasing.

When submitting Energy Bids in the Real-Time, Reliability Demand Response Resources must select Energy offer prices that are 95-100% of the maximum Energy Bid price stated in the CAISO Tariff.

Reliability Demand Response Resources that have selected the Marginal Real-Time Dispatch Option may submit an Energy Bid Curve consisting of either a single segment or multiple segments in the Real-Time. Reliability Demand Response Resources that have selected the Discrete Real-Time Dispatch Option may only submit an Energy Bid Curve consisting of a single segment in the Real-Time.

5.1.4.1.5 Pumped-Storage Hydro Units

(Required for Pumped-Storage Hydro Units)

In addition to the Start-Up Cost component and the Minimum Load Cost component, Pump-Storage Hydro Units submit the following three Bid components:

**Pump Shut-Down Cost** – If the resource is registered as a Pumped-Storage Hydro Unit. The Pump Shut-Down Cost is expressed in $/hr
A Pumping Level (expressed in MW) – If the resource is registered as a Pumped-Storage Hydro Unit.

Pumping Cost – The hourly cost of pumping, expressed in $/hr, if the Generating Unit is registered as a Pumped-Storage Hydro Unit.

5.1.4.2 Operating Information

Supply Bids on behalf of Generating Units also contain operating information components that specify constraints on the operation of a Generating Unit.

5.1.4.2.1 Ramp Rate Component

The Operational Ramp Rate of resources reflects the limitations of the resources’ abilities to alter output from one time period to the next and is honored in the SCUC. The Operational Ramp Rate constraints are determined by the Operational Ramp Rate function, or the Regulation Ramp Rate (if the Generating Unit provides Regulation) multiplied by a time interval, (e.g., 60 minutes). The Operational Ramp Rate is used for scheduling and dispatch when the Generating Unit is not providing Regulation. For NGRs, however, the Operational Ramp Rate will also be used for procurement and dispatch of Ancillary Services in addition to its regular purpose. SCs may only submit Operational Ramp Rates for NGRs. The Ramp Rate function allows the SCs to declare the Ramp Rate at different operating levels. This Bid component contains:

Operational Ramp Rate (Required) – The Operational Ramp Rate component is a staircase curve of up to four segments comprising the Ramp Rate, expressed in MW/minute and associated operating levels, expressed in MW. NGRs are limited to two segments, with one segment defining the charging range (negative side) and the other defining the discharging range (positive side).

If a resource is subject to CAISO Tariff Appendix II, the responsible Scheduling Coordinator must submit an Operational Ramp Rate equal to the maximum Operational Ramp Rate registered in the Master File.

<table>
<thead>
<tr>
<th>MW</th>
<th>MW/Min</th>
</tr>
</thead>
<tbody>
<tr>
<td>70</td>
<td>5</td>
</tr>
<tr>
<td>150</td>
<td>8</td>
</tr>
<tr>
<td>300</td>
<td>7</td>
</tr>
<tr>
<td>400</td>
<td>8</td>
</tr>
<tr>
<td>500</td>
<td>8</td>
</tr>
</tbody>
</table>
**Operating Reserve Ramp Rate (Required if SC is submitting Bid for Operating Reserve)** –
The Operating Reserve Ramp Rate is a single number included in Ancillary Services Bids for Spinning Reserves and Non-Spinning Reserves that represents the Ramp Rate of a resource used in the procurement of Operating Reserve capacity. Further details of this Bid component are described in Section 6 (Ancillary Services Bids).

If a resource is subject to CAISO Tariff Appendix II, the responsible Scheduling Coordinator must submit an Operating Reserve Ramp Rate equal to the maximum Operating Reserve Ramp Rate registered in the Master File.

**Regulation Ramp Rate (Required if SC is submitting Bid for Regulation Up or Down)** –
The Regulation Ramp Rate is a single number included in Ancillary Services Bids for Regulation Up and Regulation Down that represents the Ramp Rate of a resource used in the procurement and dispatch of Regulation Up or Regulation Down capacity. Further details of this Bid component are described in Section 6 (Ancillary Services Bids).

If a resource is subject to CAISO Tariff Appendix II, the responsible Scheduling Coordinator must submit a Regulation Ramp Rate equal to the maximum Regulation Ramp Rate registered in the Master File.

All three Ramp Rate components are constant across the Trading Day. If the SC has submitted an Operational Ramp Rate for a previous Trading Hour, it is not necessary to resubmit the information for the current Trading Hour.

**5.1.4.2.2 Distribution Bid Component**

The Distribution Curve component contains, for each Physical Scheduling Plant, System Unit or Proxy Demand Resource (excluding Reliability Demand Response Resources), the following information:

**Distribution Location** – Defined as the Connectivity Node (CNode) associated with the Generating Unit.

**Distribution Factor** – Generation Distribution Factor for the Generating Unit located at the Distribution Location. Distribution Factors are non-negative numbers that sum to one (1) for the Aggregated Generating Resource or Proxy Demand Resource.

**5.1.4.3 Multi-Stage Generating Resources**

For Multi-Stage Generating Resources that receive a Day-Ahead Schedule, are awarded a RUC Schedule, or receive an Ancillary Services Award the Scheduling Coordinator must submit an
Energy Bid, which may consist of a Self-Schedule, in the Real-Time Market for the same Trading Hour(s) for either the same MSG Configuration scheduled or awarded in the Integrated Forward Market or committed in RUC. In addition, the Scheduling Coordinator for such Multi-Stage Generating Resources may also submit Bids into the Real-Time Market for up to six other MSG Configurations provided that the MSG Transitions between the MSG Configurations bid into the Real-Time Market are feasible and the transition from the previous Trading Hour are also feasible. For the Trading Hours that Multi-Stage Generating Resources do not have a CAISO Schedule or award from a prior CAISO Market run, the Scheduling Coordinator can submit up to six MSG Configurations into the RTM.

A Scheduling Coordinator cannot submit a Bid to the CAISO Markets for a MSG Configuration into which the Multi-Stage Generating Resource cannot transition due to lack of Bids for the specific Multi-Stage Generating Resource in other MSG Configurations that are required for the requisite MSG Transition.

In order for Multi-Stage Generating Resource to meet any Resource Adequacy must-offer obligations, the responsible Scheduling Coordinator must submit either an Economic Bid or Self-Schedule for every MSG Configuration in the registered Default Resource Adequacy Path into the Real-Time Market, as feasible. If a Multi-Stage Generating Resource holding a Resource Adequacy must-offer obligation fails to meet this requirement, then the ISO will create a Generated Bid or extend an existing bid, as applicable, for every MSG Configuration in the registered Default Resource Adequacy Path.

For the Real-Time Market, a Multi-Stage Generating Resource, whether or not holding a Resource Adequacy must-offer obligation, must submit bids from all configurations whose configuration PMax is at a MW output level between the maximum bid-in Energy MW and the higher of the Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin. If a Multi-Stage Generating Resource fails to meet this requirement, then the ISO will create a Generated Bid for every MSG Configuration from which a Bid was required.

If in any given Trading Hour the Multi-Stage Generating Resource was awarded Regulation or Operating Reserves in the IFM, any Self-Schedules the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be either for the same MSG Configuration for which Regulation or Operating Reserve is Awarded in IFM for that Multi-Stage Generating Resource in that given Trading Hour, or a MSG Configuration which is capable of delivering the entire amount Regulation or Operating Reserve awarded in the IFM. In addition to that, any Submissions to Self-Provide Ancillary Services the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be for the same MSG Configuration for which Regulation or Operating Reserve is Awarded in IFM for that Multi-Stage Generating Resource in that given Trading Hour.
5.1.4.4 Non-Generator Resources

Non-Generator Resources (NGRs) may submit a Lower Charge Limit (LCL) for each trading day, which is the lowest stored energy that should be maintained in the resource. This value, in MWh, cannot be lower than Minimum Stored Energy Limit registered in the Master File. If this component is not provided, the ISO will use the Minimum Continuous Energy Limit value stored in Master File.

In addition, NGRs may submit an Upper Charge Limit (UCL) for each trading day, which is the highest stored energy that should be allowed in the resource. This value, in MWh, cannot be higher than the Maximum Stored Energy limit in the Master File. If this component is not provided, the ISO will use the Maximum Continuous Energy Limit value stored in Master File.

Note: These two limits have to be bid the same as in the Day-Ahead Market.

5.1.5 Real-Time Self-Schedule Bids for Supply

Real-Time Self-Schedule Bids for Supply contain information on nominated Self-Schedule quantities, and operational information. The operational information to be included with a Real-Time Self-Schedule is the same as that which is submitted with an Economic Bid for Supply.

5.1.5.1 Self-Schedule Quantities

A Real-Time Energy Bid can contain Self-Schedule quantities. Self-Schedule quantities contain the capacity the SC wants to include in the Self-Schedule Bid and the type of Self-Schedule. Real-Time Market Self-Schedule quantities are for a single Trading Hour. The following sections describe the types of Self-Schedule components an SC can submit, in decreasing order of priority. NGRs can only submit Price Taker Self-Schedules.

A Reliability Demand Response Resource is not allowed to submit a Self-Schedule Bid in Real-Time. Any Day-Ahead awards for the resource will automatically become a Self-Schedule for the applicable Real-Time hour. The Day-Ahead Schedule is a binding Real-Time Market award even though the RDRR will not receive a real-time dispatch. If the triggering event for utilizing real-time bids on behalf of RDRRs does not occur the RDRRs will not receive any Real-Time Dispatch Instructions.

It is important to note that a TOR/ETC/Wheel that is submitted in the DAM result, if accepted, in a Day Ahead Schedule. In order to preserve an ETC/TOR/Wheel the ETC/TOR/Wheel must be resubmitted in the RTM.
5.1.5.1.1 Transmission Ownership Right Self-Schedule Bid Component
(Required for TORs)

A Transmission Ownership Right (TOR) Self-Schedule Bid component contains:

- TOR Self-Schedule Identifier – TOR
- TOR Contract Reference Number (CRN)

TOR Self-Schedule capacity, expressed in MW

TOR Self-Schedules must be submitted balanced between source and sink, and must be within the allotted ownership rights for that TOR, as specified in the TRTC provided in advance to the CAISO. Sources and sinks must use the same TOR Contract Reference Number. The Contract Reference Number must be registered in the Master File prior to the TOR Self-Schedule taking place. (CAISO Tariff Section 17.3.1, Validation of TOR Self-Schedules).

5.1.5.1.2 Existing Transmission Contract Self-Schedule Bid Component
(Required for ETCs)

An Existing Transmission Contract (ETC) Self-Schedule Bid component contains:

- ETC Self-Schedule Identifier – ETC
- ETC Contract Reference Number (CRN)

ETC Self-Schedule capacity, expressed in MW

ETC Self-Schedules must be submitted balanced between source and sink, and must not exceed the MW amount for the ETC referenced in the Bid, as specified in the TRTC provided in advance to the CAISO. Sources and sinks must use the same ETC Contract Reference Number. The Contract Reference Number must be registered in the Master File prior to the ETC Self-Schedule taking place. (See CAISO Tariff Section 16.6.1, Validation of ETC Self-Schedules).

5.1.5.1.3 Regulatory Must-Run/-Take Generation Self-Schedule Bid Component
(Required for RMTs)

A Regulatory Must-Take/Regulatory Must-Run (RMT) Generation Bid component contains:

- Self-Schedule Identifier – RMT
- RMT Generation Reference – These are registered in the Master File
- Self-Schedule capacity, expressed in MW
Note, Combined Heat and Power (CHP) resources eligible for RMT are only allowed to submit a RMT self-schedule up to the RMTMax values in the Master File, which may identify a single value or both on and off-peak values. See CAISO Tariff definition for resources eligible for Regulatory Must-Run and Regulatory-Must Take scheduling.

5.1.5.1.4 Price Taker Self-Schedule Bid Component

The PT Self-Schedule Bid component contains:

- Self-Schedule capacity, expressed in MW
- Self-Schedule Identifier – PT

5.1.5.1.5 Multi-Stage Generating Resources

For any given Trading Hour, a Scheduling Coordinator may submit Self-Schedules and/or Submissions to Self-Provide Ancillary Services in only one MSG Configuration for each Generating Unit or Dynamic Resource-Specific System Resource.

For Multi-Stage Generating resources, any Self-Schedules the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be either for the same configuration for which Regulation or Operating Reserve is awarded in IFM for that Multi-Stage Generating Resource in that given Trading Hour, or a MSG Configuration which is capable of delivering the entire amount Regulation or Operating Reserve awarded in the IFM. In addition to that, any Submissions to Self-Provide Ancillary Services the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be for the same MSG Configuration for which Regulation or Operating Reserve is Awarded in IFM for that Multi-Stage Generating Resource in that given Trading Hour.

In any given Trading Hour in which a Scheduling Coordinator has submitted a Self-Schedule for a Multi-Stage Generating Resource, the Scheduling Coordinator may also submit Bids for other MSG Configurations provided that they concurrently submit Bids that enable the applicable CAISO Market to transition the Multi-Stage Generating Resource to other MSG Configurations.

5.1.5.2 Operating Information

The operating information submitted with a RTM Self-Schedule Bid component is the same as that required for a Real-Time Economic Bid.
5.2 CAISO Demand Bids

SCs representing Loads (including exports) submit Demand Bids indicating the hourly quantity of Energy in MWh that it intends to purchase in the IFM for each Trading Hour of the Trading Day. Convergence Bidding Entities that are registered must have at least one Scheduling Coordinator ID that is authorized to submit Virtual Demand Bids. Scheduling Coordinators submitting Demand Bid components submit both common information and information that is specific to the type of Demand Bid. The common information included in the Demand Bids is as follows:

- Scheduling Coordinator ID Code
- Location Code for the LAP, PNode or APNode, as applicable (also for Virtual Bids)

For Virtual Bids at a location the Resource Type must be “Virtual Demand”

The specific information associated with different types of Demand Bids is described in the following sections.

5.2.1 Day-Ahead Economic Bids for Demand

SCs may submit Day-Ahead Economic Bids for Demand of the following types:

- Participating Load Bids
- Non-Participating Load Bids

5.2.1.1 Participating Load Demand Bids

Participating Load Bids can be submitted only for those resources that are registered as Pumped-Storage Hydro Units or Pumping Load resources. In addition to the common information contained in all Bids, Participating Load Demand Bids contain the following information:

- Pumping Level, expressed in MWh
- Pumping Cost, expressed in $/Hr
- Ramp Rate, expressed in MW/min, for Pumped-Storage Hydro Units
- Shut-Down Cost, expressed in $

The Pumping Load (individual or aggregated) will be registered in the Master File as a Participating Load.
5.2.1.1 Aggregated Participating Load

An Aggregated Participating Load will be modeled and will participate in the CAISO’s markets as both a Non-Participating Load (NPL) and a Generator. The Aggregated Participating Load will not be able to participate in the CAISO’s markets directly as a Participating Load in Release 1.

The Scheduling Coordinator on behalf of the Aggregated Pumping Load may submit two Bids for the same Trading Day: (1) as a Non-Participating Load, a Day-Ahead Self-Schedule with an Energy Bid Curve with a maximum 10 segments; and (2) as a Generator representing the demand reduction capacity of the Aggregated Participating Load, a submission to Self-Provide Non-Spinning Reserve or a Bid to provide Non-Spinning Reserve. The CAISO will assign two Resource IDs: one for Non-Participating Load Bids and one for Generator Bids (either a Resource ID for a Generating Unit or a Physical Scheduling Plant). Both Resource IDs will be in the Master File on behalf of the Aggregated Participating Load. The Aggregated Participating Load will be treated as a Participating Load for settlement and compliance purposes except that Aggregated Participating Load will be scheduled and settled at Custom LAP rather than an individual PNode. Future software releases will allow Aggregated Participating Load resources to participate directly as Participating Load.

In the DAM when the SC submits the Non-Spinning Reserve Self-Provision or the Non-Spinning Reserve Bid, the SC must ensure that the total Non-Spinning Reserve (including Self-Provided or any Ancillary Services Awards in the market) is available in Real-Time for dispatch. For the Aggregated Participating Load, this means the Demand must be there in real-time for reduction. For example, if the associated Non-Participating Load does not clear the DAM at a load level that is greater than the total Non-Spinning Awards, the market participant must ensure the pumps will be pumping in Real-Time in order to provide the Non-Spinning Reserve; otherwise the payment for Non-Spinning Reserve will be rescinded by No-Pay.

In the DAM when the SC submits the Non-Spinning Reserve Self-Provision and the Non-Spinning Reserve Bid, the SC must indicate that the Non-Spinning Reserve Self-Provision and Non-Spinning Reserve Bid are contingent; the SC must not submit an Energy Bid curve on behalf of the Aggregated Pumping Load as a Generator or the resource may be dispatched for Energy.

The following table provides guidance to Scheduling Coordinators submitting Bids on behalf of Aggregated Participating Load.
5.2.1.2 Non-Participating Load Demand Bids

Non-Participating Load Demand Bids contains the following:

Demand Bid Curve – A staircase curve with up to ten segments, monotonically decreasing, defined by 11 pairs of a MW quantity and price, expressed in $/MWh.

Example of Demand Bid Curve Component for Non-Participating Load

<table>
<thead>
<tr>
<th>Segment</th>
<th>Operating Level (MW)</th>
<th>Energy Price $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>70</td>
<td>75</td>
</tr>
</tbody>
</table>
Demand up to the MW defined by the first segment (i.e., the starting point of the Demand Bid Curve) is treated as a Self-Schedule.

Separate Demand Bid curves can be submitted for each Trading Hour of the Trading Day.

5.2.2 Day-Ahead Economic Virtual Bids for Demand

Day-Ahead Economic Virtual Bids for Demand are limited to the Energy Curve defined in the bid. For Virtual Demand Bids this is required and the Resource Type selected must be “Virtual Demand”. The construction of the Energy Bid Curve can be seen in the example below. Virtual Bids must start at 0 MW.

Example of Virtual Demand Bid Curve Component

<table>
<thead>
<tr>
<th>Segment</th>
<th>Operating Level (MW)</th>
<th>Energy Price $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0</td>
<td>75</td>
</tr>
<tr>
<td>2</td>
<td>150</td>
<td>65</td>
</tr>
<tr>
<td>3</td>
<td>200</td>
<td>60</td>
</tr>
<tr>
<td>4</td>
<td>250</td>
<td>55</td>
</tr>
<tr>
<td>5</td>
<td>300</td>
<td>50</td>
</tr>
<tr>
<td>6</td>
<td>340</td>
<td>45</td>
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<td>8</td>
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<tr>
<td>9</td>
<td>450</td>
<td>30</td>
</tr>
<tr>
<td>10</td>
<td>475</td>
<td>25</td>
</tr>
<tr>
<td>11</td>
<td>500</td>
<td>25</td>
</tr>
</tbody>
</table>
### 5.2.3 Day-Ahead Self-Schedule Bids for Demand

In addition to Economic Bids for Demand, SCs submit Self-Schedule Bids for Demand. With the exception of ETCs and TORs, SCs may only submit Self-Schedules for Demand in the DAM.

SCs can submit Export Self-Schedules in the RTM. (see section 5.2.4)

#### 5.2.3.1 Transmission Ownership Right Self-Schedule Bid Component

In addition to the common Demand Bid information listed in Section 5.2, a Day-Ahead TOR Self-Schedule Demand Bid contains the following:

- TOR Contract Reference Number
- TOR Self-Schedule Demand quantity – expressed in MW

TOR Self-Schedules must be submitted balanced between source and sink, and must be within the allotted ownership rights for that TOR, as specified in the TRTC provided in advance to the CAISO. Sources and sinks must use the same TOR Contract Reference Number. The Contract Reference Number must be registered in the Master File prior to the TOR Self-Schedule taking place. (CAISO Tariff Section 17.3.1, Validation of TOR Self-Schedules).

#### 5.2.3.2 Existing Transmission Contract Self-Schedule Bid Component (also applies to CVRs)

In addition to the common Demand Bid information listed in Section 5.2, a Day-Ahead ETC Self-Schedule Demand Bid contains the following: *Note: Converted Rights (CVR) will be submitted into SIBR using the “Self Schedule ETC” Product Type (DAM only).

- ETC/CVR Contract Reference Number *Note: CVRs are also defined by the CRN.
- ETC Self-Schedule Demand quantity – expressed in MW

ETC/CVR Self-Schedules must be submitted balanced between source and sink, and must not exceed the MW amount for the ETC/CVR referenced in the Bid, as specified in the TRTC provided in advance to the CAISO. Sources and sinks must use the same ETC/CVR Contract Reference Number.

### Table: Segment Characteristics

<table>
<thead>
<tr>
<th>Segment</th>
<th>Operating Level (MW)</th>
<th>Energy Price $/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>7</td>
<td>375</td>
<td>40</td>
</tr>
<tr>
<td>8</td>
<td>400</td>
<td>35</td>
</tr>
<tr>
<td>9</td>
<td>450</td>
<td>30</td>
</tr>
<tr>
<td>10</td>
<td>475</td>
<td>25</td>
</tr>
<tr>
<td></td>
<td>500</td>
<td>25</td>
</tr>
</tbody>
</table>
Reference Number. The Contract Reference Number must be registered in the Master File prior to the ETC Self-Schedule taking place. (CAISO Tariff Section 16.6.1, Validation of ETC Self-Schedules)

5.2.3.3 Price Taker Self-Schedule Bid Component

In addition to the common Demand Bid information listed in Section 5.2, a Day-Ahead PT Self-Schedule Demand Bid contains the following:

PT Self-Schedule Demand Quantity – expressed in MW

The Demand Bid component of a Price Taker Self-Schedule does not have to be balanced with a Supply Bid component.

For PT Self-Schedules from Export Resources in addition to the above information the PT Self-Schedule must also contain:

- Supporting Resource that will be a Generating Unit.

5.2.3.4 Process for Exports to obtain PT Status

For Export Resources that are not RA Resources to be treated as a PT, the SC must designate a Generating Unit that is non-RA/non-RUC as the supporting resource for the PT Self-Schedule for the Trading Hour. The identified Generating Unit may or may not be in the same SC’s portfolio of the Export Resource. Different Generating Units may support the PT Self-Schedules of an Export Resource in different Trading Hours and the same Generating Unit may be identified by several Export Resources to support their PT Self-Schedules in a Trading Hour.

The CAISO will validate according to the SIBR rules that the designated supporting resource for the PT Self-Schedule has available capacity that is greater than or equal to the sum of the relevant PT Export Self-Schedules that claim that same resource multiplied by a configurable Export Capacity factor (such as 100%). If the available capacity is less than the calculated value, SIBR shall convert the PT Export Self-Schedules to LPT Export Self-Schedules in their entirety according to the SIBR Business Rules.

Export Resources that are identified as RA Resources in DAM and RTM may submit PT Self-Schedules up to the registered “RA Capacity” without designating a supporting resource.

SCs may submit Lower Price Taker (LPT) Self-Schedules for Export Resources that are not explicitly supported by a non-RA/non-RUC Generating Unit.
5.2.3.5 Lower Price Taker Self-Schedule Bid Component

In addition to the common Demand Bid information listed in Section 5.2, a Day-Ahead LPT Self-Schedule Demand Bid contains the following:

LPT Self-Schedule Demand Quantity – expressed in MW

The Demand Bid component of a Lower Price Taker Self-Schedule does not have to be balanced with a Supply Bid component.

5.2.3.6 Aggregate Resource Load Bids

Load Distribution Factors (LDFs) for allowed customized aggregation come from the LDF library maintained by CAISO. The LDF Library contains the following:

Distribution Location – the Connectivity Node (CNode) associated with the Custom Load Aggregation Resource

Distribution Factor – Load Distribution Factor for the Custom Load Aggregation Resource located at the Distribution Location

5.2.4 Real-time Economic Bids for Demand

The following resources may submit Demand Bids in the RTM:

Participating Loads

Exports may submit Bid or Self-Schedules in the RTM. However, to the extent an Export is Self-Scheduled and seeks to have the same priority as CAISO Forecast of CAISO Demand, the Export must be supported by non-RA or non-RUC capacity.

The process for both will be submitted using the process described in section 5.2.1.1 and 5.2.2.4.

5.2.5 Real-Time Self-Schedule Demand Bids

SCs can submit Export Self-Schedules in the RTM.
In DAM, an Export Self-Schedule explicitly and adequately supported by the non-RA capacity in the Energy Bid of a Generator or Import resource, that is also not associated with Self-Provided upward A/S capacity, has the same Self-Schedule priority as CAISO Demand. Otherwise, an Export Self-Schedule has a lower Self-Schedule priority than CAISO Demand.

In RTM, Export Self-Schedule already cleared in the IFM or explicitly and adequately supported by the energy bid capacity that is in excess of the RUC Schedule and not occupied by DA upward AS awards and RT upward AS self-provisions of a generator or import resource has the same Self-Schedule priority as CAISO demand forecast. Otherwise, Export Self-Schedule has lower Self-Schedule priority than CAISO demand.

The process for Export Resources to obtain PT status is explained in section 5.2.2.4.

It is important to note that a TOR/ETC/Wheel that is submitted in the DAM result, if accepted, in a Day Ahead Schedule. In order to preserve an ETC/TOR/Wheel the ETC/TOR/Wheel must be resubmitted in the RTM.

### 5.2.5.1 Existing Transmission Contract Self-Schedule Bid Component

In addition to the common Demand Bid information listed in Section 5.2, an ETC Self-Schedule Demand Bid contains the following:

- ETC Contract Reference Number
- ETC Self-Schedule Demand quantity, expressed in MW

ETC Self-Schedules must be submitted balanced between source and sink, and must not exceed the MW amount for the ETC referenced in the Bid, as specified in the TRTC provided in advance to the CAISO. Sources and sinks must use the same ETC Contract Reference Number. The Contract Reference Number must be registered in the Master File prior to the ETC Self-Schedule taking place. (CAISO Tariff Section 16.6.1, Validation of ETC Self-Schedules)

### 5.2.5.2 Transmission Ownership Right Self-Schedule Bid Component

In addition to the common Demand Bid information listed in Section 5.2, a TOR Self-Schedule Demand Bid contains the following:

- TOR Contract Reference Number
- TOR Self-Schedule Demand quantity, expressed in MW.
TOR Self-Schedules must be submitted balanced between source and sink, and must be within the allotted ownership rights for that TOR as specified in the TRTC provided in advance to the CAISO. Sources and sinks must use the same TOR Contract Reference Number. The Contract Reference Number must be registered in the Master File prior to the TOR Self-Schedule taking place. (CAISO Tariff Section 17.3.1, Validation of TOR Self-Schedules)

5.2.5.3 Price Taker Self-Schedule Bid Component

In addition to the common Demand Bid information listed in Section 5.2, a Real-Time PT Self-Schedule Demand Bid contains the following:

PT Self-Schedule Demand Quantity – expressed in MW

The Demand Bid component of a Price Taker Self-Schedule does not have to be balanced with a Supply Bid component.

5.2.5.4 Lower Price Taker Self-Schedule Bid Component

In reference to the Export Priority for lower self schedule in Section 5.2, a Real-Time LPT Self-Schedule Demand Bid contains the following:

LPT Self-Schedule Demand Quantity – expressed in MW

The Demand Bid component of a Lower Price Taker Self-Schedule does not have to be balanced with a Supply Bid component.

The same process for Export Priority applies in Real-Time as in the Day-Ahead. (see Section 5.2.2.4)
6. Ancillary Services Bids

Welcome to the Ancillary Services Bids section of the CAISO BPM for Market Instruments. In this section you will find the following information:

How CAISO procures Ancillary Services

How SCs can self-provide Ancillary Services

A description of the Ancillary Services Bid components

6.1 Procurement of Ancillary Services

This section is based on CAISO Tariff Sections 8.4.7.2, Bidding and Self-Provision of Ancillary Services and CAISO Tariff Section 30.5.2.6, Ancillary Services Bids (Not applicable for Virtual Bids).

SCs may submit an Economic Bid or a Bid for Self-Provided Ancillary Services (AS) from resources located within the CAISO Balancing Authority Area, submit Bids for AS from resources located outside CAISO Balancing Authority Area, or specify Inter-SC Trades of AS (covered in more detail in Section 9.2). Ancillary Services in the DAM and the RTM are comprised of the following:

Regulation Up, which must be synchronized and able to receive AGC signals

Regulation Down, which must be synchronized and able to receive AGC signals

Spinning Reserve (which must be synchronized, be available in 10 minutes, and be maintainable for 30 minutes)

Non-Spinning Reserve (which must be supplied within 10 minutes and be maintainable for 30 minutes)

In HASP, only Operating Reserves (Spinning and Non-Spinning Reserves) are available. HASP only procures Operating Reserves from Non-Dynamic System Resources bidding with the following options: Self-Schedule Hourly Block, Economic Hourly Block, and Economic Hourly Block Bid with Intra-Hour Option.

Certified Participating Generators and Dynamic System Resources are eligible to provide all AS. Certified Non-Dynamic System Resources are eligible to provide Operating Reserves only.
Certified Participating Loads and Proxy Demand Resources are eligible to provide Non-Spinning Reserve only.

The same resource capacity may be offered for more than one Ancillary Services into the same CAISO Market at the same time. SCs may submit Bids to provide Spinning Reserve or Non-Spinning Reserve from certified System Resources, including Dynamic System Resources. In the event that an AS Bid is invalid, the SC receives prompt notification of that invalidity.

For resources that are subject to CAISO Tariff Appendix II, the responsible Scheduling Coordinator may only submit an Ancillary Service Bid that has a price of $0/MWh, or it can also submit a Submission for Self-Provision.

CAISO operates a competitive DAM, the HASP, and RTM to procure AS. Bids for Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve in the DAM must be received no sooner than seven days prior to the Trading Day up to Market Close of the DAM (1000 hours on the day prior to the Trading Day). The Bids contain information for each of the 24 hour Trading Hours of the Trading Day.

Bids for DAM AS in support of Ancillary Services (AS) with Must Offer Obligation (MOO) will be enforced by the SIBR Rules in the DAM. The CAISO will utilize the certified AS capability of those RA Resources that are subject to AS MOO. Use Limited Resources such as hydro generating units and participating load resources will not be subject to AS MOO. The AS MOO is not dependent on whether the RA Capacity is subject to the Standard Capacity Product availability provisions.

In SIBR, if there is no AS Component in a Generating Resource Bid and the Generating Resource or a resource modeled as a Generating Resource specified in that Bid is registered as an RA Resource subject to the AS MOO for the Trading Day, (if the resource is a Multi-Stage Generating Resource the AS capacity is at the MSG Configuration that is bid in and each MSG Configuration has a specific AS Capacity certified to provide AS), an AS Bid Component must be generated with a Capacity equal to the highest available capacity not to exceed the registered Capacity, for that Resource and Trading Day, and with a Price equal to the Default Ancillary Service Bid Price. The Contingency Dispatch Indicator in that Bid will be set to “Yes”. It is possible that if an AS component does exist, it may be extended if needed to meet the requirements. (Tariff Sections 40.6.1, 40.46.4, 40.6.4.3.2, 40.6.8)

Bids for AS in the RTM are submitted incrementally from any DAM AS Awards. DAM AS Awards are binding commitments and cannot be reduced in RTM. CAISO requires SCs to honor their DA AS Awards when submitting AS Bids in the RTM.
Bids for all four AS in the RTM processes must be received at least 75 minutes prior to the commencement of the Trading Hour. The Bids include information for only the relevant Trading Hour. Failure to provide information within the stated timeframes results in the Bids being declared invalid by CAISO.

Scheduling Coordinators submitting Ancillary Services Bids for System Resources to be used in the Real-Time Market must also submit an Energy Bid for the associated Ancillary Services Bid under the same Resource ID in the Real-Time Market, otherwise the bid validation rules in Section 30.7.6.1 of the CAISO Tariff will apply to cover any portion of the Ancillary Services Bid not accompanied by an Energy Bid. As described in Section 34.2.3 of the CAISO Tariff, if the resource is a Non-Dynamic Hourly block bid System Resource, the CAISO will only use the Ancillary Services Bid in the HASP optimization and will not use the associated Energy Bid for the same Resource ID to schedule Energy from the Non-Dynamic Hourly block bid System Resource in the HASP.

Scheduling Coordinators must also comply with the bidding rules associated with the must offer requirements for Ancillary Services specified in Section 40.6 of the CAISO Tariff. For Multi-Stage Generating Resources the AS Bids shall be submitted at the MSG Configuration level.

6.2 Self Provided Ancillary Services

This section is based on CAISO Tariff Section 8.6, Obligations for and Self-Provision of Ancillary Services, and CAISO Tariff Section 30.5.2.6, Ancillary Services Bids.

SCs with submissions to self-provide an Ancillary Service supply all the same information as an AS Economic Bid, excluding the capacity price information for each AS offered by the SC.

Resources that self-provide Regulation Up and Regulation Down do not explicitly self-provide Mileage. Instead, the system will insert a $0 Mileage bid covering the minimum Mileage associated with the self-provided Regulation Up or Down capacity (i.e. resource-specific minimum Mileage multiplier x Regulation capacity).

Scheduling Coordinator must submit an Energy Bid that covers the self-provided capacity prior to the close of the Real-Time Market for the day immediately following the Day-Ahead Market in which the Ancillary Service Bid was submitted.

In addition, resources that have registered with a Metered Subsystem (MSS) that has elected the Load Following option may submit Self-Provision Bids for Load Following Up and Load Following Down.
NGRs may not self-provide Ancillary Services.

6.2.1 Load Following Up

The specific Load Following Up Bid components are the following:

Load Following Up capacity, expressed in MW.

6.2.2 Load Following Down

The specific Load Following Down Bid components are the following:

Load Following Down capacity, expressed in MW.

6.3 Ancillary Service Bid Components

This section is based on CAISO Tariff Section 30.5.2.6, Ancillary Services Bids.

The Bids for Ancillary Services contain both common components and components that are specific to each service. The same Bid components are included for both DAM and RTM Bids for AS, where the DAM includes information for each Trading Hour of the Trading Day and the RTM includes information for just the relevant Trading Hour.

The common components to the AS Bids are described in the Energy Bid component above in Section 5 (Energy Bids).

The following sections describe the specific Bid components for each type of AS.

6.3.1 Regulation Up

The specific Regulation Up Bid components are the following:

- Regulation Up capacity, expressed in MW
- Regulation Up capacity price, expressed as $/MW
- Regulation Up opportunity cost price, expressed in $/MW (optional, CAISO assumes zero if not submitted).
- Regulation Ramp Rate, expressed in MW/Min
- Regulation Up Mileage price, expressed in $/MW (CAISO will insert zero if not submitted).

Note, the resource does not bid in a specific Mileage quantity. The potential Mileage award is constrained by the product of the resource-specific minimum/maximum Mileage multiplier and
the corresponding regulation capacity award. Refer to the *BPM for Market Operations* for more information.

6.3.2 Regulation Down

The specific Regulation Down Bid components are the following:

- Regulation Down capacity, expressed in MW
- Regulation Down capacity price, expressed as $/MW
- Regulation Up opportunity cost price, expressed in $/MW (optional, CAISO assumes zero if not submitted).
- Regulation Ramp Rate, expressed in MW/Min
- Regulation Down Mileage price, expressed in $/MW (CAISO will insert zero if not submitted).

6.3.3 Spinning Reserve Capacity

The specific Spinning Reserve Bid components are the following:

- Spinning Reserve capacity, expressed in MW
- Spinning Reserve price, expressed as $/MW
- Operating Reserve Ramp Rate, expressed in MW/Min

Contingency Dispatch Indicator

6.3.4 Non-Spinning Reserve Capacity

The specific Non-Spinning Reserve Bid components are the following:

- For Generating Units: (also Proxy Demand Resources)
  - Non-Spinning Reserve capacity, expressed in MW
  - Non-Spinning Reserve price, expressed as $/MW
  - Operating Reserve Ramp Rate, expressed in MW/Min
  - Contingency Dispatch Indicator

- For Participating Loads:
  - Non-Spinning Reserve capacity, expressed in MW
  - Non-Spinning Reserve price, expressed as $/MW
  - Operating Reserve Ramp Rate, expressed in MW/Min
  - Contingency Dispatch Indicator
7. Residual Unit Commitment Availability Bids

Welcome to the Residual Unit Commitment Availability Bids section of the CAISO BPM for Market Instruments. In this section you will find the following information:

The information required to submit a RUC Availability Bid

How CAISO validates the RUC Availability Bids

The Residual Unit Commitment (RUC) process occurs after the DA IFM is completed. RUC is a reliability function for committing resources and procuring RUC capacity included in the Day Ahead Schedule resulting from the IFM (as Energy or AS capacity), in order to meet the difference between the CAISO Forecast of CAISO Demand (including locational differences) and the Demand scheduled in the Day Ahead Schedule resulting from the IFM, for each Trading Hour of the Trading Day. The RUC is the process designed to ensure that sufficient on-line resources are available to meet Real-Time Demand. SCs can submit Bids to provide RUC Availability capacity. These Bids are submitted into the DAM process only. For Multi-Stage Generating Resources the RUC Availability Bids shall be submitted at the MSG Configuration level.

This section is based on CAISO Tariff Sections 30.5.2.7, 31.5 and 40.5.2

7.1 RUC Availability Bid

This section is based on CAISO Tariff Section 31.5, Residual Unit Commitment. Virtual Bids and NGRs, and Reliability Demand Response Resources are not eligible to participate in RUC.

The RUC Availability Bid component differs depending on whether the Generating Unit submitting the Bid is under a Resource Adequacy (RA) obligation or not. If a resource is not under a RA obligation, the RUC Availability Bid that the resource submits is interpreted as an incremental amount of capacity that the resource is willing to provide in the Day-Ahead Market for RUC in addition to its Day-Ahead Market Bids and Self-Schedules. In this case the resource would submit a RUC Availability Bid that includes:

- RUC Availability Bid quantity, expressed in MW
- RUC Availability Bid price, expressed in $/MW

These two components must exist together for a valid RUC Availability Bid.

The RUC Availability Cost component can vary hourly throughout the Trading Day.

If a resource is under RA obligation, a certain amount of capacity of this resource is registered with CAISO as RA Capacity. Resources providing RA Capacity must participate in the RUC
process consistent with RA requirements as described in the BPM for Reliability Requirements, by submitting an Energy bid (could be Self-Schedule) up to the registered RA Capacity.

The SC may submit a non-zero RUC Availability Bid only for that portion of its capacity that is not RA Capacity, assuming the capacity is eligible to participate in RUC unless the resource is subject to CAISO Tariff Appendix II, in which case the RUC Availability Bids must be $0/MWh for any capacity bid in. See section 6.7.2.6 of the BPM for Market Operations.

If a resource has a RA obligation, the amount of RA Capacity is registered with CAISO as RA Capacity. RA Capacity that is not a hydroelectric Generating Unit, Pumping Load or exempt Non-Dispatchable Use-Limited Resource pursuant to CAISO Tariff section 40.6.4.3.2, must participate in RUC. The CAISO will automatically optimize all RUC obligated capacity from Generating Units, Imports or System Resources at $0/MW per hour for the full amount of RA Capacity for a given resource.

For Resources that are registered as an RA Resource and are also registered as a Must Offer Obligation (MOO) unit in DAM, SIBR will allow Market Participants to specify a Capacity Limit Indicator to specify whether they want IFM to limit the total capacities committed in IFM to the RA capacity.

If there is no Capacity Limit Indicator specified in a RUC Bid Component for a Trading Hour in a Generating Resource Bid, SIBR will check to see if the RA Flag for the Generating Resource specified in that Bid and for that Trading Hour is “Yes”, if there is then a Capacity Limit Indicator will be generated by SIBR in that RUC Bid Component with a value of “No”.

If there is a Capacity Limit Indicator of “Yes” specified in a RUC Bid Component for a Trading Hour in a Generating Resource Bid, a Capacity Limit must be generated in that RUC Bid Component equal to the RA Capacity.

Real Time bids can be affected by RUC if there is a RUC Award; in the event that there is a RUC Award but no RT bid then an Energy Bid will be created by SIBR. Participants observing RUC Awards that are equal to Pmin should submit an energy bid from Pmin to Pmin+.01 if the RUC capacity is equal to Pmin for the resource.

7.2 RUC Availability Bid Component Validation

The RUC Bid validation follows the Bid validation process described in Section 8 (Bid Submission and Validation). The Bid validation rules related specifically to the RUC Bid components are referenced in Appendix A.
8. Bid Submission & Validation

Welcome to the Bid Submission & Validation section of the CAISO BPM for Market Instruments. In this section you will find the following information:

How CAISO accepts Bids and Inter-SC Trades for Energy, Ancillary Services and other commodities from SCs that are certified to transact through CAISO

How CAISO ensures that those Bids and Inter-SC Trades are valid and modifies the Bids for correctness when necessary

How CAISO enters the Bids and Inter-SC Trades from SCs into a database for processing by other components of CAISO’s business systems

How CAISO provides feedback to SCs concerning Bids and Inter-SC Trades that are submitted

Detailed Bid validation rules are referenced in Attachment A of this BPM.

8.1 Timeline

This section presents the timelines for the DAM, and RTM as they relate to Bid submission and validation. DAM is for both physical Bids and Virtual Bids.

Exhibit 8-2 Time-Line for Bid Submission

<table>
<thead>
<tr>
<th>Stages</th>
<th>Day-Ahead Timeline</th>
<th>Real-Time Timeline</th>
<th>Activities</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Up to seven days prior to the Trading Day SC may begin submitting Bids</td>
<td>Beginning at approximately 1:00 pm the day prior to the Trading Hour SCs may begin submitting RTM bids for all 24 hours of the RTM for the following trading day</td>
<td>SCs continuously submit bids before Market Close time to CAISO. CAISO validates bids upon receipt and provides messages back to SCs as to the validity of their bids referencing specific validation rules that have fired on their bids. Master-file data is updated on a daily basis. All affected DAM bids are revalidated based on new master file data.</td>
</tr>
<tr>
<td>2</td>
<td>10:00 am</td>
<td>T- 75</td>
<td>The DAM and RTM are closed for bid submission CAISO performs any necessary bid generation All market accepted bids with a status</td>
</tr>
<tr>
<td>Stages</td>
<td>Day-Ahead Timeline</td>
<td>Real-Time Timeline</td>
<td>Activities</td>
</tr>
<tr>
<td>--------</td>
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</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>of Modified or Valid are considered Clean Bids and sent to IFM/RTM to continue processing the markets.</td>
</tr>
</tbody>
</table>

### 8.1.1 Day-Ahead Market

Day-Ahead Market Bids may be submitted up to seven days prior to the Trading Day for each of the seven days when the DAM opens and must be submitted prior to Market Close for each Trading Hour in the Trading Day, at 1000 hours of the day prior to the Trading Day.

In the DAM, SC submits a Day-Ahead Bid for a resource for a 24-hour market period. The Day-Ahead Bid comprises two types of components:

**Daily Components** – These are physical Bid parameters that are associated with the resource for the Trading Day, not with an individual market or hourly intervals of the physical Bid and are not applicable to Virtual Bids. Daily components include:

- Start-Up information (Cost curve, time curve)
- Minimum Load information
- Transition Information (Multi-Stage Generating Resources only)
- Ramp Rate information
- Minimum and Maximum Energy Limit information
- Initial State of Charge (SOC)

**Hourly Components** – These are physical Bid parameters that may vary from one Trading Hour to the next through the Trading Day. Hourly components are not applicable for Virtual Bids except as noted below:

- RUC Availability Bid price
- RUC Availability Bid quantity
- Capacity Limit Indicator
- Ancillary Services quantities
- Ancillary Services Bid prices
- Contingency Dispatch information
- Self-Provision quantities
- Energy Bid Curve (Virtual Bids consist of only the Energy Bid Curve)
- Demand Bid curve
- Pump Shut-Down and Pumping Cost information
- Pumping Level
- Distribution Location and Factors (for a Generating Unit that consists of multiple individual Generating Units)

### 8.1.2 Real-Time Market

The RTM for a given Trading Hour opens after the DAM results are published for the Trading Day that includes the relevant Trading Hour (by 1300 hours of the day before the Trading Day) and closes 75 minutes before the start of that Trading Hour. RTM Bids are submitted for one-hour periods (the Trading Hour) of the Trading Day.

The daily and hourly components of the Bid are the same as for the DAM. If daily components are submitted for a Generating Unit with the Day-Ahead Market Bid, the SC does not need to submit this data again for the RTM.

### 8.2 Energy Bid Validation Rules

This section is based on the following CAISO Tariff sections:

- CAISO Tariff Section 30.7, Bid Validation
- CAISO Tariff Section 30.10, Format and Validation of Operational Ramp Rates
- CAISO Tariff Section 30.11, Format and Validation of Startup and Shutdown Times
- CAISO Tariff Section 30.12, Format and Validation of Startup and Shutdown Costs
- CAISO Tariff Section 30.12, Format and Validation of Minimum Load Costs
- CAISO Tariff Section 30.7.3.6.2 Credit Requirement

CAISO validates all Energy Bids submitted by SCs prior to carrying out any of the market processes. Bids are validated for content and for consistency with the Registered Data contained in the Master File. In addition Virtual Bids are validated for available credit with the Credit Tracking System. For physical Bids, the rules can also generate Bids for any missing or invalid data. The same basic approach to Bid validation takes place for the DAM and the RTM, with one additional step in the DAM to validated Bids against updated Master File content. CAISO carries out Bid validation in four steps:
Step 1: CAISO validates all Bids after submission of the Bid for content, which determines that the Bid adheres to the structural rules required of the Bid (as described in more detail in Section 8.2.4). If the Bid fails any of the content level rules, CAISO assigns the Bid a status of “Rejected Bid” and the SC has the opportunity to correct and re-submit the Bid.

Step 2: After the Bids are successfully validated for content, but prior to the Market Close of the DAM, CAISO carries out the second level validation rules to verify that the Bid adheres to the applicable CAISO Market rules and if applicable, limits based on the content of the Master File. If the Bid fails any level two validation rules, CAISO assigns the Bid a status of “Invalid” and the SC has the opportunity to correct or resubmit the Bid.

Step 3: Physical Bids Only - If the Bid successfully passes validation in Step 2, it continues through the third level of processing where CAISO analyzes the Bid based on its content, to identify any missing Bid components that must be present for the Bid to be valid consistent with the market rules. At this stage, the Bid is either automatically modified for correctness and assigned a status of:

- “Conditionally Modified” or “Valid”

Step 4: Virtual Bids Only - If the Virtual Bid successfully passes validation in Step 2, it is passed on to the Credit Tracking System where it will be validated against available credit, if Approved the assigned Bid status will remain as “Conditionally Valid” or “Valid”, if Disapproved, the assigned Bid status will be set to “Invalid”.

Virtual Bid position limits exist at each location and are associated to a Convergence Bidding Entity which may have multiple Scheduling Coordinators authorized to submit Virtual Bids at each location. Bidding validation rules are triggered each time a Virtual Bid is submitted, if the sum of all bids at that location by the Scheduling Coordinators associated to a single Convergence Bidding Entity exceeds the Position Limit, all bids at that location for that Convergence Bidding Entity will become Invalid.

Physical Bids that trigger bidding validation rules that result in warnings do not result in an invalid or rejected Bid status but simply notify the user of an issue with the Bid that they have submitted. SCs will need to take action on warnings to ensure their Bids or Trades will be accepted for a particular market.
Bids submitted in advance of the DAM are revalidated after the daily Master File update. After the update, all conditional Bids must be re-validated prior to the trading period when the Bid takes effect. After Market Close for the DAM or RTM, to the extent that SCs fail to enter a Bid for certain resources that are required offer RA capacity, CAISO creates Energy Bids for these resources, called a Generated Bid. After Market Close for the DAM the CAISO also creates required $0 RUC Availability Bids for certain resources as well as the AS bids for those resources. For resources that are subject to CAISO Tariff Appendix II, CAISO will replace submitted Energy Bids (which must be at $0/MWh) with a Generated Bid. Except for bids created by the CAISO, an SC can cancel a Bid any time prior to Market Close by selecting the “Cancel” button on the Bid summary page of the SIBR application or by submitting the Web Action message through web services.

NOTE: In order to allow for sufficient time to resolve any possible validation/balancing issues before closing of a Market, Bids, including Self-Schedules, should be submitted within 30 minutes of Market Close.

Warnings or rejections are issued in the following cases:

- Wheeling Through transactions that are not matched (Balance Indicator is “N”, meaning that there is no matching Wheeling Reference for either the Import or Export bid in the Wheeling Bid Component). Such Bids will be erased if the wheeling reference does not match.
- Inter-SC Trades without matching counterparties are deemed invalid at market close time.
- Trades with circular dependencies are deemed invalid at market close time.
- ETC or TOR Self-Schedules that are not balanced upon submission into SIBR, for DAM only, will lose its scheduling priority for the entire ETC or TOR Self-Schedules. The CAISO will apply the ETC or TOR Settlement treatment pursuant to Tariff section 11.2.1.5 to the valid balanced portions only, for DAM and RTM.
- ETCs or TOR Self-Schedules that exceeds the resource capacity limits in the relevant Existing Contract based on TRTC instructions will be rejected upon submission into SIBR, and the responsible SC will be notified.
- ETCs or TOR that are submitted when their Entitlement is not positive will be rejected upon submission into SIBR, and the responsible SC will be notified.
- ETC or TOR Self-Schedules that do not reference the correct Contract Reference will be rejected upon submission into SIBR, and the responsible SC will be notified.

NOTE: Individual ETCs and TORs may be part of a chain (a combination of individual TORs or ETCs used in sequence). Each submission of an ETC or TOR Self-Schedule
that is part of a chain will trigger notification to ALL Scheduling Coordinators associated with the registered chain.
Detailed steps that CAISO validation processes are outlined in Sections 8.2.1 to 8.2.3

8.2.1 Day-Ahead Market Validation

CAISO’s DAM validation includes validation steps prior to the close of the market, including the update to Master File.

8.2.1.1 Physical Bid Validation Prior to Market Close & Master File Update

Exhibit 8-1 below outlines the steps CAISO takes to validate Physical Bids prior to Market Close and Master File update.
Exhibit 8-1: Bid Validation Prior to Market Close

- Bid Creation
  - Created Bid
- Bid Submission
  - Submitted Bid
- Bid Content
  - Pass
  - Fail
- Accepted Bid
- Bid Validation
  - Pass
  - Fail
- Temporarily Valid Bid
- Bid Processing
  - Pass
  - Fail
- Conditionally Valid Bid
- Bid Modification
  - Conditionally Modified Bid
- Bid Re-submission
  - Obsolete Bid
- Bid Cancellation
  - Canceled Bid
1) **Bid Creation** – SCs create Bids, entering all required data.

2) **Bid Submission** – SCs submit Bids into the SIBR platform.

3) **Level 1: Bid Content Validation** – After the SC submits a Bid, CAISO rules engine performs a Bid content validation, to verify that the Bid is structurally complete and correct. In this step, CAISO evaluates whether the Bid adheres to all the “structural rules” required of Bids. This includes such things as validating that all required components are present and the resources or services contained in the Bid actually exist. References to the Bidding rule details are in Attachment A of this BPM.

4) **Bid Acceptance** – If the Bid passes the Bid content validation in Step 1, CAISO categorizes the Bid as an “Accepted Bid”. If the Bid fails any of the content validation rules, CAISO assigns the Bid a “Rejected Bid” status. The SC must correct and re-submit the Bid.

5) **Level 2: Bid Validation** – All Accepted Bids undergo Bid validation for the entire Trading Day immediately after Bid submission to ensure all Bid contents are present and valid. Accepted Bids that fail Bid validation become Invalid Bids and Accepted Bids that pass Bid validation become Temporarily Valid Bids. This Bid is then eligible to be used in the Markets. CAISO remembers any errors and informs the SC that validation is complete, and provides the error analysis to the SC. If the validation fails, the Bid becomes an “Invalid Bid” and the SC must correct and re-submit the Bid. CAISO validates that the components of the Bid meet the applicable market rules. e.g., the Bids are a) consistent with the contents of the Master File; and b) for RTM Bids, consistent with the Schedule and Award from the Day-Ahead Market. If the Bid passes CAISO validation, CAISO characterizes the Bid as a “Temporarily Valid Bid”.

Note for Multi-Stage Generating Resource bids: If any configuration within a bid does not pass Bid Content or Bid Validation all configurations submitted as part of the bid will also become Rejected or Invalid. Warning messages will indicate which configuration caused the bid to become Rejected or Invalid.

6) **Level 3: Bid Processing** – The Bid is only processed (or modified for correctness) if it at least passes through all content and validation rules, which means that the Bid submitted is structurally correct and conforms to all Master File parameters. Once a Bid passes through the content and validation rules, it
may be modified if it violates any of the processing rules. CAISO analyzes the “Temporarily Valid Bid” to identify any missing Bid components that must be present for the Bid to be valid. CAISO either modifies the Bid for correctness and assigns it a status of “Conditionally Valid Bid” or modifies the Bid and assigns it a status of “Conditionally Modified Bid”. The detailed Bid processing rules are referenced in Attachment A of this BPM. At this point the SC may leave the bid unchanged or initiate a change as follows:

a) Cancel the Bid, in which case CAISO retains the Bid in the system as a “Cancelled Bid”. CAISO does not process Cancelled Bids.

b) Modify and re-submit the Bid, in which case CAISO retains the original Bid in the system as an “Obsolete Bid”. CAISO does not process Obsolete Bids. The re-submitted Bid is processed as a new Bid, starting with Level 1, content validation. If the new Bid is Invalid or Rejected, the current Valid or Modified Bid remains active in the designated market.

c) If the SC does not want to make any changes to their existing Bid, they may leave the Conditionally Modified Bid or Conditionally Valid Bid as is to be processed in the appropriate CAISO Market.
7) **Bid Status** – Summary of how Bid Status changes.

![Bid Status Diagram](image)
8.2.1.2 Virtual Bid Validation Prior to Market Close and Master File Update

1) Bid Creation – SCs create Virtual Supply and Demand Bids, entering all required data.

2) Bid Submission – SCs submit Bids into the SIBR platform.

3) Level 1: Virtual Bid Content – After the SC submits a Bid, CAISO rules engine performs a Bid content validation, to verify that the Bid is structurally complete and correct. In this step, CAISO evaluates whether the Bid adheres to all the “structural rules” required of Bids. This includes such things as validating that all required components are present and the resources or services contained in the Bid actually exist. Please refer to the Bidding rule details that are in Attachment A of this BPM.

- Virtual Bid Acceptance – If the Bid passes the Bid content check the CAISO categorizes the Bid as a temporarily valid and passed to through to the next set of rules for step 2. If the Bid fails any of the content rules, CAISO assigns the Bid a “Rejected” status. The SC must correct and re-submit the Bid.

4) Level 2: Virtual Bid Validation – All Bids that pass the content check in Step 1 undergo Bid validation for the entire Trading Day, Bids that fail validation become an “Invalid Bid” and the SC must correct and re-submit the Bid. If the Bids are consistent with the contents of the Master File the Bid passes CAISO validation, CAISO characterizes the Bid as a “Conditionally Valid” or “Valid”.

5) Level 3: Virtual Bid Credit Approval Processing – Only a “Conditionally Valid” or “Valid” Bid will be sent to the Credit Tracking System for credit approval. Depending on the available credit for the Convergence Bidding Entity a credit status for the Bid will be returned as “Approved” or “Disapproved”, A credit status returned as “Approved” will retain the Bid status of either “Conditionally Valid” or “Valid”. If the credit status is returned as “Disapproved” then the Bid status will be set to “Invalid”. The detailed Bid processing rules are referenced in Attachment A of this BPM. At this point the Scheduling Coordinator may leave the bid unchanged or initiate a change as follows:

a) Cancel the Bid, in which case CAISO retains the Bid in the system as a “Cancelled Bid”. A cancelled bid will be sent to the Credit Tracking System for a release of the credit.
b) Modify and re-submit the Bid, in which case CAISO retains the original Bid in the system as an “Obsolete Bid”. Obsolete bids will be sent to the Credit Tracking System for credit release prior to the modified bid being sent to the Credit Tracking System. If the new Bid is Invalid or Rejected, the current Valid or Conditionally Valid Bid remains active in the designated market.

If the SC does not want to make any changes to their existing Bid, they may leave the “Conditionally Valid” or “Valid” Bid as is to be processed in the appropriate CAISO Market.

Exhibit 8-2 below outlines the steps CAISO takes to validate Virtual Bids prior to Market Close and Master File update.
Exhibit 8-2: Bid Validation Prior to Market Close

- Created Bid
  - Submitted Bid
    - Bid Content
      - Level 1 Content Check
        - Fail: Rejected Bid
        - Pass: Temporarily Valid
      - Bid Validation
        - Level 2 Validation Check
          - Fail: Invalid Bid
          - Pass: Valid Bid
            - Bid Re-submission
            - Bid Cancellation
              - Obsolete Bid
              - Canceled Bid
            - Credit Release
          - Approved
          - Disapproved
8.2.1.3 SIBR Generated Bid (Physical Bids only)

In the event that SIBR must generate a Bid or Bid component to comply with Tariff requirements, SIBR will generate a Bid or Bid component for the resource. There is a series of processing rules that are executed to establish the Start-Up and Minimum Load Cost in SIBR to generate the Bid with the proper Start-Up and Minimum Load costs based on the resource’s election of either the Proxy Cost Option or the Registered Cost Option, and if it is a Natural Gas resource or Non-Natural Gas resource. Registered Cost resources use the values provided for the resource that are in the Master File.

Resources that are subject to CAISO Tariff Appendix II must select the Proxy Cost Option for Start-Up and Minimum Load costs. The SIBR Rules (Appendix A) sections 411xx (Generating Resource Start-Up Bid Component Processing) and 412xx (Generating Resource Minimum Load Cost Bid Component Processing) detail the generation of these costs.

Start-Up Bid Component

If the Registered Cost Option is selected, a Registered Start-Up Cost will be generated. See Attachment G for details.

If the Proxy Cost Option is selected, the following two curves will be generated for a Start-Up Bid component if the Scheduling Coordinator has not submitted a Start-Up Bid component, or if the submitted Start-Up Bid component is higher than the proxy cost:

1. The Start-Up Time Bid Curve - this is the registered value retrieved from Master File for the resource and most current Trading Day.

2. The Start-Up Cost Curve - this is calculated using the following information:
   c. Greenhouse Gas Start-Up Cost Allowance Curve (if applicable – see Attachment K for details).
   d. Major Maintenance Start-Up Cost Adder (if applicable – see Attachment L for details).
   e. Grid Management Charge (GMC) Start-Up Cost Adder (Minimum Load * GMC Adder * (shortest Start-Up Time/60) *.5). The GMC Adder is made up of the Market Services Charge and System Operations Charge components.

For examples of a Start-Up Bid component calculation, see Attachment G.

**Minimum Load Cost Component**

If the Registered Cost Option is selected, a Registered Minimum Load Cost will be generated. See Attachment G for details.

If the Proxy Cost Option is selected, the Minimum Load Cost is generated using the following information if the Scheduling Coordinator has not submitted a Minimum Load Cost bid, or if the submitted Minimum Load Cost bid is higher than the proxy cost:

1. Minimum Load Fuel Cost – the product of the Minimum Load Heat Rate, the Minimum Load, and the daily Gas Price Index.

2. Operation and Maintenance Minimum Load Cost - the product of the registered Operation and Maintenance Cost and the registered Minimum Load. Alternatively, a custom O&M adder may be negotiated with the CAISO or the Independent Entity.


4. Major Maintenance Minimum Load Cost Adder (if applicable – see Attachment L for details).

5. Grid Management Charge (GMC) Minimum Load Cost Adder - product of the GMC Minimum Load Cost Adder and the registered Minimum Load. The GMC Minimum Load Cost Adder is made up of the Market Services Charge and System Operations Charge components and a third value representing the Bid Segment Fee component divided by the resource Pmin.


For examples of a Minimum Load Cost Component calculation, see Attachment G.

**Energy Bid Component**
An Energy Bid will be generated as provided in accordance with the CAISO’s SIBR rules using the following information if the Scheduling Coordinator has not submitted an Energy Bid:

1. Energy cost curve – product of the incremental heat rate curve multiplied by the Gas Price Index.

2. Operation and Maintenance (O&M) cost - specified in Exhibit 4-2. Alternatively, a custom O&M adder may be negotiated with the CAISO or the Independent Entity.

3. 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 component divided by the bid segment MW size.

Energy Bid curve = energy cost curve + O&M cost + GMC adder.

Below is an example of how the Bid is generated for Generating Units and Resource Specific System Resources. Additional examples are contained in Attachment F. For non-Resource Specific System Resources, please see Appendix Attachment I.

**Bid Curve Generation Example**

The Generating Unit in the following example is registered as a natural gas resource. The following registered Master File data is used in the example. These values are for illustrative purposes only:

<table>
<thead>
<tr>
<th>Operating Levels</th>
<th>Average Heat Rate</th>
<th>Gas price index</th>
<th>Operation &amp; Maintenance Cost</th>
<th>Grid Management Charge adder</th>
</tr>
</thead>
<tbody>
<tr>
<td>70</td>
<td>14440</td>
<td>$5.5</td>
<td>$2.80</td>
<td>$0.50</td>
</tr>
<tr>
<td>150</td>
<td>11960</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>300</td>
<td>10909</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>485.17</td>
<td>10366</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**1) Generated Energy Curve Calculation**

The generated Energy Curve is calculated as the sum of the Incremental Fuel Cost curve (calculated in section 3 and 4 below), the registered Operation and Maintenance Cost ($/MWh), and the GMC adder.

\[
\text{Segment 1} = (53.85 + 2.80 + 0.50) = \$57.15
\]

\[
\text{Segment 2} = (54.22 + 2.80 + 0.50) = \$57.52
\]

\[
\text{Segment 3} = (52.17 + 2.80 + 0.50) = \$55.47
\]
The resulting Energy Curve is:

- 70MW – 150MW @ $57.15
- 150MW – 300MW @ $57.52
- 300MW – 485.17MW @ $55.47

The Generated Energy curve must be adjusted to be monotonically increasing. If a Generated Energy Bid Curve is not monotonically increasing, CAISO adjusts the Energy Bid price of each Energy Bid segment after the first one, to the previous Energy Bid segment, if higher, and the two Energy Bid segments are merged in the Energy Bid Curve

2) Final Generated Energy Curve

70MW - 150MW @ 57.15
150MW – 485.17 MW @ 57.52

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

3) Incremental Fuel Cost Curve Calculation

The Incremental Fuel Cost Curve used to derive the Energy Bid Curve must be calculated as the product of the Incremental Heat Rate Curve and the registered Gas Price Index ($/MMBtu) for that Trading Hour and the Generating Resource specified in that Bid, if that Generating Resource is registered as a Natural Gas Resource for that Trading Hour.

- Segment 1 - 9790/1000 * 5.5 = 53.85
- Segment 2 – 9858/1000 * 5.5 = 54.22
- Segment 3 – 9486/1000 * 5.5 = 52.17

4) Incremental Heat Rate Calculation

The Incremental Heat Rate of the Incremental Heat Rate Curve segment between two Operating Levels is calculated as the ratio of the difference between the product of the registered Average Heat Rate at the higher Operating Level times that Operating Level, minus the product of the registered Average Heat Rate at the lower Operating Level times that
Operating Level, over the difference between the higher Operating Level and the lower Operating Level

Segment 1 – \(\frac{(11960 \times 150) - (14440 \times 70)}{150 - 70} = 9790\)

Segment 2 – \(\frac{(10909 \times 300) - (11960 \times 150)}{300 - 150} = 9858\)

Segment 3 – \(\frac{(10366 \times 485.17) - (10909 \times 300)}{485.17 - 300} = 9486\)

5) Minimum Load Cost Calculation

\[\text{Minimum Load Cost} = \text{Minimum Load Fuel Cost} + (\text{O&M} \times \text{Minimum Operating Level}) + \text{Greenhouse Gas Allowance Minimum Load Cost} + \text{Major Maintenance Minimum Load Cost Adder} + \text{GMC Minimum Load Cost Adder}\]

6) Transition Cost Calculation - See Attachment H of this BPM for details.

8.2.1.4 Master File Data Update

Since DAM Bids may be submitted up to seven days in advance they must be revalidated daily based on the daily update of Master File information. The Master File used in SIBR is consistent with the updated Master File for that Trade Day. The Master File can be refreshed daily and can be used for bids submitted up to \(t + 7\). However, when the Master File refreshes the next day bids that were initially valid may become invalid or rejected based on new Master File data. If a resource changes ownership, the new owner will not be able to input bids or schedules on the resource until the Master File has refreshed for that day.

Bids are assigned a “Conditional” status during the initial Bid validation since the Bid status could change with the update of the Master File information. These Bids are assigned a status of “Conditionally Modified” Bid or “Conditionally Valid” Bid until the final Master File update occurs for the Trading Day designated in the Bid.

The diagram in Section 8.2.1.5 below shows the validation process a Bid goes through when it is in a “Conditional” state. Changes to the Master File for each SC that were submitted at least seven business days in advance are introduced into the system once per day.

8.2.1.5 Physical Bid Validation Prior to Market Close & After Final Master File Update for Trading Day

Exhibit 8-3 shows the steps CAISO uses to validate Physical Bids after Master File update and prior to Market Close.
After the Master File is updated by CAISO, CAISO re-validates all “Conditional” Bids using the following process:

1) CAISO validates the “Conditionally Valid Bids” and the “Conditionally Modified Bids” to establish that the Bids meet the applicable market rules. If the Bid passes the validation process, the Bid becomes a “Temporarily Valid Bid”. If the Bid does not pass the validation process, the Bid becomes a “Rejected Bid”.

2) CAISO processes the “Temporarily Valid Bid” (using CAISO Market Rules), and either accepts the Bid as submitted, to produce a “Valid Bid” or modifies the Bid to produce a “Modified Bid”.

3) The SC reviews the “Valid Bid” or “Modified Bid”. At this time the SC may re-submit the Bid (all validation and Bid processing steps are repeated for the new Bid), cancel the Bid or allow the Bid to stand.

4) The SC may also review the “Ind Viewer” tab on the UI at any time to check the balance and priority indicators for ETC/TOR and Wheel bids that were submitted for specified resources.

At the time of Market Close, the “Valid Bid” or “Modified Bid” becomes a “Clean Bid”.
8.2.1.6 Virtual Bid Validation Prior to Market Close & After Final Master File Update for Trading Day

After the Master File is updated by CAISO, CAISO re-validates all “Conditional” Bids using the following process:

1) CAISO validates the “Conditionally Valid Bids” to establish that the Bids meet the applicable market rules. If the Bid passes the content check, the Bid becomes a “Temporarily Valid Bid”. If the Bid does not pass the validation process, the Bid becomes a “Rejected” Bid.

2) CAISO passes the temporarily valid through to the Level 2 validation where the bid passes CAISO validation, CAISO characterizes the Bid as a “Conditionally Valid” or “Valid” or if the Bid fails validation it will become an “Invalid Bid” and the SC must correct and re-submit the Bid.

3) The SC reviews the “Valid Bid”, at this time the SC may re-submit the Bid (all validation and Bid processing steps are repeated for the new Bid), or cancel the Bid or allow the Bid to stand.

4) The SC may also review the “Limit Viewer” tab on the UI at any time to see if any changes may have affected any position limits associated to a location associated to an Inter-Tie scheduling point specified in a bid.

5) Virtual Bidding may be suspended or limited by the CAISO either by SC, Location, or Convergence Bidding Entity at a Location to adjust Position Limits. These actions are supported by Tariff section 39.11.2.

Exhibit 8-4 shows the steps CAISO uses to validate Virtual Bids after Master File update and prior to Market Close.
Exhibit 8-4: Virtual Bid Validation After Final Master File Update and Prior to Market Close

At the time of Market Close, the “Valid Bid” becomes a “Clean Bid”.

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8.2.1.7 Validation After Market Close (Not applicable to Virtual Bids)

If an SC fails to submit a Bid for the full amount of available RA Capacity from a Generating Unit or Dynamic System Resource (Resource Specific System Resource) other than Use-Limited and Hydro Resources, CAISO creates an Energy Bids for these resources, called Generated Bids. CAISO creates Generated Bids after Market Close for the DAM using data in the Master File or through data provided by the applicable SC. CAISO notifies the SC of the use of a Generated Bid for each Generating Unit prior to Market Clearing of the IFM.

The Generated Bid is provided to the SC. The SC may view the Generated Bid but may not modify the Generated Bid.

8.2.2 Open / Isolated Intertie Validation

The ISO market systems will validate all System Resources Bids, including Self-Schedules, for each Trading Hour with regard to open or isolated Intertie conditions on associated Intertie constraints (ITC) and market scheduling limits (MSL). This validation is based on the directional total transfer capability (TTC) and the isolated Intertie status reported by the Existing Transmission Contract Calculator (ETCC) on the ITCs / MSLs.

Section 30.8 prohibits Scheduling Coordinators from submitting Bids, including Self-Schedules, on transmission paths that are out-of-service, i.e., the transmission TTC is rated at zero. These open Intertie conditions occur when the TTC is zero in both directions of the Intertie or path. If Scheduling Coordinators submit Bids at such locations, the Section 30.8 requires that the ISO reject such Bids or Self-Schedules. An isolated Intertie condition is one where the TTC is non-zero in one direction, but that TTC is reserved for resources registered as stranded load in the master file.

Under open Intertie conditions, all associated resource Bids are marked as inadmissible during the hours where the condition exists. Under an isolated Intertie condition, all associated resource Bids are marked as inadmissible, during the hours where the condition exists, except resources registered as stranded load in the direction of the non-zero TTC. In either case, inadmissible Bids are ignored in the market applications (DAM/RTN), thereby rejected by the applicable market run. While the ISO markets ignore inadmissible Bids and in effect rejecting these Bids, these Bids are not rejected or modified as are bids that fail other validation rules. Rather, an hourly indicator in the Bid indicates that the Bid is inadmissible due to open/isolated Intertie conditions. This hourly indicator is displayed on the graphical user interface for each hourly Bid component. Additionally, the Bid processing rules that determine this indicator are displayed in the defined error messages and returned in an API per rule error message.
Bids for System Resources which have registered an alternate tie path in the Master File will be considered in the IFM to be bid at the alternate path if the primary tie path is open or isolated. For these resources, if both the primary and alternate path is open / isolated, only then will the bid be considered inadmissible for the ISO market processes.

8.2.3 RTM Validation

CAISO uses the same process to validate Bids for the RTM, with the exception that CAISO does not validate the Bid before and again after the Master File update. CAISO only validates the RTM Bids based on the current Master File Data on the relevant Trading Day.

8.2.4 Validation Process

The Bid validation process is divided into three categories:

- Bid Content
- Bid Validation
- Bid Processing

The detailed rules used in the validation process are referenced in Attachment A of this BPM.

All Bid processing rules are specific to the Bid component and are described in the relevant sections of Appendix A.
9. **Inter-SC Trades**

Welcome to the *Inter-SC Trades* section of the CAISO *BPM for Market Instruments*. In this section you will find the following information:

A description of Inter-SC Trades of Energy and the timeline for submittal, and the validation rules for this type of Inter-SC Trade

A description of Inter-SC Trades of Ancillary Service capacity

A description of Inter-SC Trades of IFM Load Uplift Obligation

CAISO facilitates Inter-SC Trades (ISTs) of Energy, Ancillary Services, and IFM Load Uplift Obligation through the settlement process. ISTs do not have any impact on the scheduling or dispatch of resources. They affect only the financial settlement process. Only trades that SCs want to settle through CAISO are submitted in the IST process.

### 9.1 **Inter-SC Trades of Energy**

This section is based on CAISO Tariff Section 28.1, Inter-SC Trades of Energy.

CAISO facilitates ISTs of Energy. These Inter-SC Trades comprise two types:

**Trades at Aggregated Pricing Nodes that are also Defined Trading Hubs or LAPS (APN)** – Where the Inter-SC Trade is not backed by a physical resource. The CAISO will facilitate ISTs (APN) only at defined Trading Hubs and Default LAPS.

**Physical Trades** – Where the Inter-SC Trade is backed by a physical resource.

An IST of Energy is defined as

An Energy quantity (MWh)

Traded from one SC to another SC

For a specific hour, trade Location, and market (e.g., DAM or RTM)

For a specific type of Inter-SC Trade – Physical Trade (PHY), Aggregate Pricing Nodes (APN), Converted Physical Trade (CPT)

ISTs for Energy can take place in both the DAM and RTM. ISTs of Energy submitted for the DAM are settled at the applicable LMPs at the Aggregated Pricing Nodes or at the Pricing Node
specified in the IST. ISTs of Energy submitted in the RTM are settled hourly based on the simple average of the Dispatch Interval LMP at the applicable Aggregated Pricing Node or the Pricing Node specified in the IST.

9.1.1 Timeline

Inter-SC Trades for the Day-Ahead Market may be submitted beginning seven days prior to the Trading Day up to 1200-11:00 hours the day prior to the Trading Day. Inter-SC Trades for the Real-Time Market may be submitted beginning at midnight the day prior to the Trading Hour up to 45 minute prior to the Trading Hour.

The timeline for submission and validation of Energy IST is shown in Exhibit 9-1.

<table>
<thead>
<tr>
<th>Stages</th>
<th>Day-ahead Timeline</th>
<th>Real-time Timeline</th>
<th>Activities</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Up to seven days prior to the Trading Day Only ISTs for Energy (both PHY and APN) are submitted into the DAM.</td>
<td>Beginning at 12:00 a.m. the day prior to the Trading Hour ISTs for Energy (APN and PHY) as well as ISTs for Ancillary Services and IFM Load Uplift Obligation are submitted.</td>
<td>SCs continuously submit ISTs before Inter-SC Trade Close Time and Bids before Market Close time to CAISO. CAISO continuously screens each submitted IST to check contents and search for matching IST submitted by the counterparty SC. CAISO performs pre-market validation to evaluate and adjust PHYs if necessary, based on Generator Unit Energy Bids at pre-specified time intervals (e.g., every 20 minutes, and at the Inter-SC Trade Close Time). CAISO provides feedback to the SCs about the validity of the ISTs based on the information that is available to CAISO at that time.</td>
</tr>
<tr>
<td>2</td>
<td>Between 0600 hours and 1200-11:00 hours of the day prior to the Trading Day.</td>
<td>Between T-180 and T-45 min (the Inter-SC Trade Close Time for IST submission in the RTM)</td>
<td>SCs continuously submit ISTs before Inter-SC Trade Close Time and Bids before Market Close time to CAISO. CAISO continuously screens each submitted IST to check contents and search for matching IST submitted by the counterparty SC. CAISO provides feedback to the SCs regarding the validity of the ISTs based on the information that is available to CAISO at that time.</td>
</tr>
</tbody>
</table>
### Stages Day-ahead Timeline Real-time Timeline Activities

| 3 | 1300 hrs (approximately) | At T-47 min (approximately) | CAISO performs post-market validation of the ISTs based on the IFM or RTM results, and converts invalid portions of PHYs to Converted Physical Trades. The timing of this event is dependent on the receipt of the Market Results (DA/RT). |

During the Day-Ahead IST Trading period (which closes at **1200-11:00** hours), CAISO notifies SCs if their submitted IST does not have a counterparty. At **1200-11:00** hours, CAISO rejects any ISTs for the Day-Ahead Market that do not have a matching counterparty. For PHYs, CAISO adjusts the quantity of ISTs if necessary, based on the Generating Unit Bid in the DAM, on which the PHY is dependent. (Note: For Multi-Stage Generating Resources that may be used in a PHY Trade as the location, the maximum quantity of the Energy Curve or Self-Schedule on the highest Configuration will be used in the validation for the PHY Trade).

Beginning at **0600** hours CAISO conducts pre-market validation on PHYs based on the Bids reflecting the dependent Generating Unit. SCs are sent warnings if necessary that their Inter-SC Trades may be adjusted at the close of the market. PHY Trades that are not supported by a market accepted bid will be adjusted to 0. Pre-market validation continues to run every 20 minutes until Inter-SC Trade market close time of **1200-11:00** hours.

When the DAM clears, at approximately **1300** hours, CAISO conducts a post-market validation on Day-Ahead PHYs, based on the final DAM results from the IFM. Any portion of a PHY, where the dependent Generating Unit’s final Day-Ahead Schedule is less than the PHY trade amount becomes a Converted Physical Trade (CPT). CAISO informs the SC of the amount of the CPT.

SCs may submit Inter-SC Trades for the RTM from **0000** hours of the day prior to the Trading Day up to 45 minutes prior to Market Close (Real-Time IST Trading Period). During the Real-Time IST Trading Period, CAISO validates the ISTs for content as well as searching for the matching IST submitted by the designated counterparty. Beginning at **T-180** up until **T-45**, CAISO conducts pre-market validation every 20 minutes based on the Bid reflecting the Generating Unit. SCs are warned that their Inter-SC Trades may be adjusted at the close of the market. At **T-45**, CAISO rejects any Inter-SC Trades that do not have a matching counterparty.

CAISO conducts a post-market validation using the HASP advisory awards once the RTM has closed. Any invalid quantities where the dependent Generating Unit’s Real-Time Dispatch Instructions do not cover the PHY amount becomes a CPT. CAISO informs the SC of the amount of the CPT.
Example of PHY Trade Validation (simplified):

**Trade A**  PHY Trade Qty = 100MW (using a resource “Res_1” as the location).

**Res_1** has a Bid/Schedule = 80MW

Pre-cyclic validation runs to see the 80MW submitted and adjusts the **“Trade A”** PHY Trade Qty = 80MW.

Market results are returned to SIBR from IFM; “Res_1” clears with 50MW instead of the bid in 80MW.

Post-cyclic validation runs and now sees the 50MW award for “Res_1” and does the following:

Adjusts **“Trade A”** PHY Trade Qty = 50MW

Generates the CPT for **“Trade A”** Trade Qty = 30MW (difference between adjusted Trade Qty and IFM award with the Trading Location at the Trading Hub.

So the IFM Award of 50MW plus the generated CPT of 30MW = the Adjusted Trade quantity of the Pre-cyclic validation.

This works the same way for the RTM with the exception that during the Pre Cyclic Validation there is also a check for any DA Trade Qty on the PHY Trade using the Resource.

Using the example above as a result of the DA Trade where the PHY “Trade A” is awarded 50MW.

**“Trade A”** (RTM)  PHY Trade Qty = 50MW (using “Res_1” as the location).

**Res_1** has a Bid/Schedule = 80MW

Pre Cyclic Validation runs to see the 80MW submitted and also the DA Trade at that location for 50MW. So the bid = 80MW minus (-) the DA Trade at that location = 50MW results in an adjusted trade quantity for **“Trade A”** (RTM) PHY Trade Qty = 30MW.

It would then follow the same process for the Post Cyclic Validation to see if any CPT would be generated.
9.1.2 Information Requirements

This section identifies the information requirements for APN ISTs and PHY ISTs. It also presents the validations rules.

9.1.2.1 APN Inter-SC Trades

An SC submitting an APN IST submits the following information:

- ID of “From” SC
- ID of “To” SC
- IST Type – APN
- Trade Location – i.e., Trading Hub or Load Aggregation Point
- Trading Hour, Trading Day
- Market Type – i.e., Day-Ahead; Real-Time
- Quantity (MW)

9.1.2.2 Physical Inter-SC Trades (PHY)

An SC submitting a PHY IST submits the following information to CAISO:

- ID of “From” SC
- ID of “To” SC
- IST Name
- IST Type – PHY
- Trade Location – i.e., Generating Unit Location
- Trade Time period – i.e., Trading Hour, Trading Day
- Market Type – i.e., Day-Ahead; Real-Time
- Quantity (MW)
Depend on name – indicating either the name of the Inter-SC Trade on which the current Inter-SC Trade depends on, or the name of the Generating Unit if the generator that supports this PHY is scheduled by the “From” SC ID

9.1.2.3 Validation of IST of Energy

CAISO validates three aspects of the IST:

- Content
- Validation
- Processing

CAISO validates APNs for content and for a matching counterparty to the Inter-SC Trade prior to the Inter-SC Trade Close time. APNs that do not have a matching counterparty to the Inter-SC Trade at the Inter-SC Trade Close time are rejected by CAISO. CAISO notifies the SC of the rejection.

Exhibit 9-2 Validation Process for APN Trades
1) SCs submit APNs. APNs that pass the content validation process are deemed to be “Accepted” APNs.

2) Up until Inter-SC Trade Close time, CAISO searches for matching Inter-SC Trades with counterparty SC. When a match is found, the ISTs are deemed to be a “Matched” IST. Prior to Inter-SC Trade Close time, CAISO continues to search for matching IST and to ensure that any previously “Matched” IST do not become obsolete, due to changes in an IST submitted by a SC. If CAISO determines that a previously “Matched” IST is no longer matched, CAISO deems it to be an “Obsolete” IST.

CAISO validates PHYs prior to and after the CAISO Market clears. In the post-market confirmation of PHYs, CAISO determines whether SC’s PHY ISTs are supported (either directly or through an IST with another SC) by a transmission feasible Generating Unit scheduled at the same PNode that has scheduled energy that is equal to or greater than the amount of the IST.

Exhibit 9-3 describes the process CAISO uses to validate the PHY Inter-SC Trades. In addition to the steps used for APN Inter-SC Trade validation, CAISO carries out the following steps:

1) At the Inter-SC Trade Close time, CAISO validates that, for matched PHY Inter-SC Trades, there exists a valid dependent Inter-SC Trade, or physical resource with capacity greater than or equal to the capacity of the Inter-SC Trade. If CAISO does not find either a valid dependent Inter-SC Trade or physical Generating Unit, it designates the Inter-SC Trade as “Invalid”. Dependent PHYs must not form a circular relationship without a dependent Generating Unit. If CAISO identifies a circular relationship of PHYs, all PHYs involved in the circular relationship are deemed “Invalid” ISTs.

1) At the Inter-SC Trade Close Time, in the event that the capacity of a matched IST exceeds the capacity of the dependent Generating Unit or IST, CAISO adjusts the amount of the matched IST pro-rata. As noted above, the validation process for the RTM also considers the Day-Ahead PHY ISTs at the same location in determining the validation of RTM PHY ISTs. The pro-rata curtailed portions of PHY ISTs in this process are not settled by CAISO.

2) At Inter-SC Trade Close Time, CAISO determines that all un-matched or “Obsolete” IST are Invalid. All other matched PHY Inter-SC Trades remain classified as “Conditionally Valid” Inter-SC Trades.

3) CAISO validates PHYs after the market clears, to ensure that the amount of a PHY does not exceed the scheduled capacity of the Generating Unit, on which
the IST is dependent. If the capacity of the PHY exceeds the scheduled Energy of the Generating Unit, CAISO adjusts the amount of the PHY to match the scheduled quantity. Any reduction in quantity is converted to a Converted Physical Trade (CPT). At this time each IST is classified as either Modified or Valid.

**Exhibit 9-3: Validation Process for PHY Trades of Energy**

The Inter-SC Trade validation rules are referenced in more detail in Attachment A of this BPM.

It should be noted that in the event of a HASP failure and there is no data to validate PHY Trades at the close of the Trade Market the Final Trades will be generated as PHY Trades at the Adjusted Trade Quantity.

### 9.2 Inter-SC Trades of Ancillary Services Obligation

This section is based on CAISO Tariff Section 28.2, Inter-SC Trades of Ancillary Services.
SCs have an obligation to pay for AS. SCs may trade the financial obligation for Ancillary Services through an Inter-SC Trade. An Inter-SC Trade of Ancillary Services Obligation is an AS quantity (MW) traded from one SC to another SC for a specific hour and AS type. This is a financial transaction only – it does not allow the SC to trade the obligation to provide Ancillary Services.

Since CAISO charges a single system-wide user rate for each AS, Inter-SC Trades of Ancillary Services Obligation (AST) are settled by the system-wide user rate for the respective service for a specific Trading Hour, independent of markets (RTM or DAM). SCs therefore make a single AST for each Trading Hour. ASTs may be submitted in the RTM Inter-SC Trade Periods. ASTs may be submitted beginning at midnight the day prior to the Trading Hour up to 45 minute prior to the Trading Hour.

9.2.1 Types (Spinning Reserve, Non-Spinning Reserve, Regulation-Up, and Regulation-Down)

There are four types of AS that SCs can trade:

- Regulation Up
- Regulation Down
- Spinning Reserve
- Non-Spinning Reserve

9.2.2 Timeline

Inter-SC Trades of AS are submitted by SCs following the Real-Time Market timeline as described in Exhibit 9-4. ASTs may be submitted beginning at midnight the day prior to the Trading Hour up to 45 minute prior to the Trading Hour.

**Exhibit 9-4: Timeline of Inter-SC Trades of Ancillary Services**

<table>
<thead>
<tr>
<th>Timeline</th>
<th>Activities</th>
</tr>
</thead>
<tbody>
<tr>
<td>RTM Inter-SC Trade Period</td>
<td>SCs continuously submit ASTs in either Inter-SC Trade Period CAISO continuously screens each submitted AST to check contents and search for matching AST submitted by the counterparty SC. CAISO provides feedback to the SCs regarding the validity of the ASTs based on the information that is available to CAISO at that time.</td>
</tr>
</tbody>
</table>

9.2.3 Information Requirements

SCs submitting an AST must provide the following information
Submitting SC ID

From SC ID

To SC ID

AST Type – (Spinning reserve (SPT), Non-Spinning Reserve (NST), Regulation Up (RUT), Regulation Down (RDT))

Trade time period (Trading Hour)

Trading Day

Quantity (MW)

9.2.4 Validation of Inter-SC Trades Ancillary Services

CAISO validates ASTs using the following process:

1) SCs submit ASTs. ASTs that pass the content validation process are deemed to be “Accepted” ASTs.

2) Up until the time of Market Close, CAISO searches for matching ASTs with counterparty SC. When a match is found, the ASTs are deemed to be “Matched” ASTs. Prior to Market Close, CAISO continues to search for matching ASTs and to ensure that any previously “Matched” ASTs do not become obsolete, due to changes in an AST submitted by a SC. If CAISO determines that a previously “Matched” ASTs is no longer matched, CAISO deems it to be an “Obsolete” match.

3) At Trade Close Time, CAISO determines that all un-matched or “Obsolete” ASTs are Invalid. All other Matched ASTs are classified as “Valid” ASTs.

The Inter-SC Trade validation rules are referenced in Attachment A of this BPM.

9.3 Inter-SC Trades of IFM Load Uplift Obligation

(This section is based on CAISO Tariff Sections 6.5.4.1.2 and 28.2.3).

ISTs of IFM Load Uplift Obligation measured in MWh is the billing determinant for allocating the IFM Load Uplift Obligation to SCs. CAISO facilitates IST of this obligation between SCs. Similar to Inter-SC Trades of Ancillary Services, CAISO settles the IFM Load Uplift Obligation Trades
using a single system-wide user rate for a specific Trading Hour, independent of markets (RTM or DAM).

9.3.1 Timeline

Inter-SC Trades of IFM Load Uplift Obligation (UCT) are submitted by SCs following the RTM timeline as described in Exhibit 9-5.

**Exhibit 9-5: Timeline of Inter-SC Trade of IFM Load Uplift Obligation**

<table>
<thead>
<tr>
<th>Timeline</th>
<th>Activities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Submitted as early as 12:00 midnight on the Trading Day up to the close time of T-45.</td>
<td>SCs continuously submit UCTs in the HASP Inter-SC Trade Periods. CAISO continuously screens each submitted IFM to check contents and search for matching UCT submitted by the counterparty SC. CAISO provides feedback to the SCs regarding the validity of the UCTs based on the information that is available to CAISO at that time.</td>
</tr>
</tbody>
</table>

9.3.2 Information Requirements

A UCT contains the following information:

- Submission SC ID
- From SC ID
- To SC ID
- Trade time period
- Quantity (MW)

9.3.3 Validation of IST IFM Load Uplift Obligations

CAISO applies content and processing rules to IST IFM Load Uplift Obligations (UCT) as referenced in Attachment A of this BPM.
10. Reporting Information

Welcome to the Reporting Information section of CAISO BPM for Market Instruments. In this section you will find the following information:

- A description of the reports that are available to SCs

Technical interface documentation and report content details can be found in the Interface Specification for Market Results Services and Market Results Report Overview documentation at: [http://www.caiso.com/2359/2359b9866b2c0.html](http://www.caiso.com/2359/2359b9866b2c0.html)

10.1 Scope of CMRI Reports available to SCs

Exhibit 10-1.1 summarizes the reports that are available to SCs through the Customer Market Results Interface (CMRI). Details of the report contents are provided in subsequent sections.

### Exhibit 10-1.1: Summary of CMRI Reports

<table>
<thead>
<tr>
<th>Title</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-Ahead Generation Market Results</td>
<td>Day-Ahead Energy Schedules, Ancillary Services Awards, Load Following and RUC Capacity for Generating Units</td>
</tr>
<tr>
<td>Day-Ahead Demand Market Results</td>
<td>Day-Ahead Energy Schedules and Ancillary Services Awards of Participating Loads and Day-Ahead Energy Schedules for Non-Participating Loads</td>
</tr>
</tbody>
</table>
| Day-Ahead Residual Unit Commitment (RUC) Capacity | RUC Capacity and RUC Awards from the Residual Unit Commitment process. Posted hourly, the following values:  
- Capacity (total RUC capacity) - this is the positive difference between the RUC Schedule and the greater of the Day-Ahead Schedule and the Minimum Load level of a resource.  
- Award (RUC Award portion) – this is the portion of the RUC capacity from resources eligible to receive RUC Availability Payments.  
- For Interties the total RUC Schedule is displayed as the RUC Award product. |
| Day-Ahead Import/Export Schedules               | Day-Ahead Energy Schedules and Ancillary Services Awards at Intertie Scheduling Points.  
Addition of a new column called “Effective Intertie”, an element that only applies to intertie resources. In cases of an open-tie situation per market run results, this element will indicate the Secondary Tie identifier; whereas if there is no open-tie situation, this element will indicate the Primary Tie identifier. |
<p>| Day-Ahead Start-Up Instructions                 | Start-Up instructions resulting from the RUC process                                           |
| Day-Ahead Ancillary Service                     | Resource-specific Ancillary Service Awards resulting from the |</p>
<table>
<thead>
<tr>
<th>Title</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market Results</td>
<td>Integrated Forward Market run</td>
</tr>
<tr>
<td>Day-Ahead Market Power Mitigation (MPM) Results</td>
<td>Segments of the “new” or mitigated Bid as a result of the Day-Ahead Market Power Mitigation Process (MPM)</td>
</tr>
<tr>
<td>HASP Market Power Mitigation (MPM) Results</td>
<td>Segments of the “new” or mitigated Bid as a result of the HASP Market Power Mitigation Process (MPM)</td>
</tr>
<tr>
<td>FMM Market Power Mitigation (MPM) Results</td>
<td>Segments of the “new” or mitigated Bid as a result of the FMM Market Power Mitigation Process (MPM)</td>
</tr>
<tr>
<td>Default Energy Bid Curves</td>
<td>Independent Entity-supplied default Bid Curve data used in the Market Power Mitigation process</td>
</tr>
<tr>
<td>Day-Ahead Generation Commodity Prices</td>
<td>Day-Ahead resource-specific prices (for Energy Schedules, Ancillary Services Awards, RUC Awards) of Generating Units</td>
</tr>
<tr>
<td>Day-Ahead Demand Commodity Prices</td>
<td>Day-Ahead resource-specific prices for Energy Schedules and Ancillary Services Awards of Participating Loads; and resource-specific prices for Energy Schedules of Non-Participating Loads</td>
</tr>
<tr>
<td>Hour Ahead Scheduling Process (HASP) Schedules</td>
<td>Displays Hour-Ahead Scheduling Process results for the next Trading Hour. Posts the HASP Binding results relevant to hourly HASP Block Intertie Schedules. Posts HASP Advisory results relevant to all other Pre-Dispatch Resources.</td>
</tr>
<tr>
<td>Hour Ahead Scheduling Process (HASP) Schedule Prices</td>
<td>Displays Hour-Ahead Scheduling Process advisory resource-specific prices for the next Trading Hour.</td>
</tr>
<tr>
<td>Fifteen-Minute Market (FMM) Schedules</td>
<td>Displays FMM results for the next 15-minute interval. FMM schedules cover real-time Energy and Ancillary Services Awards. Addition of a new column called “Effective Intertie”, an element that only applies to intertie resources. In cases of an open-tie situation per market run results, this element will indicate the Secondary Tie identifier; whereas if there is no open-tie situation, this element will indicate the Primary Tie identifier. Addition of a new product commodity – code “IEEA”; with a display value of “CA Export Allocation”. This is the Imbalance Energy Export Allocation applicable for EIM resources. “Ramp Up” and “Ramp Down” in product types, and “Cleared” and “Market” schedule type attributes related to flexible ramping product. Both Cleared and Market will result to equal values as the flexible ramping product can’t be self-scheduled.</td>
</tr>
<tr>
<td>Fifteen-Minute Market (FMM) Schedule Prices</td>
<td>Displays FMM resource-specific prices for the next 15-minute interval. Covers prices for Energy and Ancillary Services Awards. Addition of a new Locational Marginal Price LMP component called “GHG” Greenhouse Gas only applicable for EIM resources. It is the additional LMP component due to the net energy export allocation constraint.</td>
</tr>
<tr>
<td>Day Ahead Finally Qualified Load Following Capacity</td>
<td>Day-Ahead Finally Qualified Load Following Up and Down Capacity for Metered Subsystems (MSS) resources</td>
</tr>
<tr>
<td>Title</td>
<td>Contents</td>
</tr>
<tr>
<td>---------------------------------------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Day-Ahead Unit Commitments</td>
<td>Resources that are self-committed or CAISO committed by the IFM or RUC process in the Day-Ahead Market</td>
</tr>
<tr>
<td>Default RMR Minimum Load &amp; Startup Cost Bid Curves</td>
<td>Displays the default minimum load and startup cost bid curves that will be used for the Market Power Mitigation (MPM) Process. This information originates from an independent entity and applies to RMR units only.</td>
</tr>
<tr>
<td>Day-Ahead Import-Export Commodity Prices</td>
<td>Day-Ahead resource-specific prices (for Energy Schedules, Ancillary Services Awards, RUC Awards) of System Resources</td>
</tr>
<tr>
<td>Extremely Long Start Resource Startup Instructions</td>
<td>Startup instructions resulting from the Extremely Long Start Commitment (ELC) process.</td>
</tr>
<tr>
<td>Day-Ahead Reliability Must Run (RMR) Dispatches</td>
<td>RMR units that either have an Energy Schedule (from the IFM run) that is flagged as an RMR Dispatch and/or a Manual RMR Dispatch</td>
</tr>
<tr>
<td>Expected Energy Allocation Details</td>
<td>Displays the post-market Expected Energy results from the energy accounting process. Expected Energy is the sum total of all DA and RT (including FMM and RTD) market awards, Exceptional Dispatches and any other Dispatch Instructions, taking into account physical limitations (outage management system), disaggregated into their Settlement components. For residual energy, report includes the price at which the residual energy will be settled. User may choose to display allocation either by Default Energy Bid, or the final input bid used by the market systems (SIBR clean bid as adjusted by market pre-processors). Addition of two new expected energy type codes applicable for EIM resources:  • BASE - real-time expected energy based on the base schedules  • MDE - manual dispatch energy signals</td>
</tr>
<tr>
<td>Conformed Dispatch Notice (CDN)</td>
<td>Summary of the Day-Ahead and Real-Time Energy Schedules, Ancillary Service Awards, RMR Dispatches, Competitive Constraint Run results of RMR resources</td>
</tr>
<tr>
<td>Expected Energy</td>
<td>Post-market or after-the-fact energy accounting results for Settlement calculations. This report will contain the Total Expected Energy for Day Ahead, Fifteen-Minute, and Real Time Dispatch, and include Instructed and Total energy.</td>
</tr>
<tr>
<td>ISO Commitment Cost Details</td>
<td>Includes Commitment and transition Flags, time periods and Costs to validate the Bid Cost Recovery charge in Settlements</td>
</tr>
<tr>
<td>Non-Dispatchable Time Ranges</td>
<td>Specifies the start and end time of non-dispatchable periods including resource commitments, transitions, operations within a forbidden region and DOP corrections. Used to validate the Bid Cost Recovery charge in Settlements.</td>
</tr>
<tr>
<td>CRN</td>
<td>Reports the MW breakdown and CRN number market results for ETC/TOR Self-Schedules in the DAM and the RTM. These MWs breakdown are inputs used in the ETC/TOR balancing rights, and are not the final ETC/TOR balancing rights. RTM CRN reporting includes</td>
</tr>
<tr>
<td>Title</td>
<td>Contents</td>
</tr>
<tr>
<td>-------</td>
<td>----------</td>
</tr>
<tr>
<td><strong>ETC/TOR schedule changes after the close of the RTM.</strong>&lt;br&gt;Note: This report has limited functionality, and is only available in the GUI. The same results are posted to the CAISO SFTP site for downloading. Access to the CRN data through the SFTP site is managed through the AARF (Application Account Request Form) process.</td>
<td></td>
</tr>
<tr>
<td><strong>Fifteen-Minute Market (FMM) Flexible Ramping Constraint Capacity</strong></td>
<td>Reports the amount of upward ramping MW quantity of Flexible Ramping Constraint capacity awarded for each resource.</td>
</tr>
<tr>
<td><strong>Resource-Specific VER Forecast Usage</strong></td>
<td>Posts the actual 5-minute and 15-minute load forecast used by RTM. Depending on option chosen by the SC and forecast availability, forecast may come from either the values submitted by the SC or from the forecast generated by CAISO systems. Posts for all intervals (binding and advisory) in the FMM and RTD run time horizon.</td>
</tr>
<tr>
<td><strong>Real-Time Dispatch (RTD) Schedules</strong></td>
<td>Reports the 5-minute interval based resource level binding energy schedules from the real-time 5-minute market runs. “Ramp Up” and “Ramp Down” in product types, and “Cleared” and “Market” schedule type attributes related to flexible ramping product. Both Cleared and Market will result to equal values as the flexible ramping product can’t be self-scheduled.</td>
</tr>
<tr>
<td><strong>Real-Time Dispatch (RTD) Advisory Schedules</strong></td>
<td>Reports the 5-minute interval based resource level advisory energy schedules from the real-time 5-minute market horizon. “Ramp Up” and “Ramp Down” in product types, and “Cleared” and “Market” schedule type attributes related to flexible ramping product. Both Cleared and Market will result to equal values as the flexible ramping product can’t be self-scheduled.</td>
</tr>
<tr>
<td><strong>Real-Time Dispatch (RTD) Schedule Prices</strong></td>
<td>Reports the 5-minute interval based resource level binding prices from the real-time 5-minute market runs.</td>
</tr>
</tbody>
</table>
| **Intertie Resource Transaction ID** | Reports all of the unique alphanumeric identifiers, that were dynamically generated by the bidding system (SiBR) referred to as the “Transaction ID”; and its corresponding attributes:  
  - RegisteredInterTie identifier  
  - SchedulingCoordinator identifier  
  - PrimaryFlow identifier  
  - SecondaryFlow identifier  
  - AggregatedPhNode identifier  
  - IndividualPhNode identifier  
  - Direction (Import, Export)  
  - Energy Product Type (Firm Energy, Non Firm Energy, Dynamic Interchange, Wheeling, Unit Contingency)  
  - Purchase Service Entity (PSE)  
  - Wheeling Resource identifier  
  - Wheeling Resource registeredFlag |
<p>| <strong>Day-Ahead Base Schedules</strong> | Reports the generation and interchange base schedules submitted for the day-ahead and/or real-time markets to the CAISO. These represent the forward energy schedules, with hourly granularity, that is the baseline to measure deviations for settlement through the EIM. |</p>
<table>
<thead>
<tr>
<th>Title</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Real-Time Base Schedules</td>
<td>Reports the generation and interchange base schedules submitted for the day-ahead and/or real-time markets to the CAISO. These represent the forward energy schedules, with hourly granularity, that is the baseline to measure deviations for settlement through the EIM.</td>
</tr>
<tr>
<td>Base Schedules</td>
<td>Reports the generation and interchange EIM Base Schedules submitted for the day-ahead and/or real-time markets to the CAISO. These represent the forward energy schedules, with hourly granularity, that is the baseline to measure deviations for settlement through the EIM.</td>
</tr>
<tr>
<td>EIM Transfer</td>
<td>Reports the Energy Imbalance Market transfer (mw) breakdown for each EIM Entity Balancing Authority Area and EIM Entity Balancing Authority Area group under the real-time market runs (RTPD and RTD).</td>
</tr>
<tr>
<td>Load Base Schedules</td>
<td>Reports the base schedules for load resources under the real-time markets</td>
</tr>
<tr>
<td>Balancing Test Results</td>
<td>Report that provide the results for the series of tests conducted to ensure that each EIM Entity Balancing Authority Area has sufficient resources to serve its load while still realizing the benefits of increased resource diversity. Please refer to the Energy Imbalance Market Business Practice Manual document for more information.</td>
</tr>
<tr>
<td>Transmission Violation Test Results</td>
<td>Report that provide the results for the series of tests conducted to ensure that each EIM Entity Balancing Authority Area has sufficient resources to serve its load while still realizing the benefits of increased resource diversity. Please refer to the Energy Imbalance Market Business Practice Manual document for more information.</td>
</tr>
<tr>
<td>Flexible Ramp Requirement Sufficiency Test Results</td>
<td>Report that provide the results for the series of tests conducted to ensure that each EIM Entity Balancing Authority Area has sufficient resources to serve its load while still realizing the benefits of increased resource diversity. Please refer to the Energy Imbalance Market Business Practice Manual document for more information.</td>
</tr>
<tr>
<td>Bid Range Capacity Test Results</td>
<td>Report that provide the results for the series of tests conducted to ensure that each EIM Entity Balancing Authority Area has sufficient resources to serve its load while still realizing the benefits of increased resource diversity. Please refer to the Energy Imbalance Market Business Practice Manual document for more information.</td>
</tr>
<tr>
<td>Fifteen Minute Market (FMM) Movement Points</td>
<td>Provide resource-level Movement Start and End Points (mw), based on the binding and first advisory intervals, resulting from the FMM/15-minute market run.</td>
</tr>
<tr>
<td>Real Time Dispatch (RTD) Movement Points</td>
<td>Provide resource-level Movement Start and End Points (mw), based on the binding and first advisory intervals, resulting from the RTD/5-minute market run.</td>
</tr>
<tr>
<td>Fifteen Minute Market (FMM) Flexible Ramp Price Breakdown</td>
<td>Provide the flexible ramping total price (FRMP) and its BAA level price breakdown, resulting from the FMM/15-minute market outputs.</td>
</tr>
<tr>
<td>Title</td>
<td>Contents</td>
</tr>
<tr>
<td>--------------------------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Real Time Dispatch (RTD) Flexible Ramp Price Breakdown</td>
<td>Provide the flexible ramping total price (FRMP) and its BAA level price breakdown, resulting from the RTD/5-minute market outputs.</td>
</tr>
<tr>
<td>Resource Level Movement</td>
<td>Provide 15-minute and 5-minute resource-level Forecasted Movement (FM) and Uncertainty Movement (UM) for generator and intertie resources, published at TD+1.</td>
</tr>
<tr>
<td>Greenhouse Gas Bid Cap</td>
<td>Provides the daily greenhouse gas maximum cost value ($/mwh) of EIM participating resources. This report is available to the scheduling coordinator of the resource.</td>
</tr>
<tr>
<td>EIM After-the-fact Interchange Schedules</td>
<td>Provide the after-the-fact values of the interchange base schedules submitted by the EIM entities. The values are reported in 5 or 15 minute intervals and can be submitted up to T-8 calendar days. After-The-Fact interchange schedules describes the MWh value displayed on the e-Tag after the timeframe is in the past. This report is available to the EIM entity.</td>
</tr>
<tr>
<td>Variable Energy Resource Forecast</td>
<td>Provide the day-ahead, rolling, and locked or final hour-ahead forecast for variable energy resources. This report will be available to the scheduling coordinator of the resource.</td>
</tr>
<tr>
<td>Electricity Price Index</td>
<td>Provide the CAISO market resource electricity price index values that are used as inputs in the day-ahead and real-time market to calculate the auxiliary power portion of start-up costs.</td>
</tr>
</tbody>
</table>

**Convergence Bidding Reports**

The following four Convergence Bidding reports are available through the Customer Market Results Interface (CMRI).

Reports 4.2, 4.3 and 4.4 are associated with the CRR Adjustment Settlement Rule.

For additional details on the CRR Adjustment Settlement Rule, please see the BPM for Market Operations, Appendix F.

| Day Ahead Convergence Bidding Awards        | Displays the market Virtual Bidding supply and demand awards that were cleared in the day-ahead market for energy Addition of a new column called “Interie”, which defines the “Primary Tie” if the virtual bid Pnode or Apnode is external to CAISO |
| Hourly Prices due to Convergence Bidding for CRR Adjustment | Displays the hourly prices that CAISO uses to calculate Congestion Revenue Rights (CRR) adjustments due to Virtual Bidding.                                                                 |
| Binding Transmission Constraints due to Convergence Bidding for CRR Adjustment Report | Displays supporting data for settlement charges imposed on scheduling coordinators, as a result of the application of the CRR settlement rule - specifically CRR flow impact on award locations for each scheduling coordinator. |
| Flow Impact due to Convergence Bidding for CRR Adjustment | Displays supporting data for settlement charges imposed on scheduling coordinators, as a result of the application of the CRR settlement rule – specifically CRR flow impact aggregated by Entity, where the Entity is a Convergence Bidding Entity name that coincides with a CRR Holder. |
10.2 Scope of Transmission Constraint Reports

Exhibit 10-2 summarizes the Transmission Constraints Enforcement List reports that are available through the Customer Market Results Interface (CMRI) and CAISO Portal for users who obtain access as detailed in Tariff Section 6.5.10. This tariff section details the process for completing the Non-Disclosure Agreement for Transmission Constraints Enforcement Lists.

Details of the report contents are provided in subsequent sections.

The reports outlined in section 10.2 are provided for information only and are not considered to be of settlement quality. Stated differently, the information provided in these reports may vary from the information Scheduling Coordinators receive in their settlement statements, which are more specific to their individual resources performance.

**Exhibit 10-2.1: Summary of Transmission Constraints Enforcement List Reports**

**CMRI:**

<table>
<thead>
<tr>
<th>Title</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Flowgate Constraints</td>
<td>Displays the complete list of flowgate constraints e.g. Line, Transformer, Phase Shifter, Series Device or Transmission Corridor</td>
</tr>
<tr>
<td>Transmission Corridor Constraints</td>
<td>Displays the complete list of transmission corridor constraints defined in the market</td>
</tr>
<tr>
<td>Nomogram Constraint Enforcements</td>
<td>Displays the list of nomogram constraints that are active for the particular trading day and market, which can be either enforced or not enforced</td>
</tr>
<tr>
<td>Nomogram Constraint Definitions</td>
<td>Displays the complete list of defined nomogram constraints in the market</td>
</tr>
<tr>
<td>Transmission Contingencies</td>
<td>Displays the complete list of transmission contingencies defined in the market</td>
</tr>
</tbody>
</table>

**Portal:**

<table>
<thead>
<tr>
<th>Title</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-Ahead Load Distribution Factors</td>
<td>Displays the load distribution factors used in the Day-Ahead Market.</td>
</tr>
<tr>
<td>Shift Factors</td>
<td>Displays the complete list of shift factors for all binding constraints in the IFM, HASP, and RTED markets.</td>
</tr>
<tr>
<td>Transmission Limits</td>
<td>Displays the transmission limits for all critical constraints in the IFM, HASP, and RTED markets. Critical constraints are classified as those constraints for which in each respective market run are at or approaching their limit.</td>
</tr>
</tbody>
</table>
10.2.1 Flowgate Constraints

Exhibit 10-2.2: Flowgate Constraints

**Report Description**
Displays the complete list of flowgate constraints e.g. Line, Transformer, Phase Shifter, Series Device or Transmission Corridor

**Business Trigger**
Publication of the Post Day-Ahead Market (D+1) by one hour after the publication of the Day-Ahead results and Pre Day-Ahead Market (D+2) by 18:00.

**Layout**
For illustrative purposes, the following is a sample listing report layout:

<table>
<thead>
<tr>
<th>Flowgate Name</th>
<th>Type</th>
<th>Enforced Flag</th>
<th>Competitive Flag</th>
</tr>
</thead>
<tbody>
<tr>
<td>14122_AAAAA_600_B8002_BBB-CCC_500_BR_1_5</td>
<td>LINE</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>55533_XXXXX_1_14_1_12345_CASEFEG_456_XF_1</td>
<td>XFMX</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>54557_TTTT_ES_115_55215_EDCR-555_115_ES_1</td>
<td>PFXH</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>40006_EEEE_XX_500_66015_BB9BBB_YY_500_BR_1_1</td>
<td>SERD</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>MARKETSCH_MSL</td>
<td>TCOR</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>BRANCHGBPRA_BG</td>
<td>TCOR</td>
<td>No</td>
<td>Yes</td>
</tr>
</tbody>
</table>

Listed below are the data elements contained in this report.

**Attributes**
- \( P \) = denotes a user input report parameter
- \( G \) = denotes a report group section attribute; displayed within the report title

<table>
<thead>
<tr>
<th>#</th>
<th>Attribute</th>
<th>High-Level Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Flowgate Name</td>
<td>The unique alphanumeric identifier name of a flowgate</td>
</tr>
<tr>
<td>2</td>
<td>Trade Date ( P )</td>
<td>Date on when the trade transaction occurs within the market</td>
</tr>
</tbody>
</table>
| 3 | Market \( P \) | Type of market in which the nomogram constraints applies to:
  - Post Day-Ahead
  - Pre Day-Ahead |
The equipment classification of the flow gate, as follows:

- **LINE** (Individual transmission line between two stations)
- **XFMR** (Transformer in station transforming from one voltage to another)
- **PHSH** (Phase shifter controlling flow)
- **SERD** (Series device capacitor, reactor)
- **TCOR** (Transmission Corridor)

<table>
<thead>
<tr>
<th>Type</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enforced Flag</td>
<td>The indicator specifying if the flow gate is enforced or not (Yes/No)</td>
</tr>
<tr>
<td>Competitive Flag</td>
<td>The indicator specifying if the flow gate is competitive (Yes/No)</td>
</tr>
</tbody>
</table>
10.2.2 Transmission Corridor Constraints

Exhibit 10-2.3: Transmission Corridor Constraints

**Report Description**
Displays the complete list of transmission corridor constraints defined in the market.

**Business Trigger**
Publication of the Post Day-Ahead Market (D+1) by one hour after the publication of the Day-Ahead results and Pre Day-Ahead Market (D+2) by 18:00.

**Layout**
For illustrative purposes, the following is a sample listing report layout:

```
<table>
<thead>
<tr>
<th>Transmission Corridor Name</th>
<th>Equipment Name</th>
<th>Equipment Type</th>
<th>FROM Station</th>
<th>TO Station</th>
</tr>
</thead>
<tbody>
<tr>
<td>BRANCHGRA MSL</td>
<td>11111 XXXXX 230 3457 AAAA 230 BR 1 1</td>
<td>LINE</td>
<td>STATION1</td>
<td>STATION2</td>
</tr>
<tr>
<td>BRANCHGRA MSL</td>
<td>11111 YYYY 5457 BBBB 500 BR 1 1</td>
<td>LINE</td>
<td>STATION3</td>
<td>STATION4</td>
</tr>
<tr>
<td>BRANCHGRA MSL</td>
<td>22222 ZZZZZ 230 3457 ABAB 230 BR 1 1</td>
<td>LINE</td>
<td>STATION5</td>
<td>STATION5</td>
</tr>
<tr>
<td>BRANCHGRA MSL</td>
<td>99999 AAAAA 500 5704 BBBB 500 BR 1 1</td>
<td>LINE</td>
<td>STATION7</td>
<td>STATION6</td>
</tr>
<tr>
<td>BRANCHGRA MSL</td>
<td>11111 XXXXX 230 7777 XXXXX 230 BR 1 1</td>
<td>LINE</td>
<td>STATION9</td>
<td>STATION7</td>
</tr>
<tr>
<td>BRANCHGRA MSL</td>
<td>55555 XXXXX 230 3457 AAAAA 230 BR 1 1</td>
<td>LINE</td>
<td>STATION1</td>
<td>STATION1</td>
</tr>
</tbody>
</table>
```

**Attributes**
Listed below are the data elements contained in this report.

- **P** = denotes a user input report parameter
- **G** = denotes a report group section attribute; displayed within the report title

<table>
<thead>
<tr>
<th>#</th>
<th>Attribute</th>
<th>High-Level Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trade Date PG</td>
<td>Date on when the trade transaction occurs within the market</td>
<td></td>
</tr>
<tr>
<td>Market PG</td>
<td>Type of market in which the transmission corridor constraints applies to:</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Post Day-Ahead</td>
<td></td>
</tr>
<tr>
<td></td>
<td>- Pre Day-Ahead</td>
<td></td>
</tr>
<tr>
<td>Transmission Corridor Name</td>
<td>The unique alphanumeric identifier name of a transmission corridor</td>
<td></td>
</tr>
<tr>
<td>Equipment Name</td>
<td>The unique alphanumeric identifier for an equipment comprising a transmission corridor</td>
<td></td>
</tr>
</tbody>
</table>
The classification of the equipment, as follows:

- **LINE** (individual transmission line between two stations)
- **XFMR** (Transformer in station transforming from one voltage to another)
- **PHSH** (Phase shifter controlling flow)
- **SERD** (Series device capacitor, reactor)

**FROM Station**
This refers to the name of station at the “FROM” end of the line

**TO Station**
This refers to the name of station at the “TO” end of the line

### 10.2.3 Nomogram Constraint Enforcements

**Exhibit 10-2.4: Nomogram Constraint Enforcements**

**Report Description**
Displays the list of nomogram constraints that are active for the particular trading day and market, which can be either enforced or not enforced

**Business Trigger**
Publication of the Post Day-Ahead Market (D+1) by one hour after the publication of the Day-Ahead results and Pre Day-Ahead Market (D+2) by 18:00.

**Layout**
For illustrative purposes, the following is a sample listing report layout:

<table>
<thead>
<tr>
<th>Nomogram Name</th>
<th>Enforced Flag</th>
<th>Competitive Flag</th>
<th>Constraint Type</th>
<th>Curve ID</th>
<th>Segment ID</th>
<th>Effective Start Datetime</th>
<th>Effective End Datetime</th>
</tr>
</thead>
<tbody>
<tr>
<td>7-RKX_SALTO_B2_SUN</td>
<td>Yes</td>
<td>Yes</td>
<td>LE</td>
<td>1</td>
<td>1</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
</tr>
<tr>
<td>B888_5XYYY_MCR</td>
<td>No</td>
<td>Yes</td>
<td>GE</td>
<td>1</td>
<td>1</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
</tr>
<tr>
<td>2222222-ABD-CLP2-LOS99</td>
<td>Yes</td>
<td>No</td>
<td>GE</td>
<td>1</td>
<td>1</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
</tr>
<tr>
<td>X-111 AAAA_AAA_SUN</td>
<td>No</td>
<td>No</td>
<td>SE</td>
<td>1</td>
<td>1</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
</tr>
<tr>
<td>PAUL_111_SUN</td>
<td>Yes</td>
<td>No</td>
<td>LE</td>
<td>1</td>
<td>1</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
</tr>
<tr>
<td>222222 T-KA Q4752_N2</td>
<td>Yes</td>
<td>No</td>
<td>GE</td>
<td>1</td>
<td>1</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
</tr>
<tr>
<td>SC_CO99000_RYXJXY_A8</td>
<td>Yes</td>
<td>No</td>
<td>LE</td>
<td>1</td>
<td>1</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
<td>mm/dd/yyyy hh:mm:ss AM/PM</td>
</tr>
</tbody>
</table>

Listed below are the data elements contained in this report.

**Attributes**

- **P** = denotes a user input report parameter
- **G** = denotes a report group section attribute; displayed within the report title
<table>
<thead>
<tr>
<th>Trade Date</th>
<th>Date on when the trade transaction occurs within the market</th>
</tr>
</thead>
<tbody>
<tr>
<td>Market</td>
<td>Type of market in which the nomogram constraint enforcements applies to:</td>
</tr>
<tr>
<td></td>
<td>- Post Day-Ahead</td>
</tr>
<tr>
<td></td>
<td>- Pre Day-Ahead</td>
</tr>
<tr>
<td>Nomogram Name</td>
<td>The unique alphanumeric identifier name of a nomogram</td>
</tr>
<tr>
<td>Enforced Flag</td>
<td>The indicator specifying if the nomogram is enforced or not (Yes/No)</td>
</tr>
<tr>
<td>Competitive Flag</td>
<td>The indicator specifying if the nomogram is competitive (Yes/No)</td>
</tr>
<tr>
<td>Constraint Type</td>
<td>The classification of the constraint, as follows:</td>
</tr>
<tr>
<td></td>
<td>- LE (Less or equal)</td>
</tr>
<tr>
<td></td>
<td>- GE (Greater or equal)</td>
</tr>
<tr>
<td>Curve ID</td>
<td>The numeric identifier of the Curve. There can be up to N number of Curves defined per transmission corridor</td>
</tr>
<tr>
<td>Segment ID</td>
<td>The numeric identifier of the Segment of the Curve. There can be up to N number of segments per Curve</td>
</tr>
<tr>
<td>Effective Start Datetime</td>
<td>The effective start datetime of the nomogram enforcement (Pacific)</td>
</tr>
<tr>
<td>Effective End Datetime</td>
<td>The effective end datetime of the nomogram enforcement (Pacific)</td>
</tr>
</tbody>
</table>

### 10.2.4 Nomogram Constraint Definitions

Exhibit 10-2.5: Nomogram Constraint Definitions

<table>
<thead>
<tr>
<th>Report Description</th>
<th>Displays the complete list of defined nomogram constraints in the market</th>
</tr>
</thead>
<tbody>
<tr>
<td>Business Trigger</td>
<td>Publication of the Post Day-Ahead Market (D+1) by one hour after the publication of the Day-Ahead results and Pre Day-Ahead Market (D+2) by 18:00.</td>
</tr>
<tr>
<td>Layout</td>
<td>For illustrative purposes, the following is a sample listing report layout:</td>
</tr>
</tbody>
</table>
Listed below are the data elements contained in this report.

**Attributes**

- **P** = denotes a user input report parameter
- **G** = denotes a report group section attribute; displayed within the report title

<table>
<thead>
<tr>
<th>#</th>
<th>Attribute</th>
<th>High-Level Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Nomogram Name</td>
<td>The unique alphanumeric identifier name of a nomogram</td>
</tr>
<tr>
<td>2</td>
<td>Variable Name</td>
<td>The unique alphanumeric identifier of the nomogram variable</td>
</tr>
<tr>
<td>3</td>
<td>Variable Type</td>
<td>The variable type, representing flow across a transmission corridor (TCR), aggregated generator (AGR), or generator (G)</td>
</tr>
<tr>
<td>4</td>
<td>Curve ID</td>
<td>The numeric identifier of the Curve. There can be up to N number of Curves defined per nomogram</td>
</tr>
<tr>
<td>5</td>
<td>Segment ID</td>
<td>The numeric identifier of the Segment of the Curve. There can be up to N number of segments per Curve.</td>
</tr>
<tr>
<td>6</td>
<td>Coefficient</td>
<td>The participation factor of the variable in the nomogram inequality</td>
</tr>
</tbody>
</table>

---

<table>
<thead>
<tr>
<th>Nomogram Name</th>
<th>Variable Name</th>
<th>Variable Type</th>
<th>Curve ID</th>
<th>Segment ID</th>
<th>Coefficient</th>
</tr>
</thead>
<tbody>
<tr>
<td>T-XXX_SALXX NG_SUM</td>
<td>XXXX NG 1</td>
<td>TCR</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>T-XXX_SALXX NG_SUM</td>
<td>XXXX NG 2</td>
<td>TCR</td>
<td>1</td>
<td>1</td>
<td>0.07</td>
</tr>
<tr>
<td>T-XXX_SALXX NG_SUM</td>
<td>XXXX NG 3</td>
<td>TCR</td>
<td>1</td>
<td>1</td>
<td>0.25</td>
</tr>
<tr>
<td>T-XXX_SALXX NG_SUM</td>
<td>XXXX NG 4</td>
<td>TCR</td>
<td>1</td>
<td>1</td>
<td>0.32</td>
</tr>
<tr>
<td>BBBB YYYY YYYY NG</td>
<td>YYYY NG 7</td>
<td>AGR</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>BBBB YYYY YYYY NG</td>
<td>YYYY NG 6</td>
<td>AGR</td>
<td>1</td>
<td>1</td>
<td>0.20</td>
</tr>
<tr>
<td>BBBB YYYY YYYY NG</td>
<td>YYYY NG 9</td>
<td>AGR</td>
<td>1</td>
<td>1</td>
<td>0.66</td>
</tr>
</tbody>
</table>
10.2.5 Transmission Contingencies

Exhibit 10-2.6: Transmission Contingencies

<table>
<thead>
<tr>
<th>Report Description</th>
<th>Displays the complete list of transmission contingencies defined in the market</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Business Trigger</th>
<th>Publication of the Post Day-Ahead Market (D+1) by one hour after the publication of the Day-Ahead results and Pre Day-Ahead Market (D+2) by 18:00.</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Layout</th>
<th>For illustrative purposes, the following is a sample listing report layout:</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>#</th>
<th>Attribute</th>
<th>High-Level Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Contingency Title</td>
<td>The unique alphanumeric identifier of the contingency name</td>
</tr>
<tr>
<td>2</td>
<td>Enforced Flag</td>
<td>The indicator specifying if the contingency is enforced or not (Yes/No)</td>
</tr>
<tr>
<td>3</td>
<td>TAC Area</td>
<td>This represents the zone at which the contingency is defined in</td>
</tr>
<tr>
<td>4</td>
<td>Equipment Station</td>
<td>The substation where the outaged equipment is located at</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Attribute</th>
<th>High-Level Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trade Date</td>
<td>Date on when the trade transaction occurs within the market</td>
</tr>
<tr>
<td>Market</td>
<td>Type of market in which the transmission contingencies applies to:</td>
</tr>
<tr>
<td></td>
<td>- Post Day-Ahead</td>
</tr>
<tr>
<td></td>
<td>- Pre Day-Ahead</td>
</tr>
</tbody>
</table>

Listed below are the data elements contained in this report.

P = denotes a user input report parameter

G = denotes a report group section attribute; displayed within the report title
10.2.6  Day-Ahead Load Distribution Factors

Exhibit 10-2.7: Day-Ahead Load Distribution Factors

- **Report Description**
  Displays the load distribution factors (LDFs) by node used in the Day-Ahead Market. To protect confidential data the load distribution factors for single customer nodes are aggregated and reported by DLAP. Load PNode changes will only happen when there is a Full Network Model update. Refer to FNM BPM section 4.2.1 for details to inform the ISO which LDFs can be released for the multiple customer nodes, UDCs must complete and submit both the affidavit and PNodes for LDF Release template listed below:

- **Single Customer Pricing Node Certification Affidavit Template**
- **Pricing Nodes to Release for Load Distribution Factor Report**

- **Business Trigger**
  Trade Date + 3 days by 6:00 AM PPT.
  Example:
  - For Trade Date 9/12/2011,
  - Report is accessible on 9/15/2011.

- **Layout**
  For illustrative purposes, the following is a sample listing report layout:

<table>
<thead>
<tr>
<th>GMT Interval</th>
<th>DLAP</th>
<th>Node Name</th>
<th>LDF</th>
</tr>
</thead>
<tbody>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>DLAP_PGAE-ANDE</td>
<td>NODE_A</td>
<td>0.000240507</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>DLAP_PGAE-ANDE</td>
<td>NODE_B</td>
<td>0.000330832</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>DLAP_PGAE-ANDE</td>
<td>NODE_C</td>
<td>6.01E-05</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>DLAP_PGAE-ANDE</td>
<td>NODE_D</td>
<td>0.001485439</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>DLAP_PGAE-ANDE</td>
<td>NODE_E</td>
<td>0</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>DLAP_PGAE-ANDE</td>
<td>NODE_F</td>
<td>0.005004935</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>DLAP_PGAE-ANDE</td>
<td>NODE_G</td>
<td>0.00060646</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>DLAP_PGAE-ANDE</td>
<td>NODE_H</td>
<td>0</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>DLAP_PGAE-ANDE</td>
<td>NODE_I</td>
<td>0.000913237</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>DLAP_PGAE-ANDE</td>
<td>AGGR_UNDISCLOSED</td>
<td>0.000127877</td>
</tr>
</tbody>
</table>
Attributes

Listed below are the data elements contained in this report.

Note: the reports are contained in files accessed from the CAISO Portal.

<table>
<thead>
<tr>
<th>Attribute</th>
<th>High-Level Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>GMT Interval</td>
<td>Start time of the time interval (GMT)</td>
</tr>
<tr>
<td>DLAP</td>
<td>Default Load Aggregation Point. Used to select nodes within a particular DLAP.</td>
</tr>
<tr>
<td>Node</td>
<td>The unique alphanumeric identifier of the node name. Note, single customer nodes are not disclosed. These nodes are reported as an aggregate value by DLAP and listed as “AGGR_UNDISCLOSED”</td>
</tr>
<tr>
<td>LDF</td>
<td>The load distribution factor used in the Day-Ahead Market for the node and interval.</td>
</tr>
</tbody>
</table>

10.2.7 Shift Factors (Power Transfer Distribution Factors)

Exhibit 10-2.8: Shift Factors

Report Description

Displays the complete list of shift factors (aka Power Transfer Distribution Factors) for all binding constraints in the IFM, HASP, and RTED markets. Shift factors for binding constraints in other markets such as RTCD are not included.

Trade Date + 3 days by 6:00 AM PPT.

Business Trigger

Example:
- For Trade Date 9/12/2011,
- Report is accessible on 9/15/2011.

Layout

Note, the report is accessible via download only. For illustrative purposes, the following is a sample listing report layout:

<table>
<thead>
<tr>
<th>Attribute</th>
<th>GMT Interval</th>
<th>Constraint Name</th>
<th>Constraint Cause</th>
<th>Curve ID</th>
<th>Segment ID</th>
<th>Node Name</th>
<th>Shift Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>FLOWGATE</td>
<td>4/13/2012 11:00:00 AM</td>
<td>31512_BIG BEN2_115_31516_WYANDJT2_115_BR_1_2</td>
<td>Base Case</td>
<td>1</td>
<td></td>
<td>N1E_1_N001</td>
<td>0.038230803</td>
</tr>
<tr>
<td>FLOWGATE</td>
<td>4/13/2012 11:00:00 AM</td>
<td>31512_BIG BEN2_115_31516_WYANDJT2_115_BR_1_2</td>
<td>Base Case</td>
<td>1</td>
<td></td>
<td>N1E_1_N002</td>
<td>0.092708223</td>
</tr>
<tr>
<td>FLOWGATE</td>
<td>4/13/2012 11:00:00 AM</td>
<td>31512_BIG BEN2_115_31516_WYANDJT2_115_BR_1_2</td>
<td>Base Case</td>
<td>1</td>
<td></td>
<td>N1E_1_N003</td>
<td>0.027463121</td>
</tr>
<tr>
<td>FLOWGATE</td>
<td>4/13/2012 11:00:00 AM</td>
<td>31512_BIG BEN2_115_31516_WYANDJT2_115_BR_1_2</td>
<td>Base Case</td>
<td>1</td>
<td></td>
<td>N1E_1_N004</td>
<td>0.027463121</td>
</tr>
<tr>
<td>FLOWGATE</td>
<td>4/13/2012 11:00:00 AM</td>
<td>31512_BIG BEN2_115_31516_WYANDJT2_115_BR_1_2</td>
<td>Base Case</td>
<td>1</td>
<td></td>
<td>N1E_1_GN05</td>
<td>0.027463121</td>
</tr>
<tr>
<td>NOMOGRAM</td>
<td>4/13/2012 11:00:00 AM</td>
<td>RAVENSWDSANMAT_NG_1</td>
<td>Base Case</td>
<td>1</td>
<td></td>
<td>N1E_1_GN10</td>
<td>0.038230803</td>
</tr>
<tr>
<td>NOMOGRAM</td>
<td>4/13/2012 11:00:00 AM</td>
<td>RAVENSWDSANMAT_NG_1</td>
<td>Base Case</td>
<td>1</td>
<td></td>
<td>N1E_1_GN11</td>
<td>0.092708223</td>
</tr>
<tr>
<td>NOMOGRAM</td>
<td>4/13/2012 11:00:00 AM</td>
<td>RAVENSWDSANMAT_NG_1</td>
<td>Base Case</td>
<td>1</td>
<td></td>
<td>N1E_1_GN12</td>
<td>0.027463121</td>
</tr>
<tr>
<td>NOMOGRAM</td>
<td>4/13/2012 11:00:00 AM</td>
<td>RAVENSWDSANMAT_NG_1</td>
<td>Base Case</td>
<td>1</td>
<td></td>
<td>N1E_1_GN13</td>
<td>0.027463121</td>
</tr>
<tr>
<td>NOMOGRAM</td>
<td>4/13/2012 11:00:00 AM</td>
<td>RAVENSWDSANMAT_NG_1</td>
<td>Base Case</td>
<td>1</td>
<td></td>
<td>N1E_1_GN14</td>
<td>0.027463121</td>
</tr>
</tbody>
</table>
Attributes

Listed below are the data elements contained in this report.

Note: the reports are contained in files accessed from the CAISO Portal.

<table>
<thead>
<tr>
<th>Attribute</th>
<th>High-Level Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Constraint Class</td>
<td>Indicates whether the constraint is a Flow gate (branch or branch group), Nomogram, or Intertie.</td>
</tr>
<tr>
<td>GMT Interval</td>
<td>Start time of the time interval (GMT)</td>
</tr>
<tr>
<td>Constraint Name</td>
<td>Name of transmission element, including interchanges, branches, branch groups, and nomograms.</td>
</tr>
<tr>
<td>Constraint Direction</td>
<td>The direction in which the constraint is binding: &quot;From-To&quot; or &quot;To-From&quot; for Flow gates; &quot;Import&quot; or &quot;Export&quot; for Interties; &quot;LE&quot; (Less or Equal) or &quot;GE&quot; (Greater or Equal) for Nomograms.</td>
</tr>
<tr>
<td>Constraint Type</td>
<td>For ITC constraints only, the type of the ITC constraint: &quot;Energy/AS&quot; for Energy/AS scheduling limit; &quot;AS&quot; for AS scheduling limit.</td>
</tr>
<tr>
<td>Constraint Cause</td>
<td>For all transmission elements except Interties and Nomograms, indicates whether the limit is associated with a contingency or not. If a contingency is associated, the contingency name is displayed; otherwise “Base Case” is displayed.</td>
</tr>
<tr>
<td>Curve ID</td>
<td>For Nomograms, indicates which curve ID the limit applies to.</td>
</tr>
<tr>
<td>Segment ID</td>
<td>For Nomograms, indicates which segment ID the limit applies to.</td>
</tr>
<tr>
<td>Node Name</td>
<td>The unique alphanumeric identifier of the Node name</td>
</tr>
<tr>
<td>Shift Factor</td>
<td>The power flow contribution from an injection at the Node on the constraint in the specified direction during the specified time interval.</td>
</tr>
</tbody>
</table>

Note: In order to duplicate calculation of MCC shadow cost for flowgates, TCORs, and MSLs should be multiplied by (-1). Otherwise use SF signs as indicated in the report. Shadow cost for nomograms and interties should be used as they are on Oasis.

10.2.8 Transmission Limits

Exhibit 10-2.9: Transmission Limits

Report Description

Displays the transmission limits for all critical constraints in the IFM, HASP, and RTED markets. The term “critical” refers to being close to or at the limit. Transmission limits for critical constraints in other markets such as RTCD are not included.
Business Trigger

Trade Date + 3 days by 6:00 AM PPT.

Example:
- For Trade Date 9/12/2011,
- Report is accessible on 9/15/2011.

Layout

For illustrative purposes, the following is a sample listing report layout:

<table>
<thead>
<tr>
<th>GMT Interval</th>
<th>Constraint Name</th>
<th>Direction</th>
<th>Constraint Cause</th>
<th>Curve ID</th>
<th>Segment ID</th>
<th>Limit</th>
</tr>
</thead>
<tbody>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>CASCADE_ITC</td>
<td>Export</td>
<td>Base Case</td>
<td></td>
<td></td>
<td>300</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>SCE_PCT_IMP_BG</td>
<td>Import</td>
<td>Base Case</td>
<td></td>
<td></td>
<td>2000</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>34112_EXCHQEUR_115_34116_LE GR</td>
<td></td>
<td>Base Case</td>
<td></td>
<td></td>
<td>50</td>
</tr>
<tr>
<td>4/13/2012 11:00:00 AM</td>
<td>RAVENSWDSANMAT_NG_1</td>
<td>Base Case</td>
<td>1</td>
<td>1</td>
<td>300</td>
<td></td>
</tr>
</tbody>
</table>

Attributes

Listed below are the data elements contained in this report.

Note: the reports are contained in files accessed from the CAISO Portal.

<table>
<thead>
<tr>
<th>Attribute</th>
<th>High-Level Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>GMT Interval</td>
<td>Start time of the time interval (GMT)</td>
</tr>
<tr>
<td>Constraint Name</td>
<td>Name of transmission element, including interchanges, branches, branch groups, and nomograms.</td>
</tr>
<tr>
<td>Direction</td>
<td>For branch groups and interchanges, indicates whether the limit is in the import or export direction.</td>
</tr>
<tr>
<td>Constraint Case</td>
<td>For all transmission elements, indicates whether the limit is associated with a contingency or not. If a contingency is associated, the contingency name is displayed; otherwise “base case” is displayed.</td>
</tr>
<tr>
<td>Curve ID</td>
<td>For nomograms, indicates which curve ID the limit applies to.</td>
</tr>
<tr>
<td>Segment ID</td>
<td>For nomograms, indicates which segment ID the limit applies to.</td>
</tr>
<tr>
<td>Limit</td>
<td>The actual limit used on the transmission element for the market and interval.</td>
</tr>
</tbody>
</table>
10.3 SIBR Reports

Exhibit 10-3.1 summarizes the reports that are available to SCs through CAISO Portal for the DAM and RTM.

<table>
<thead>
<tr>
<th>Title</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Up to the minute transaction report</td>
<td>Hourly details on Bids that have been submitted to the Day-Ahead and</td>
</tr>
<tr>
<td>DAM/RTM</td>
<td>Real-Time Markets (to include SIBR generated Bids). The report</td>
</tr>
<tr>
<td></td>
<td>includes the time the Bid was received by CAISO, Bid status, submitted</td>
</tr>
<tr>
<td></td>
<td>by SC or CAISO and all Bid details broken out by resource type and</td>
</tr>
<tr>
<td></td>
<td>product type. This report should display the most current Bid that is</td>
</tr>
<tr>
<td></td>
<td>active in the market for which it was submitted. Detail of Clean Bids</td>
</tr>
<tr>
<td></td>
<td>produced by SIBR after the close of the Day-Ahead and Real-Time</td>
</tr>
<tr>
<td></td>
<td>Markets will indicate whether Clean Bid was submitted by the SC or</td>
</tr>
<tr>
<td></td>
<td>created by CAISO (SIBR).</td>
</tr>
<tr>
<td>Bid Activity Audit Report</td>
<td>Bid statuses of a Bid throughout its lifecycle broken out by Market type,</td>
</tr>
<tr>
<td>DAM/RTM</td>
<td>resource type and resource ID. Details include time received, Bid status,</td>
</tr>
<tr>
<td></td>
<td>whether submitted through GUI or web services and any relevant error</td>
</tr>
<tr>
<td></td>
<td>messages tied to the Bid by Bid status.</td>
</tr>
<tr>
<td>Self-Schedule Contracts Report</td>
<td>Hourly CRN Entitlement values for ETC/TOR contracts registered with the</td>
</tr>
<tr>
<td></td>
<td>CAISO. Note: CVR information will be displayed as an ETC (the difference</td>
</tr>
<tr>
<td></td>
<td>being the CRN is registered in MF based off of the TRTC Instructions</td>
</tr>
<tr>
<td></td>
<td>received which distinguishes it as a CVR.)</td>
</tr>
<tr>
<td>Distribution Location Reports</td>
<td>GDFs distribution locations and factors by hour for generating resources</td>
</tr>
<tr>
<td>DAM/RTM</td>
<td>for both the DAM and RTM</td>
</tr>
<tr>
<td>Trade Status Report</td>
<td>This report displays the status of Inter-SC Trades for the DAM and RTM.</td>
</tr>
<tr>
<td>DAM/RTM</td>
<td>This report closely mimics the information shown in the Inter-SC Trade</td>
</tr>
<tr>
<td></td>
<td>summary display in the SIBR UI. This report shows the most recent</td>
</tr>
<tr>
<td></td>
<td>status of an Inter-SC Trade in the market.</td>
</tr>
<tr>
<td>Trade Activity Audit Report</td>
<td>This report shows an audit trail of a trade by displaying all of its</td>
</tr>
<tr>
<td>DAM/RTM</td>
<td>associated statuses and error messages.</td>
</tr>
</tbody>
</table>
10.4 Archiving Policy

Exhibit 10-4 summarizes the archiving policy for reports identified in this section 10. Data will be available to market participants in accordance with this policy.

Exhibit 10-4: Archiving policy

<table>
<thead>
<tr>
<th>Reports</th>
<th>Policy</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reports listed in section 10.1, except the Conformed Dispatch Notice report.</td>
<td>Data will be available for 90 business days after it was published. The 90 day clock will be reset if data is corrected, for example due to a settlement rerun. This policy is applicable for both User Interface queries and API downloads.</td>
</tr>
<tr>
<td>Conformed Dispatch Notice report.</td>
<td>Data will be available for 3 years and 3 months from the end of each month. Example: All April 2012 Conformed Dispatch Notice data will be archived in July of 2015. This policy is applicable for both User Interface queries and API downloads.</td>
</tr>
<tr>
<td>Reports listed in section 10.2</td>
<td>Data will be available for 90 calendar days after it was published.</td>
</tr>
<tr>
<td>Reports listed in section 10.3</td>
<td>Data will be available for 7 calendar days after the applicable trade date (T+7). This policy is applicable for both User Interface queries and API downloads.</td>
</tr>
</tbody>
</table>
11. Dispatch Information/ADS

Welcome to the Dispatch Information section of CAISO BPM for Market Instruments. In this section you will find the following information:

- Application Function.
- Dispatch Instruction Cycle
- Dispatch Information
- Data Dictionary for ADS
- Technical Information for ADS

Automated Dispatching System (ADS) is the application developed by CAISO to communicate real-time dispatch instructions to Market Participants. Users of ADS are able to:

- Receive and generally respond to in-hour dispatch instructions in real-time.
- Receive confirmation of accepted pre-dispatch instructions
- Retain a local record of the transactions
- Query a database for historical instructions.

11.1 ADS Instruction Cycle

The typical ADS instruction cycle is as follows:

The RTM application determines the Energy needed to meet demand. An instruction list, in the form of a requested MW amount for each resource is generated from Ancillary Services and Energy Bids in the RTM.

The instruction list is transferred from RTM to the ADS system and is sent to the Market Participant.

The ADS system determines who has rights to view and to respond to each of the instructions and sends individual instructions to authorized ADS users based on the digital certificate (this will be the same certificate used for CAISO Portal access) used to login to ADS and the ADS Client associated with the certificate. Each ADS Client is associated with one or more resources and can have Primary, Secondary or Read only permissions on the identified resources.
Operation in the Hour-Ahead Scheduling Process (HASP)

For Intertie System Resources except Dynamic Resources and VERs, the user (with Primary or Secondary permissions) has the option to accept, partially accept or decline the instruction. The accept amount may be any value between zero and a MW threshold described in detail in the BPM for Market Operations. The user is allowed to provide a response or undo a response at any time within a 5 minute window.

If the user does not respond within the 5 minute window, ADS automatically responds with a "Timed–out" and the supplemental portion of the instruction will be forcibly accepted. The CAISO dispatcher may modify the response up until the close of the instruction cycle at 45 minutes after the hour.

For all other resource types, the dispatch is sent as an advisory. ADS automatically obtains an acknowledgement per instruction once it reaches the corresponding ADS client. For these resources, there is no opportunity to accept or decline the instruction.

Operation in the Fifteen Minute Market (FMM)

ADS will send Ancillary Services awards, Startup and Shutdown instructions, and dispatches. ADS automatically obtains an acknowledgement per instruction once it reaches the corresponding ADS client. For these resources, there is no opportunity to accept or decline the instruction through ADS, although the Scheduling Coordinator can change the FMM schedule to the extent possible through submission of an updated energy profile in its E-Tag. Ancillary Services awards and Startup and Shutdown instructions are binding. Dispatch instructions for these resources, although financially binding, should be treated as advisory as they may be modified in the Real-Time Dispatch.

Operation in the Real-Time Dispatch including Real-Time Contingency Dispatch (RTD, RTCD)

For all non-intertie resources, ADS automatically obtains an acknowledgement per instruction once it reaches the corresponding ADS client.

ADS automatically responds with an “accept”.

The user has approximately 90 seconds to review the instruction and is then expected to begin ramping to meet the instruction MW.
For example, an instruction is received by ADS at 1:31:00. The user must begin ramping the resource at 1:32:30 and reach the RT DOT MW at 1:37:30. The target time of 1:37:30 is labeled DOT Start Time on the ADS display.

Nevertheless, when the instruction is from RTCD in response to a contingency event, it is expected that resources respond and begin ramping to meet the instruction MW as soon as possible.

NOTE: If there are any known limitations to dispatchable resources, a outage management system ticket will need to be submitted prior to receiving Real Time dispatch instructions.

### 11.2 Dispatch Information Supplied by CAISO

The output information from the RTM applications that CAISO sends to ADS is listed in Exhibit 11-1.

**Exhibit 11-1: ADS Output**

<table>
<thead>
<tr>
<th>Application</th>
<th>Output</th>
</tr>
</thead>
<tbody>
<tr>
<td>HASP</td>
<td>Hourly Pre-dispatch for hourly block bid pre-dispatch resources</td>
</tr>
<tr>
<td></td>
<td>Hourly AS Awards for hourly block bid pre-dispatched resources</td>
</tr>
<tr>
<td>STUC</td>
<td>Binding start-up and shut-down instructions (looks ahead 4 hours beyond the Trading hour) (Can be Advisory or Binding depending on the resource limitations to meet start-up)</td>
</tr>
<tr>
<td>FMM</td>
<td>Binding start-up and shut-down instructions</td>
</tr>
<tr>
<td></td>
<td>Binding 15 minute AS Awards for all resources except Non-Dynamic System Resources submitting hourly block bids.</td>
</tr>
<tr>
<td>RTED</td>
<td>Binding five minute dispatch for five -min dispatchable resources</td>
</tr>
<tr>
<td>RTMD</td>
<td>Binding five minute Manual dispatch for five -min dispatchable resources</td>
</tr>
<tr>
<td>RTCD</td>
<td>Binding 10 minute contingency dispatch for five -min dispatchable resources</td>
</tr>
</tbody>
</table>

Please refer to section 2.3.2 Real Time Market Process of the *BPM for Market Operations* for a description of the HASP, STUC, RTUC, FMM, RTED, RTMD, and RTCD.
11.3 ADS DOT Breakdown

This is intended to clarify the various MW components in CAISO’s Automated Dispatch System (ADS) for the Dispatch Operating Target (DOT) breakdown. Relevant business functions and usages of these components are also described as well.

1. Business Purpose

The DOT breakdown that CAISO provides to market participants through ADS is to provide the energy component in terms of MW capacity constituting the DOT MW. It can be used for two different purposes:

1. Operational including, but not limited to, compliance checking, available operating reserve calculation, etc.
2. Shadow settlement.

Although these components are used to represent energy component of the DOT, they are calculated and represented in terms of MW capacity and hence they do not represent the energy difference due to ramping effect between intervals.

There are three types of real-time dispatch instructions that CAISO sends out through ADS, i.e., hourly pre-dispatch (HASP) instruction, Fifteen-Minute Market (FMM) and real-time dispatch (RTD) instruction. There are some subtle differences in how to interpret and use those MWs between those two types of instructions.

2. DOT Breakdown for Non-Dynamic System Resource Instruction

The following breakdown applies to Non-Dynamic inter-tie system resources. There are two critical components,

SCHED: The SCHED MW reflects the real-time energy self schedule for that resource in the SIBR clean bid;

SUPP: This MW is the difference between DOT and SCHED calculated by (DOT – SCHED). It is effectively the incremental (positive) or decremental (negative) from the self schedule MW.

Although the standard ramp RMPS is also calculated for the inter-tie resources in the DOT breakdown, the standard ramp has little relevance to the ultimate energy settlement of hourly pre-dispatched system resources since such energy is accounted for on a block basis. It is also worth mentioning that, there are two scenarios under which the SCHED will be equal to the final day-ahead energy schedule,
**Scenario 1**, for the market participants who elects to protect their day-ahead final energy schedule from IFM, i.e., the DA energy schedule MW is submitted as real-time self schedule;

**Scenario 2**: no explicit real-time energy bid curve or self schedule is submitted. SIBR will convert the final DA energy schedule into a real-time self schedule.

Following examples assume a real-time self schedule MW as 80MW,

- **Example 2.1** (incremental),
  DOT: 100MW
  DOT breakdown is,
  SCHED: +80MW
  SUPP: +20MW

- **Example 2.2** (decremental),
  DOT: 60MW
  DOT breakdown is,
  SCHED: +80MW
  SUPP: -20MW

2.1 **ADS Decline Functionality For Non-Dynamic System Resource Instruction**
In ADS, we allow the market participants to decline or partially accept a pre-dispatch instruction\(^{14}\). It is CAISO’s policy that any portion of the dispatch may be accepted, partially accepted, or fully declined. However the SCHED MW component cannot be changed after the HASP or FMM runs. A final accepted DOT is recorded in ADS and available to market participant as “Accept DOT”.

Decline/Partial Accept for example 2.1 (see previous section for example),
Assume the hourly MW threshold is 100 MW. Market participants can decline the 100 MW or partially accept any portion of the 100 MW. Therefore the Accept DOT will be any number between 0MW to 100MW.

\(^{14}\) Excessive declines of hourly block instructions for System Resources will be subject to penalties as defined in Section 11.31 of the Tariff. See the BPM for Settlements and Billing for more information.
Decline of 100 MW: Accept DOT will become 0 MW;
Partially acceptance of 90 MW out of 100: Accept DOT will become 90 MW;
Full acceptance of 100MW: Accept DOT will stay as 100MW.

Decline/Partial Accept for example 2.2,
Assume the hourly MW threshold is 80 MW.
Market participants can decline the -20MW or partially accept any portion of the -20MW, or even fully decline the entire instruction (i.e. zero). Therefore the Accept DOT will be any number between 0MW to 80MW.

Decline of -20 MW: Accept DOT will become 80 MW;
Full decline: Accept DOT will become 0 MW.
Partially acceptance of -10 MW out of -20: Accept DOT will become 70 MW;
Full acceptance of -20 MW: Accept DOT will stay as 60 MW.

3. DOT Breakdown for Generating Resources and Dynamic System Resources.
The following breakdown applies to all other resources besides Non-Dynamic System Resources, i.e., the generators, tie generators (including dynamic resources, pseudo ties and the resources used to model AS import on the ties) and participating loads (using the pump-storage model). There are five critical components here,

SCHED: The SCHED MW reflects the real-time self energy schedule for that resource in the SIBR clean bid;
SUPP: This MW is the difference between DOT and SCHED calculated by (DOT – SCHED). It reflects the incremental (positive) or decremental (negative) from the self schedule MW. SUPP is inclusive of the SPIN and NSPN MWs and MSSLF whichever applicable. For EIR, the difference between DOT and SCHED calculated by (DOT – FORECAST.)
SPIN: If this resource gets dispatched out of spin capacity (either in contingency or non-contingency mode15), this value will reflect dispatched SPIN capacity amount. Otherwise, this amount is zero. SPIN MW can be used for available reserve calculation;

15 Although it is not the scope of this document, it is worth mentioning that a contingency AS can only be dispatched in a contingency dispatch run or if the resource is flagged as contingency individually. A non-contingent AS can be dispatched in a normal real-time interval dispatch.
NSPN: If this resource gets dispatched out of non-spin capacity (either in contingency or non-contingency mode\textsuperscript{16}), this value will reflect dispatched Non-Spin capacity amount. Otherwise, this amount is zero. Non-SPIN MW can be used for available reserve calculation;

MSSLF: This only applies to MSS load following resources. If market participants submit MSS load following instructions for those resources, the validated load following instructions will be sent back through this component. For all non load following resources, this amount will be zero.

Although the standard ramp RMPS is also provided for the real-time dispatch instructions in the DOT breakdown, it is recommended the value of RMPS be determined outside of the dispatch instruction based on the standard ramp 20 minute cross-hour ramp between Day-Ahead schedules. It is also worth mentioning that, there are two scenarios under which the SCHED will be equal to the final day-ahead energy schedule,

\textbf{Scenario 1}, for the market participants who elects to protect their day-ahead final energy schedule from IFM, i.e., the DA energy schedule MW is used to submitted as real-time self schedule;

\textbf{Scenario 2}: no explicit real-time energy bid curve or self schedule is submitted. SIBR will convert the final DA energy schedule into a real-time self schedule.

Following examples assume a real-time self schedule MW as 80MW,

- Example 3.1 (incremental without dispatch out of Spin or Non-Spin),
  DOT: 100MW
  DOT breakdown is,
  SCHED: +80MW
  SUPP: +20MW

- Example 3.2 (incremental with dispatch out of Spin and Non-Spin),
  DOT: 100MW
  DOT breakdown is,
  SCHED: +80MW
  SUPP: +20MW
  SPIN: +5MW

\textsuperscript{16} See Note 1.
NSPN: +5MW

In example 3.2, the 5 MWs for dispatched out of Spin and Non-spin are part of the SUPP as the incremental amount. Besides the 5 MWs from Spin and Non-spin, it implies the $20 - 5 - 5 = 10MW$ as the market energy dispatch component.

- Example 3.3 (decremental),
DOT: 60MW
DOT breakdown is,
SCHED: +80MW
SUPP: -20MW

- Example 3.4 (incremental with dispatch out of Spin, Non-Spin And Load following),
DOT: 100MW
DOT breakdown is,
SCHED: +80MW
SUPP: +20MW
SPIN: +5MW
NSPN: +5MW
MSSLF: +5MW

In example 3.4, the 5 MWs for dispatched out of Spin, Non-spin and MSS load following are part of the SUPP as the incremental amount. Besides the 5 MWs from Spin, Non-spin and MSSLF, it implies the $20 - 5 - 5 - 5 = 5MW$ as the market energy dispatch component not associated with any other capacity.

- Example 3.5 (decremental with MSS load following),
DOT: 60MW
DOT breakdown is,
SCHED: +80MW
SUPP: -20MW
MSSLF: -5MW

In example 3.5, the -5 MWs for MSS load following are part of the SUPP as the decremental amount. Besides the -5 MWs from MSSLF, it implies the $-20 - (-5) = -15MW$ as the market energy dispatch component.
11.4 Technical Information for ADS

The ADS Technical information for the system will be made available on the CAISO Website. ADS Technical Information can be found at:  http://www.caiso.com/clientserv/ads/index.html

Technical information posted includes:

- User Documentation (installation and set up guides)
- API information, such as an interface specification with supporting WSDL and XSD files
- Business level documentation

Exceptional Dispatch Instruction Type Codes can be found at:
12. Public Market Information

Welcome to the Public Market Information section of CAISO BPM for Market Instruments. These reports are based on the requirements detailed in the CAISO Tariff Section 6.5, CAISO Communications.

In this section you will find the following information:

List of Report Tabs provided on the CAISO OASIS site. (http://oasis.caiso.com)

Content of the reports included under those Report Tabs

Interface Specifications regarding the downloading of the OASIS data through an API can be found at:

http://caiso.com/235f/235fcbd556310.html

CAISO provides the following reports groups through OASIS listed by the Tab name as they appear on the CAISO OASIS web site:

- Prices
- Transmission
- System Demand
- Energy
- Ancillary Services
- CRR
- Public Bids
- Atlas

12.1 Prices

CAISO provides information on prices to the public through the OASIS web page. The Price reports contain the following information:

**Locational Marginal Prices (LMP)** – Posts Hourly Locational Marginal Prices for all PNodes, APNodes and Scheduling Points in $/MWh, for the DAM and RUC market processes. Data fields are as follows:

LMP
• LMP Marginal Cost of Energy (MCE)
• LMP Marginal Cost of Congestion (MCC)
• LMP Marginal Cost of Losses (MCL)

Note: For the RUC prices, only the RUC price is posted. The three-component LMP breakdown is not applicable for RUC pricing.

**HASP Locational Marginal Prices (LMP)** – Posts hourly, the 4 15-minute advisory Locational Marginal Prices in $/MWh, for the HASP hour. Posts the LMP, plus the Congestion, Loss and Energy Components that make up the LMP.

➢ Note: In the event of HASP failure, HASP Pnode prices may not be available in OASIS. In this case, CAISO will not backfill these advisory prices.

Data fields are as follows:

LMP

• LMP Marginal Cost of Energy (MCE)
• LMP Marginal Cost of Congestion (MCC)
• LMP Marginal Cost of Losses (MCL)

**FMM Locational Marginal Prices (LMP)** – Posts on a 15-minute basis, the 15-minute financially binding Locational Marginal Prices in $/MWh, for the FMM market process. Posts the LMP, plus the Congestion, Loss and Energy Components that make up the LMP.

**Interval Locational Marginal Prices (LMP)** – Posts the five-minute Locational Marginal Prices for PNodes and APNodes in $/MWh, for each five-minute interval Real-Time Economic Dispatch (RTED). Data fields are as follows:

LMP

• LMP Marginal Cost of Energy (MCE)
• LMP Marginal Cost of Congestion (MCC)
• LMP Marginal Cost of Losses (MCL)
- Greenhouse Gas (GHG) \(^{17}\)

**Contingency Dispatch Locational Marginal Prices (LMP)** – Similar to the Interval Locational Marginal Prices (LMP) report, but for Real Time Contingency Dispatch (RTCD) runs.

Posts the ten-minute Locational Marginal Prices for PNodes and APNodes in $/MWh, for each ten-minute interval RTCD. Data fields are as follows:

LMP
- LMP Marginal Cost of Energy (MCE)
- LMP Marginal Cost of Congestion (MCC)
- LMP Marginal Cost of Losses (MCL)

**EIM Green House Gas Shadow Prices (GHG)** - Provides the Greenhouse Gas Shadow Price of the net imbalance energy export from all EIM Entity BAAs imported into the ISO BAA resulting from the Real-Time Market runs (RTPD and RTD).

**AS Clearing Prices** – Posts the Ancillary Services Marginal Price (ASMP) for all Ancillary Service types for all binding AS Regions. Posted hourly in $/MW for the DAM.

DAM - Hourly ASMP ($/MW)

**Interval AS Clearing Prices - Ancillary** Services Marginal Price (ASMP) for all Ancillary Service types for all binding AS Regions. Posts 15-Minute price relevant to the next 15 minute binding interval for RTM on a fifteen minute basis.

RTM - 15Min Binding ASMP ($/MW)

**Intertie Constraint Shadow Prices** – Posts the hourly constraint pricing at each Intertie-based Transmission Interface And Intertie Constraint, for each Market Process (DAM, HASP) in $/MWh, and the 15-Minute Shadow Price in $/MWh for the FMM. Report will also include an indication of whether the Constraints were binding because of the

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\(^{17}\) Greenhouse Gas component is only applicable to the Energy Imbalance Market (EIM)
base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

**Nomogram/Branch Shadow Prices** – Posts the hourly constraint pricing at each binding Nomogram and Branch, for each Market Process (DAM, HASP) in $/MWh, and the 15-Minute Shadow Price in $/MWh for the FMM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

**Fuel Prices** – For each Gas Flow Day, lists the gas price in $/MMBTU by fuel region.

**Current Locational Marginal Price** – This report is available for download only. Five minute Locational Marginal Prices for all PNodes and APNodes for the current interval. (Returns the most recently posted interval only) This download is provided to allow Oasis users to quickly receive the most current LMP without any prior intervals included in the payload.

**Interval Intertie Constraint Shadow Prices** – Posts the 5-Minute constraint pricing at Transmission Interfaces and Intertie Constraints in $/MWh, for the RTD run in the RTM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

**Contingency Dispatch Intertie Constraint Shadow Prices** – Similar to the Interval Intertie Constraint Shadow Prices report, but for Real Time Contingency Dispatch (RTCD) runs. Posts the 10-Minute constraint pricing at Transmission Interfaces and Intertie Constraints in $/MWh, for the RTCD run in the RTM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

**Interval Nomogram/Branch Shadow Prices** - Posts the 5-Minute constraint pricing at each Nomogram and Branch in $/MWh, for the RTD run in the RTM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

**Contingency Dispatch Nomogram/Branch Shadow Prices** - Similar to the Interval Nomogram/Branch Shadow Prices report, but for Real Time Contingency Dispatch (RTCD) runs. Posts the 10-Minute constraint pricing at each Nomogram and Branch in $/MWh, for the RTCD run in the RTM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.
**Reference Prices** – Posts Quarterly Reference prices associated with each Virtual Bidding PNode and APNode for supply and demand.

**Nodal Group Constraints Shadow Prices** - This report displays the upper and lower MW limits, cleared MW value and associated hourly shadowprices for any binding Nodal Group Constraint. This report is triggered with the publication of the Day-Ahead results.

**Flexible Ramping Constraint Results** – Posts the following values for RTUC and RTD market runs, for intervals when the Flexible Ramping Constraint is enforced.

- **Ramp Up Capacity (MW)** - The required amount of total un-loaded capacity below maximum operating limits (that can be dispatched up) of the ramp-limited resources that is retained through the market optimization. The Flexible Ramping Constraint is enforced on a system level per market run and market interval.

- **Ramp Up Shadow Price ($/MW)** - Shadow price of the ramping up constraint when binding in the relevant market run and in the binding market interval. Binding interval shadow price is the Ramp Up Shadow Price.

Payment to resources providing the flexi-ramp capacity will be paid based on the following price: For each applicable fifteen-minute FMM interval, the Flexible Ramping Constraint derived price will be equal to the lesser of: 1) $800/MWh; or 2) the greater of: (a) 0; (b) the Real-time Ancillary Services Marginal Price for Spinning Reserves for the applicable fifteen-minute FMM interval; or (c) the Flexible Ramping Constraint Shadow Price minus seventy-five percent of the maximum of (i) zero (0); or (ii) the Real-Time System Marginal Energy Cost, calculated as the simple average of the three five-minute Dispatch Interval System Marginal Energy Costs in the applicable fifteen-minute FMM interval.

The flexi-ramp cost for each binding FMM interval can be estimated by the amount of procured RAMP Up Capacity multiplied by the price described above in that binding interval. If the flexi-ramping constraint is binding and feasible, the procured Ramp Up Capacity is equal to the flexi-ramping capacity requirement (Ramp Up Capacity or RAMP_UP_CAP_REQ). However, if the flexi-ramping constraint is infeasible, meaning that the FMM market run is unable to procure the full required flexi-ramping capacity, the procured Ramp Up Capacity would be less than the flexi-ramping capacity requirement. On OASIS, the flexi-ramping capacity requirement not the procured amount is posted.

**MPM DA Locational Marginal Prices (LMP)** – Hourly Locational Marginal Prices from the Day-Ahead MPM run for all PNodes and APNodes associated with market resources with physical bids in $/MWh. Posts the LMP, including the competitive congestion component,
non-competitive congestion component, loss and energy components that make up the LMP.

**MPM RTM Locational Marginal Prices (LMP)** – 15-minute Locational Marginal Prices from the HASP and FMM MPM runs for all PNodes and APNodes associated with market resources with physical bids in $/MWh. Posts hourly for the 4 intervals of the HASP hour and every 15 minutes for FMM. Posts the LMP, plus the competitive congestion component, non-competitive congestion component, loss and energy components that make up the LMP.

**MPM Nomogram/Branch Group Shadow Prices** – Posts the constraint pricing at each binding nomogram and branch group, for each market process of the MPM run (DAM, HASP, FMM) in $/MWh. Posts hourly data for DAM and 15 minute data for HASP and FMM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

**MPM Nomogram/Branch Group Competitive Paths** – Posts the results of the dynamic competitive path determination, for binding nomogram and branch constraints for each market process of the MPM run (DAM, HASP, FMM) in $/MWh. Posts hourly data for DAM and 15 minute data for HASP and FMM and 5 minute for RTD. Posts a flag indicating whether each binding constraint was competitive or not.

**MPM Intertie Constraint Shadow Prices** – Posts the constraint pricing at Transmission Interfaces and Intertie Constraints, for each market process of the MPM run (DAM, HASP, FMM) in $/MWh. Posts hourly data for DAM and 15 minute data for HASP and FMM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

**MPM Intertie Constraint Competitive Paths** – Posts the results of the dynamic competitiveness constraint, for binding interchange, market scheduling limit, and branch group constraints for each market process of the MPM run (DAM, HASP, FMM, RTD). Posts hourly data for DAM and 15 minute data for HASP and FMM, and 5 minute for RTD. Posts a flag indicating whether each binding constraint was competitive or not.

**MPM Reference Bus** – Posts the reference bus used in the MPM run for each market process of the MPM run (DAM, HASP, FMM). Contains hourly data for the Day-Ahead market and 15-minute data for HASP and FMM. Note, the IFM, RUC, and regular HASP and FMM runs use a distributed reference bus.
**MPM Interval Reference Bus** - Posts the reference interval bus used in the MPM run for RTD. Contains 12 intervals data.

**Greenhouse Gas Allowance Prices** – Posts the index price for the greenhouse gas allowance in $/allowance.

Historical ACE Data – Pursuant to FERC Order 784; 18 C.F.R § 385.37.6(k), the CAISO will post on OASIS historical one-minute and ten-minute area control error data for the most recent calendar year, and update this posting once per year. The CAISO will post this annual data by the end of January for the previous year.

**Scheduling Constraint Shadow Prices** - This report will provide the shadow prices created by scheduling constraints, examples of these are: BAA POWER BALANCE, BAA TRANSFER DISTRIBUTION, BAA TRANSFER LOWER LIMIT, BAA TRANSFER UPPER LIMIT, ETSR LOWER LIMIT, ETSR TRANSMISSION COST, ETSR UPPER LIMIT, etc.

### 12.2 Transmission

The Transmission reports contain the following information:

**Note, the Current Transmission Usage, Transmission Interface Usage, and Market Available Transfer Capacity reports use the following ATC calculation formula:**

\[
ATC = \text{hourly TTC} - \text{CBM} - \text{total TRM} - \text{AS from imports} - \text{scheduled net energy from imports/exports} - \text{hourly unscheduled transmission rights capacity, where:}
\]

- **Hourly TTC = seasonal TTC - constraints**

- **Total TRM = TRM due to unscheduled loop flow + TRM due to transmission topology uncertainty + TRM due to simultaneous path interaction.**

Market Transfer Capability = Seasonal TTC-TRM-Costraint

**Current Transmission Usage** - Consolidated report for current transmission capacity and usage per Transmission Interface. Starts with known constraints and transmission rights 7-days ahead of the trade date. The TTC and constraint values are updated as outages occur. The ancillary services, scheduled
net energy, and unused transmission rights capacity values are updated in conjunction with
the publication of the DAM and RTM market results.

**Transmission Interface Usage** – Consolidated report for transmission capacity,
constraints, ETC/TOR utilization and market schedules resulting from CAISO market
systems for DAM HASP, or FMM. Posted by Transmission Interface.

**Market Available Transfer Capacity** – Available Transfer Capacity per Transmission
Interface by direction, for market processes DAM, HASP, or FMM expressed in MW.

**Transmission Outages** - Lists planned and actual Transmission Outage events per
Transmission Interface by direction. The list is updated with every outage event. List
includes: Outage description, Outage start-time and end time, rating of the curtailed line,
Outage notes.

**EIM Transfer Limits** - Provides the EIM Transfer low and high limits per each EIM Entity
Balancing Authority Area and EIM Entity Balancing Authority Area group, resulting from the
Real-Time Market runs (RTPD and RTD).
• Low limit indicates the minimum capacity that can be transferred from each EIM Entity
Balancing Authority Area and EIM Entity Balancing Authority Area group
• High limit indicates the maximum capacity that can be transferred from each EIM Entity
Balancing Authority Area and EIM Entity Balancing Authority Area group.

**EIM Transfer** - Provides the EIM Transfer mw per each EIM Entity Balancing Authority Area
and EIM Entity Balancing Authority Area group, resulting from the Real-Time Market runs
(RTPD and RTD).

**EIM BAA Base NSI (ENE_BASE_NSI)**
A new report that provides the Net Scheduled Interchange (NSI) results for the real-time
binding intervals, based on the last T-40 snapshot base schedules per Balancing Authority
Area.

**EIM BAA Dynamic NSI (ENE_EIM_DYN_NSI)**
A new report that provides the Net Scheduled Interchange (NSI) results based on real-time
market runs (RTPD and RTD) per Balancing Authority Area.

### 12.3 System Demand

The System Demand reports contain the following information:

**CAISO Peak Demand Forecast** – Lists the Peak CAISO Forecast of CAISO Demand,
starting 7 days before Trading Day, including Peak Demand (MW) and Peak Time (Hour)
Updated daily at 0900 hours. Also posts Peak Demand Forecast by TAC Area (including MSS).

**CAISO Demand Forecast** – Lists the CAISO Forecast of CAISO Demand starting seven days before the Trading Day. Includes an hourly Demand Forecast seven days and two days prior to the Trading Day (7-DA and 2-DA), an hourly DA market forecast, a RTUC 15-minute forecast (including operator adjustments) an RTD five-minute Demand Forecast (also including operator adjustments), and a total actual hourly integrated Demand, all expressed in MW. Posted by TAC Area as well as the total system level.

The RTM 5-Minute Load Forecast is posted for the next 11 intervals. Postings occur every 5-minutes for a rolling 11 interval period.

**Wind and Solar Forecast** - Forecast and actual wind and solar generation. Aggregated by trading hub (NP15, ZP26, and SP15). Day-Ahead forecast is posted daily in advance of the Day-Ahead Market, Hour-Ahead forecast is posted in advance of each HASP market run of the RTM, both by hourly intervals. FMM forecast is posted in advance of each FMM market run by 15-minute intervals. RTD forecast is posted in advance of each RTED run by 5-minute intervals. Actual production is posted the day after the operating day. Note: to ensure a high level of accuracy only Eligible Intermittent Resources (EIR), including those that participate in the Participating Intermittent Resource program (PIRP) are included in the report.

**Advisory CAISO Demand Forecast** – This report will provide the demand forecast for the first advisory interval resulting from each of the RTPD/15min and RTD/5min market runs, for the CAISO-TAC and other balancing authority areas (BAA).

**Sufficiency Evaluation Demand Forecast** - This report will provide the hourly and 15-minute unbiased demand forecast. The report will display 24 hours of forecast with hourly and 15-minutes granularity for each publication time, and will retain a total of seven days only.

### 12.4 Energy

The Energy reports contain the following information:
System Load and Resource Schedules

DAM Load, Generation, Import and Export Schedules per TAC Area and CAISO total for each Operating Hour, in MW.

RUC Capacity from Generation and Imports for each TAC Area, plus CAISO total for each Operating Hour, in MW.

Hourly Real-Time Market (HASP) Generation, Import and Export per TAC Area and CAISO total, in MW.

5 minute RTM Generation, Import and Export per TAC Area and CAISO total, in MW.

(Note: Dynamic imports is counted as IMPORTs, instead of GENERATION schedules)

Contingency Dispatch Resource Schedules – Similar to the System Load and Resource Schedules report, but for Real Time Contingency Dispatch (RTCD) runs.

RTM Generation, Import and Export per TAC Area and CAISO total, in MW for all 10-minute RTCD runs.


Addition of two new expected energy type codes applicable for EIM resources:
• BASE - real-time expected energy based on the base schedules
• MDE - manual dispatch energy signals

Please refer to the table in the BPM for Market Operations, Appendix C.4 for the complete list of valid Expected Energy Types.

Exceptional Dispatch – Summary of Exceptional Dispatch Energy for each Operating Hour, expressed in MWh, and Exceptional Dispatch weighted price, in $/MWh. Posted daily at T+1. Values are summed by Exceptional Dispatch Type, by TAC Area.

Please refer to the BPM for Market Operations, Appendix C.4 for the complete list of valid Exceptional Dispatch Types.

Market Power Mitigation Status - Mitigation indicator showing whether any Bids were replaced by Reference Curves, for the following: DAM Hourly Market Mitigation (Yes/No), HASP and FMM 15Min Market Mitigation (Yes/No), and RTD (Yes/No).
Addition of a new element “Balancing Authority Area” (BAA) identifier in which the day-ahead/real-time mitigation results are defined.

**RMR** – Lists manually and MPM determined RMR summed across resources, for each Market, including DAM RMR Capacity available, DAM manual dispatched RMR Capacity, HASP RMR Capacity available, and HASP manual dispatched RMR Capacity.

**Marginal Losses** – Lists the total system Marginal Loss costs ($) and total system losses (MWh) for the DAM and HASP Runoff RTM.

**Resource Adequacy Minimum Load** – Posts at T+1, for both total CAISO committed, and total CAISO RA committed. Posts for the DAM, RUC and RTM plus the Totals across all markets, the following values:

- Capacity committed
- Number of units committed
- Minimum Load Cost ($)
- Start-Up Cost ($)
- Minimum Load (MW) (CAISO committed total only).


**Day Ahead Market Summary Report** - Posts the summary of the Day Ahead Market showing physical and virtual breakdowns of energy submitted, dollars submitted, energy cleared and dollars cleared as well as the totals. The report is grouped by supply, demand, exports and imports categories. This report will post after the completion of the Day Ahead Market publication.

**Net Cleared Convergence Bidding Awards** - Posts Net Cleared MW for Virtual Bids for every Virtual Bidding Node per Trade Hour within a Trading Day including Trading Hubs and default LAPs. This report will post after all Real Time markets have closed for the associated Trading Day.

Posts Convergence Bidding Supply Awards, Less Convergence Bidding Demand Awards per node. Under this convention, positive net cleared virtual quantities will
indicate net Virtual Supply, whereas negative net cleared virtual quantities will indicate net Virtual Demand at a given node.

A value of null Net Cleared Virtual quantities at a given node will indicate no virtual bids submitted at that node while a value of zero will indicate virtual supply and demand Awards netted to zero.

**Convergence Bidding Nodal MW Limits** - Posts the MW limits used by the ISO in formulating nodal MW constraints used as needed to help ensure an AC solution. An upper and lower limit is defined for each Eligible Pnode other than an Eligible Pnode established for an Intertie. This report is triggered with the publication of the Day-Ahead results.

**Aggregated Generation Outages** - Generator de-rates and outages which are considered in the Day-Ahead Market. Report is generated from the list of de-rates and outages that are known at the time of publication, typically 5:00 AM PPT the day prior to the operating day. Aggregated into a total MW capacity reduction amount by trading hub (NP15, ZP26, and SP15) and fuel category (thermal, hydro, renewable). The thermal fuel category includes gas, oil, nuclear, biomass, and waste fuel types. For ZP26 the resources are aggregated into a single category, due to low counts of hydro and renewable resources.

**EIM BAA Hourly Base NSI** - This report will provide the hourly base net scheduled interchange (NSI) for each of the balancing authority areas at the T-40, T-55, and T-75 timeframes.

**EIM BAA Hourly Base Loss** - This report will provide the hourly base loss for each of the balancing authority areas at the T-40, T-55, and T-75 timeframes.

**EIM Transfer Limits** - Provides the EIM Transfer low and high limits per EIM Balancing Authority Area group, resulting from the real-time market runs (RTPD and RTD).

- Low limit indicates the minimum limit that can be transferred from a group
- High limit indicates the maximum limit that can be transferred from a group

Starting with the fall 2015 EIM year 1 activation, this report will no longer be populated with the high and low limits per BAA group. EIM transfer limits information will be available on the Tie level, via the new report “EIM Transfer Limits by Tie”.

**EIM Transfer** - Provides the Energy Imbalance Market (EIM) Transfer mw per EIM Balancing Authority Area Group, resulting from the real-time market runs (RTPD and RTD).

**EIM BAA Dynamic NSI** - Provides the Net Scheduled Interchange (NSI) results based on real-time market runs (RTPD and RTD) per Balancing Authority Area.
**EIM BAA Base NSI** - Provides the Net Scheduled Interchange (NSI) results for the real-time binding intervals, based on the last T-40 snapshot base schedules per Balancing Authority Area.

**EIM Transfer Limits By Tie** - Provides the Energy Imbalance Market (EIM) effective energy transfer limit mw of the energy transfer across the tie, resulting from the real-time market runs (FMM/RTPD and RTD).

**EIM Transfer By Tie** - Provides the Energy Imbalance Market (EIM) transfer mw across the tie, resulting from the real-time market runs (FMM/RTPD and RTD).

**Wind and Solar Summary** - Provides the hourly aggregated day-ahead market schedules, hourly day-ahead aggregated forecasts, and hourly average real-time market schedules for all the variable energy resources (VER); plus hourly net virtual (total virtual supply minus total virtual demand awards).

**Flexible Ramp Surplus Demand Curves** - This report will provide the RTPD/15minute and RTD/5-minute interval flexible ramping up/down surplus demand curve composed of 11 mw and $/mwh pairs, for each balancing authority areas (BAA) and the EIM Area.

**Flexible Ramp Aggregated Awards** - This report will provide the flexible ramping up/down aggregated award totals (MW) for each balancing authority areas (BAA) and the EIM Area, resulting from RTPD/15minute and RTD/5-minute market runs.

**Uncertainty Movement by Category** - This report will provide the RTD/5min Uncertainty Movement (mw) for each resource category (Supply, Intertie, and Load) by BAA and EIM Area (each defined as a BAA Group)

**Flexible Ramp Requirements** - This report contains balancing authority area-level 15-minute interval data starting on trade date 12/23/2015. Additional information about this report:

- **Flexible Ramp Constraint Requirement** is the minimum 15-minute capacity required to meet the flexible ramp constraint for a particular balancing authority area.

- **Flexible Ramp Sufficiency Test Requirement** is an unadjusted amount comprised of two components: uncertainty and net demand movement. The total flexible ramp sufficiency test requirement for a given 15-minute interval is equal to the cumulative sum of the net demand movement for the subject hour up to the corresponding 15-minute interval plus the uncertainty component for the given 15-minute interval. The sum requirement is before diversity benefits, export credits, and net import capability are considered.
• *Net Demand Movement Component* is the movement of the forecasted load minus the movement of the forecasted solar and wind power generated minus the change in the net scheduled interchange.
• *Uncertainty Component* is equal to the unadjusted Flexible Ramp Constraint Requirement. It represents the 95th percentile range of upward movement in the 5-minute market compared to the 15-minute market.

Flexible Ramping Product initiative will be active on 11/1/2016, the following report columns will be null:
• Flexible Ramp Constraint Requirement (mw)
• Flexible Ramp Sufficiency Test Requirement’s Net Demand Movement Component

The Flexible Ramp Product Uncertainty Component value will continue to be published, for both “UP” and “DOWN” Ramp Types based on the Histogram for RTD & FMM.

### 12.5 Ancillary Services

The Ancillary Services Report contains the following information:

**AS Requirements** – Lists the Ancillary Service capacity minimum and maximums per AS type, per AS Region, to be procured or self-provided in each Operating Hour. Posts for the 2-DA Forecast, DAM HASP and FMM.

- For the 2-DA Forecast, the Maximum requirement for Spin, Non-Spin and Regulation Up will be posted by Upward AS total. The Minimum values will be posted by individual AS product type.
- When encountering a max A/S limit of zero, please interpret this as "no limit" set.

**AS Results** – Ancillary Service Capacity awarded and self-provided, by AS type, posted for each AS Region. Also posts the sum of the procured and self-scheduled. Posts hourly results for the Day-Ahead (DAM) and HASP markets, and 15 Minute results for the FMM, by resource type. Also posts Total AS Cost for each AS Region, by AS Type.

- Results will only post for AS Regions that are binding for that market run.

**Actual Operating Reserves** – Lists total actual Demand, AS, and Operating Reserves maintained during delivery (as a % of Load).

**Mileage Calculation Components** – Lists average Instructed Mileage (MW) from the prior seven days for each hour of a trading day. Posted daily.
12.6 CRR

The CRR Reports contains the following information:

**CRR Clearing Prices** – Congestion Revenue Rights auction clearing prices ($/MW) by PNode

**CRR Inventory** – Congestion Revenue Rights Daily inventory, including:

- Market Term (long-term, short-term)
- Time of use
- Start-time and end-time
- CRR type
- CRR category
- CRR Option (yes/no)
- Source APNode
- Sink APNode
- MW amount
- Owner ID

12.7 Public Bids

This is a download-only data report that provides the Clean Bid payloads used by the markets, with certain fields modified for confidentiality. This report is provided at T+90, as defined in CAISO Tariff section 6.5.6.1.1 The Public Bids Reports contain the following information:

Clean Bid payloads used in the markets, with certain fields replaced by pseudo data as indicated; posted for DAM and RTM. and posted at T+90. The Public Bid Data is downloadable to XML and CSV only, for a single day at a time.
Convergence Bidding Public Bids – Posts Virtual Bidding results from the Clean Bid payloads for the DAM, with the SC ID and Node ID replaced with pseudo values. Posted at T+90. The Virtual Bidding Public Bid Data is downloadable to XML and CSV only, for a single day at a time.

Congestion Revenue Rights (CRR) Public Bids - Bids submitted and used in the CRR auction markets, with certain fields replaced by pseudo data as indicated. Posted for the monthly auctions 90 days after the close of markets and seasonal auctions after each relevant quarter has passed. The Public Bid Data is downloadable to XML and CSV only, for a single market at a time.

12.8 Atlas

The Atlas Report includes the following information:

PNode Listing – List all pricing locations. Complete Network PNode Listing including PNode IDs and effective dates of operation. For Virtual Bidding purposes, the report also displays an indicator of whether or not the PNode is eligible for Virtual Bidding, the maximum MW Limit associated with each PNode as well as the effective start and end date for the limit. Maximum MW limits will not be posted for PNodes associated with Interties.

APNode Listing – Lists All Aggregated Pricing Node locations used in CAISO Markets. For Virtual Bidding purposes, the report also displays an indicator of whether or not the APNode is eligible for CB, the maximum MW Limit associated with each APNode as well as the effective start and end date for the limit. Maximum MW limits will not be posted for APNodes associated with Interties.

Load Distribution Factors (LDFs) – Lists typical participation factors that map PNodes to APNodes.

Load Aggregation Point Listing – List of all Load Aggregation Points in CAISO, by type. Includes APNode ID, APNode Type, and effective dates of operation.
**Market Resource Listing** – List of CAISO Resources. Including Generating Unit ID, PNode, aggregation type, resource type, effective dates.\(^{18}\)

**Trading Hub Listing** – lists all Trading Hub APNodes in CAISO; APNode ID, and effective dates.

**Trading Hub – PNode Mapping** – Map of all PNodes to each Trading Hub APNode.

**Ancillary Service Region – PNode Mapping** - Map of all PNodes to each Ancillary Services Region and Sub-Region.

**RUC Zone - PNode Mapping** - Map of all PNodes to each Reliability Unit Commitment Zone.

**TAC Area - PNode Mapping** – Map of all PNodes to each Transmission Access Charge Area.

**Intertie Constraint Mapping** – Map of all Intertie Constraints with respective Transmission Interfaces and TSIN Registered entity ID.

**Transmission Interface Listing** – Lists all Transmission Interfaces in CAISO, including Transmission Interface ID, Type, WECC Path, effective dates

**Peak/Off-Peak Definition** – Posts Hourly Peak/.Off-Peak indicator based on the WECC definition.

**Publications and Revisions** - OASIS data publication and revision. Includes publication date, publication type, operating date hour min, description, version, status, and comments. This report will log publication events for all public market data posted to the CASIO OASIS site.

**OASIS Publication Schedule** – Contains the usual schedule by which all other OASIS data entities are published. This includes publication type, publication interval, publication time, description, report group, and comments.

**System Operating Messages** - System Operating Messages including message time, Severity, and message text.

Price Correction Messages: Messages related to price corrections; this includes market type, publication time and message text.

\(^{18}\) This listing does NOT include Load Resources – this is covered by the Load Aggregation Point listing.
**Scheduling Point Definition** - Lists all of the scheduling points and its balancing authority area, also includes a designation if the scheduling point is a location where market intertie bids can be submitted onto.

**BAA and Tie Definition** - Lists all of the ties and the balancing authority areas it is connected from/to; also includes a designation if Energy Imbalance Market (EIM) occurs on the tie.

**Scheduling Point and Tie Definition** - Lists all the scheduling points associated with the tie.

**Intertie Constraint and Scheduling Point Mapping** - Lists all the intertie constraints associated with the scheduling points.

**Intertie Scheduling Limit and Tie Mapping** - Lists all the intertie scheduling limits associated with the tie.
Attachment A

BID VALIDATION RULES
A Bid Validation Rules

Please refer to the following links to the latest versions of the SIBR Rules:


Under the Applications Documentation

Select either:

Scheduling Infrastructure Business Rules (SIBR): Bidding or

Scheduling Infrastructure Business Rules (SIBR): Inter-SC Trades

Technical Specifications can also be found on the above links.
Attachment B

MASTER FILE UPDATE PROCEDURES
B Master File Update Procedures

B.1 Master File

The Master File (MF) contains data for resources participating in CAISO markets. The data is used by CAISO market systems for bidding, operation, and settlement. The authorized Scheduling Coordinator (SC) can submit a request to update specific operating parameters for existing generator or intertie resources by submitting a revised Resource Data Template (RDT) via the Master File User Interface (UI) or the Master File Application Programming Interface (API). This can be done for Generator resources on the Generating Resource Data Template (GRDT) or Intertie resources on the Intertie Resource Data Template (IRDT). Some data elements in the RDT are updateable via the UI, while others must be updated through some other process. Details are provided in the following tables.

Once the SC has submitted a request, the Master File analyst reviews the request and determines if the updates comply with stated MF business rules. If the updates pass the initial review, the request is presented for further review and approval by affected CAISO systems. The changes must be approved prior to them being made effective within the Master File database. If there are questions regarding the requested updates, the CAISO will contact the SC to coordinate modifications to the requested updates.

Master File change requests require at least five (5) and up to eleven (11) business days, depending on the complexity of the change, from receipt of the request to implementation into the Master File database (except as otherwise prescribed, such as to accommodate a high volume of requests.) If the RDT fails a business rule or the SC chooses to recall their RDT request and make a different change, the 5-business day clock begins again upon resubmission.

B.2 Generator Resource Data Template

The GRDT is an Excel spreadsheet containing multiple worksheet tabs, which contain static resource characteristics stored in the CAISO database. The worksheet tabs listed in the table below are described in the following sections:
<table>
<thead>
<tr>
<th>Spreadsheet Tab</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Instruction</td>
<td>Contains report details</td>
</tr>
<tr>
<td>Definition-GRDT</td>
<td>Link to blank template on CAISO website</td>
</tr>
<tr>
<td>Code</td>
<td>Blank</td>
</tr>
<tr>
<td>RESOURCE</td>
<td>Resource data</td>
</tr>
<tr>
<td>RAMPRATE</td>
<td>Resource ramp rate</td>
</tr>
<tr>
<td>HEATRATE</td>
<td>Resource heat rate</td>
</tr>
<tr>
<td>STARTUP</td>
<td>Resource start-up data</td>
</tr>
<tr>
<td>FORBIDDEN OPR REGION</td>
<td>Resource forbidden operating region</td>
</tr>
<tr>
<td>REGULATION</td>
<td>Resource regulation range</td>
</tr>
<tr>
<td>REG RAMP</td>
<td>Resource regulation ramp rate</td>
</tr>
<tr>
<td>OP RES RAMP</td>
<td>Resource operating reserve ramp rate</td>
</tr>
<tr>
<td>MSG_CONFIG</td>
<td>MSG Configuration detail</td>
</tr>
<tr>
<td>TRANSITION</td>
<td>Details of transitions between configurations</td>
</tr>
<tr>
<td>CONFIG_RAMP</td>
<td>Configuration ramp rate</td>
</tr>
<tr>
<td>CONFIG_HEAT</td>
<td>Configuration heat rate</td>
</tr>
<tr>
<td>CONFIG_STRT</td>
<td>Configuration start-up detail</td>
</tr>
<tr>
<td>CONFIG_REG</td>
<td>Configuration regulation range</td>
</tr>
<tr>
<td>CONFIG_RREG</td>
<td>Configuration regulation ramp rate</td>
</tr>
<tr>
<td>CONFIG_ROPR</td>
<td>Configuration operating reserve ramp rate</td>
</tr>
<tr>
<td>GEN_RES_AGGR</td>
<td>Child Resources of Aggregate Resource</td>
</tr>
</tbody>
</table>

**B.2.1 RESOURCE tab – Modifiable Data**

Many of the data elements in the Resource tab are modifiable via the RDT update process, by submitting a revised RDT through the Master File User Interface. Those data elements are described in the following table in the order they appear in the GRDT. Non-modifiable fields are described in the next section.
<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
</table>
| MAX_GEN (Maximum Generation Capacity) | MW | The Net Dependable Capacity (NDC or PMAX) a Generator Resource can produce on a sustained basis as measured at or compensated to the Generating Unit's defined point of delivery. For PDR resources - the maximum load that can be curtailed. For LESR resources - the maximum capacity when discharging at maximum sustainable rate. For DDR resources - the maximum capacity (negative or zero) represents the lowest load level it can be reduced to. | • Cannot be null  
• Must equal the maximum output level (last segment) in the RAMP and HEAT curves  
• Cannot be greater than the tested Pmax (if unit was tested).  
• Must be >= MIN_GEN + 0.01 |
| MIN_GEN (Minimum Generation Capacity) | MW | The minimum output level at which a Generator Unit can operate on a sustained basis. For PDR resources - the smallest increment that can be curtailed. For LESR resources - the minimum capacity when discharging at maximum sustainable rate. For DDR resources - minimum capacity (negative) represents the maximum load level at which it can consume energy. | • Cannot be null  
• Must be 0 or >= 0.1 if FUEL_TYPE <> LESR, DDR  
• Must equal the minimum output level (segment 1) in the RAMP curve and in the HEAT curves  
• Must be <= MAX_GEN - 0.01 |
| MIN_DISP_LEVEL (Minimum Dispatchable Level) | MW | The Minimum operating level at which a Generating Unit is able to readily respond to a dispatch instruction. For PDR and NGR resources, this value is the same as MIN_GEN. | • Default value is set equal to MIN_GEN  
• Must be greater than or equal to MIN_GEN  
• If MIN_DISP_LEVEL > MIN_GEN, a Forbidden Region should be specified between MIN_GEN and MIN_DISP_LEVEL. |
<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
</table>
| MIN_ON          | Minutes    | The minimum amount of time that a Generating Unit must stay on-line after starting up and reaching PMin, prior to being shut down, due to physical operating constraints. In case of a Pump Storage resource, this field represents the minimum time that the resource must stay on-line in the generating mode prior to being shut down. If no constraint, then leave this field blank, or 0 if resource is Gas-fueled. For PDR resources - Minimum amount of time the PDR resource can maintain a curtailment, once called to be curtailed. For NGR resources the field is not applicable and must be set to 0. | • Cannot be null if Fuel Type is equal to GAS; 0 is okay.  
• For RDR, must be <= 60 |
| MAX_ON          | Minutes    | This data element is not used - Market software does not reference this data element.                                                                                                                    |                                                                                                         |
| MIN_OFF         | Minutes    | The minimum amount of time that a Generating Unit must stay off-line after being shut down, due to physical operating constraints. In case of a Pump Storage resource, this field represents the minimum time that the resource must stay off-line after being shut down from the generating mode prior to being started again in the generating mode. Minimum Off Time includes Startup Time. For PDR - Minimum time after a load restoration before load can be curtailed again, includes Startup Time. | • Must be greater than or equal to the minimum startup time (segment 1) in the startup curve |
| MAX_STRT        | starts/day | The maximum number of times a Generating Unit can be started up within one day, due to environmental or physical operating constraints. For PDR, this is the maximum number of curtailments per day. For NGR resources the field is not applicable. | • Must be an integer (whole number), 1 or greater |
| MIN_LOAD_COST   | $/hour     | The costs a Generating Unit or a Participating Load incurs operating at minimum load. The value is needed for a resource with the Cost Basis of Registered Cost (fixed value) only.  
For PDR - the cost to curtail at the PDR resource's MIN_GEN level per hour. For NGR resources the field is not applicable and must be set to 0. | • Cannot be null if ML Cost Basis Type of REGC (Registered) is selected  
• May not exceed 150% of unit's projected proxy cost for minimum load cost if ML_COST_BASIS_TYPE = REGC |
<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
</table>
| ML_COST_BASIS_TYPE | Text       | Election for Minimum Load Cost calculation methodology used in the bid. Options are Proxy (PRXC) or Registered (REGC). Only Use Limited resources are eligible to elect Registered methodology. If Registered Cost: Please refer to Attachment G. | • If REGC is selected, Minimum Load Cost value must be provided  
• For REGC to be selected, USE_LIMIT flag must be Y |
| SU_COST_BASIS_TYPE | Text       | Election for Startup Cost calculation methodology used in the bid. Options are Proxy (PRXC) or Registered (REGC). Only Use Limited resources are eligible to elect Registered methodology. If Registered Cost: Please refer to Attachment G | • If REGC is selected, Startup Cost value must be provided  
• For REGC to be selected, USE_LIMIT flag must be Y |
<p>| MAX_PUMP         | MW         | The Maximum Operating Level of a Pump or a Pumped-Storage-Hydro Unit operating as a hydro pump                                                                                                               | • Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP |</p>
<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>MIN_DWN_TM_PG</td>
<td>minutes</td>
<td>The Pump-to-Gen minimum down time applies to Pump Storage Resources and reflects the minimum time (in minutes) that the resource must be offline (or self-scheduled) after being de-committed from pumping mode and before being dispatched in generation mode.</td>
<td></td>
</tr>
<tr>
<td>MAX_PUMP_SD_CST</td>
<td>$/shutdown</td>
<td>The maximum cost it would take to shut down the pump.</td>
<td></td>
</tr>
<tr>
<td>PUMP_SHTDWN_TM</td>
<td>minutes</td>
<td>The pump shutdown time</td>
<td></td>
</tr>
<tr>
<td>COST_RANK_LMPM</td>
<td>1, 2, 3</td>
<td>A method of calculating Default energy bids based on fuel costs and variable operations and maintenance costs.</td>
<td>Only one of the three ranking fields (COST_RANK_LMPM, NEGO_RANK_LMPM, and PRC_RANK_LMPM) can be ranked as 1.</td>
</tr>
<tr>
<td>NEGO_RANK_LMPM</td>
<td>1, 2, 3</td>
<td>A method of calculating Default energy bids based on a negotiation with the CAISO or an Independent Entity.</td>
<td>Only one of the three ranking fields (COST_RANK_LMPM, NEGO_RANK_LMPM, and PRC_RANK_LMPM) can be ranked as 1.</td>
</tr>
<tr>
<td>PRC_RANK_LMPM</td>
<td>1, 2, 3</td>
<td>A method of calculating Default energy bids based Locational Marginal Prices.</td>
<td>Only one of the three ranking fields (COST_RANK_LMPM, NEGO_RANK_LMPM, and PRC_RANK_LMPM) can be ranked as 1.</td>
</tr>
<tr>
<td>RSRV_CAP_SPIN</td>
<td>MW</td>
<td>The portion of unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and that is capable of running for at least two hours.</td>
<td>Must have a value if CERT_SPIN is Y. Cannot be greater than the tested Spin capacity. Must be &lt;= (MAX_GEN - MIN_GEN)</td>
</tr>
<tr>
<td>RDT Column Name</td>
<td>Unit</td>
<td>Definition</td>
<td>Business Rule</td>
</tr>
<tr>
<td>----------------</td>
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<td>------------</td>
<td>---------------</td>
</tr>
<tr>
<td>RSRV_CAP_NSPIN (Reserve Capacity: Non-Spin)</td>
<td>MW</td>
<td>The portion of off-line generating capacity that is capable of being synchronized and Ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least two hours.</td>
<td>• Must have a value if CERT_NSPIN_DAM and CERT_NSPIN_RTM flags are set to Y. • Cannot be greater than the tested Non-spin capacity. • Must be &lt;= MAX_GEN</td>
</tr>
<tr>
<td>CERT_REG_DOWN (Certified for AS: Regulation Down)</td>
<td>Y/N</td>
<td>An identifier of a resource that is certified to provide Regulation Down</td>
<td>• If Y, the REG and RREG curves must be defined</td>
</tr>
<tr>
<td>CERT_REG_UP (Certified for AS: Regulation Up)</td>
<td>Y/N</td>
<td>An identifier of a resource that is certified to provide Regulation Up</td>
<td>• If Y, the REG and RREG curves must be defined</td>
</tr>
<tr>
<td>CERT_SPIN (Certified for AS: Spin)</td>
<td>Y/N</td>
<td>An identifier of a resource that is certified to provide Spinning Reserve.</td>
<td>• If Y, RSRV_CAP_NSPIN must have a value and the ROPR curve must be defined</td>
</tr>
<tr>
<td>CERT_NSPIN_DAM (Certified for AS DAM: Non-Spin)</td>
<td>Y/N</td>
<td>An identifier of a resource that is certified to provide Non-Spinning Reserve in the DAM.</td>
<td>• If Y, RSRV_CAP_NSPIN must have a value and the ROPR curve must be defined</td>
</tr>
<tr>
<td>CERT_NSPIN_RTM (Certified for AS RTM: Non-Spin)</td>
<td>Y/N</td>
<td>An identifier of a resource that is certified to provide Non-Spinning Reserve in the RTM. To be procured in the RTM, a unit must also have a Startup Code Type of FAST.</td>
<td>• If Y, RSRV_CAP_NSPIN must have a value and the ROPR curve must be defined</td>
</tr>
<tr>
<td>REM (Regulation Energy Management)</td>
<td>Y/N</td>
<td>Indicator of a non-generator resource that participates only in the regulation markets.</td>
<td></td>
</tr>
<tr>
<td>MIN_CONT_ENERGY_LIM (Minimum Continuous Energy Limit)</td>
<td>MWh</td>
<td>Minimum stored energy for an LESR. If no real physical energy limit, leave blank.</td>
<td></td>
</tr>
<tr>
<td>MAX_CONT_ENERGY_LIM (Maximum Continuous Energy Limit)</td>
<td>MWh</td>
<td>Maximum stored energy for an LESR. If no real physical energy limit, leave blank.</td>
<td></td>
</tr>
<tr>
<td>RDT Column Name</td>
<td>Unit</td>
<td>Definition</td>
<td>Business Rule</td>
</tr>
<tr>
<td>---------------------------------</td>
<td>---------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>CURT_ENERGY_LIMIT</td>
<td>MWh</td>
<td>The energy limit for curtailing the consumption of energy for NGR. If no limit, leave blank. This is a placeholder for future functionality.</td>
<td></td>
</tr>
<tr>
<td>ENERGY_EFFIC</td>
<td>numeric</td>
<td>The percentage of charging energy that the device can store and later discharge; 0&lt;= n &lt;=1</td>
<td></td>
</tr>
<tr>
<td>EMISSION_RATE</td>
<td>mtCO2/mmBTU</td>
<td>For gas-fired resources, the emission rate (mtCO2/mmBTU) used to determine a resource’s greenhouse gas compliance obligation</td>
<td></td>
</tr>
<tr>
<td>GHG_COMPLIANCE_OBLIG</td>
<td>Y / null</td>
<td>Indicator of a resource that has a greenhouse gas compliance obligation and is eligible to recover greenhouse gas allowance costs</td>
<td></td>
</tr>
<tr>
<td>FORECAST_SELECTION</td>
<td>ISO or SC</td>
<td>Indicator for whether a resource will provide its own forecast (select ‘SC’) or will utilize the ISO’s forecast (select ‘ISO’).</td>
<td>• VER flag must be Y in order for this election to be made&lt;br&gt;• Selecting ‘SC’ requires certification</td>
</tr>
</tbody>
</table>


B.2.2 RESOURCE tab – Reference-only Data

This table contains Generator resource data that is provided in the GRDT for reference only. These values are reflective of a regulatory agreement with the ISO, or are established through a testing, certification, or registration process, or are based on the Full Network Model. Updates cannot be made through the RDT change process, but may be initiated through another business process. The fields are listed in the order they appear in the GRDT.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>PGA_NAME (Participating Generator Agreement Name)</td>
<td></td>
<td>The name of an agreement between the CAISO and a Participating Generator; a pro forma version of which is set forth in Appendix B.2 of the CAISO Tariff.</td>
<td>A revision to this name must match the name on the agreement.</td>
</tr>
<tr>
<td>RES_ID (Resource ID)</td>
<td></td>
<td>The ISO resource identifier used for tracking each resource for market scheduling and outage coordination purposes.</td>
<td></td>
</tr>
<tr>
<td>RES_NAME (Resource Name)</td>
<td></td>
<td>Descriptive Name for the Resource from the PGA or NSPGA Schedule 1, MSS Schedule 14, DR Registration, etc.</td>
<td>A revision to this name must match the facility name on the agreement schedule.</td>
</tr>
<tr>
<td>RES_TYPE (Resource Type)</td>
<td></td>
<td>Descriptive identifier denoting the type of resource: Generating Unit (GEN), Tie Generator (TG), Load.</td>
<td></td>
</tr>
<tr>
<td>AGGREGATE_YN (Aggregate?)</td>
<td>Y/N</td>
<td>A generator resource that consists of more than one individual “child” resources as modeled in the CAISO system.</td>
<td></td>
</tr>
</tbody>
</table>
| ENERGY_TYPE (Energy Type)       |      | Energy Type  
If RES_TYPE = TG:  
• DYN – resource is on a Dynamic Scheduling Agreement  
• FIRM – import resource for scheduling of AS self-provision on ETC/TOR contracts  
If RES_TYPE = GEN, this field is Null |                                                                                               |
<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>FUEL_TYPE</td>
<td></td>
<td>Description of Primary Fuel Type of the Generator; such as, Natural Gas, Oil, Nuclear, etc.</td>
<td>A revision to fuel type must match the agreement schedule.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>GAS – Natural Gas</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>COAL – Coal/Coke</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>DDR – Dispatchable Demand Response</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>OIL – Oil</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>NUCL – Nuclear</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>WAST – Waste to Energy</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>BIOM – Biomass</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>GEOT – Geothermal</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>LESR – Limited Energy Storage Resource</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SOLR – Solar</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>WATR – Water</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>BGAS – Bio Gas (Landfill Sewage Digester etc.)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>HDR – Heat Recovery</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>WIND – Wind</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>OTHR – Other</td>
<td></td>
</tr>
<tr>
<td>GEN_TECH_TYPE</td>
<td></td>
<td>Description of the Prime Mover Technology associated with Generators; such as, Hydro Turbine, Gas Turbine, Combined Cycle, etc</td>
<td>A revision to technology type must match the agreement schedule.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>HYDR – Hydro Turbine</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>PTUR – Hydro Pump-Turbine</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>GTUR – Gas Turbine</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>STUR – Steam Turbine</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CCYC – Combined Cycle</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>RECP – Reciprocating Engine</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>PHOT – Photovoltaic</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>WIND – Wind Turbine</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>PUMP – Pump</td>
<td></td>
</tr>
<tr>
<td>GEN_TYPE</td>
<td>H</td>
<td>Hydro resources</td>
<td></td>
</tr>
<tr>
<td></td>
<td>T</td>
<td>Other resources</td>
<td></td>
</tr>
<tr>
<td>FUEL_REGN_TYPE</td>
<td></td>
<td>The gas region for gas-fired Generators:</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CISO - if Non-Gas</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>PGE1</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>PGE2</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCE1 (if gas usage is under 3 million therms/year)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCE2 (if gas usage is over 3 million therms/year)</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>SDG1 (if gas usage is under 3 million therms/year)</td>
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<tr>
<td></td>
<td></td>
<td>SDG2 (if gas usage is over 3 million therms/year)</td>
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<tr>
<td></td>
<td></td>
<td>KRNP</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>KRNS</td>
<td></td>
</tr>
<tr>
<td>RDT Column Name</td>
<td>Unit</td>
<td>Definition</td>
<td></td>
</tr>
<tr>
<td>-----------------</td>
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<td>------------</td>
<td></td>
</tr>
<tr>
<td>AQM_DIST_TYPE</td>
<td></td>
<td>The Air Quality Management District or Air Pollution Control District in which the resource is located.</td>
<td></td>
</tr>
<tr>
<td>(Air Quality Management District)</td>
<td></td>
<td>AMAD – Amador</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>ANTV - Antelope Valley</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>BUTT – Butte</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CALA – Calaveras</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>COLU – Colusa</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>ELOD – E Dorado</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>FRVR - Feather River</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>GBUN - Great Basin Unified</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>GLEN – Glenn</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>IMPE – Imperial</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>KERN – Kern</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>LAKE – Lake</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>LASS – Lassen</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>MARI – Mariposa</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>MBUN - Monterey Bay Unified</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>MELO – Mendocino</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>MODO – Modoc</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>MOUD - Mojave Desert</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>NOUN – North Coast Unified</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>NSER - Northern Sierra</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>NSON - Northern Sonoma</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>OTHER – Other Region</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>PLAC – Placer</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SACM - Sacramento Metro</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SBRR – Santa Barbara</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SCOA – South Coast</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SDIE - San Diego</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SFBA - San Francisco Bay Area</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SHAS – Shasta</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SISK – Siskiyou</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SJVU - San Joaquin Valley Unified</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>SLUI – San Luis Obispo</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>TEHA – Tehama</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>TUOL – Tuolumne</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>VENT – Ventura</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>YOSO - Yolo/Solano</td>
<td></td>
</tr>
</tbody>
</table>

<p>| CERT_PIRP       | Q, Y, P, I, N, or null | Q = Wind or solar resource in the process of having forecast information evaluated |
| (Certified PIRP)|                  | Y = Wind or solar resources that are flagged as Variable Energy Resources |
|                  |                  | P = PIRP protective measures (without Inter-SC trade) |
|                  |                  | I = PIRP protective measures (with Inter-SC trade) |
|                  |                  | N or Blank = not applicable |</p>
<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
</tr>
</thead>
</table>
| MOO_QUALIFIED (Must Offer Obligation Qualified) | R, N, or Y | • N: Resource is not Must Offer Obligation Qualified  
  • R: Resource is eligible for Must Offer Obligation based on RA Capacity or CPM designation in any given trading hour  
  • Y: Resource is under an RMR or other backstop agreement establishing Must Offer Obligation at all times.  
  • R for Generators that are not use limited, NGR, VER, or must-take  
  • N for Generators if any one of the following is true: USE_LIMIT = Y, NGR = Y, VER = Y, PRIOR_TYPE = MT |
| STARTUP_CD_TYPE (Startup Code Type)    |      | Code used to determine the startup characteristics.  
  • FAST: Generating Units that have a Start Up Time less than ten minutes and are certified to provide non-spin.  
  • Blank: All other resources. |
| PGA_PART (Participating Generator Agreement Flag) | Y/N | An identifier of PGA Resources. |
| COG (Constrained Output Generator Flag) | Y/N | The output of the generation resources is not variable, i.e. \( P_{Max} = P_{Min} \). \( Y \): output is constrained. |
| CERT_BLKSTRT (Certified for Black Start) | Y/N | An identifier of a resource that holds a Black Start agreement and has been certified for Black Start capability |
| CERT_DAM (Certified for Day Ahead Market) | Y/N | An identifier of a resource eligible to participate in the Day Ahead market.  
  • Y for Generators and TG resources  
  • N for Discrete Dispatch RDR and EIM resources (participating and non-participating) |
| CERT_RTM (Certified for Real Time Market) | Y/N | An identifier of a resource eligible to participate in the Real Time market  
  • Y for Generators, TG resources, and participating EIM resources  
  • N for DA-only PDR resources and non-participating EIM resources |
| CERT_RUC (Certified for RUC)           | Y/N | A setting of ‘Y’ allows a resource to participate in RUC market.  
  • Y for Generators and TG resources  
  • N for NGR, RDR, EIM resources (participating and non-participating) |
<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>LMPM (Market Power Mitigation Participation Flag)</td>
<td>Y/N</td>
<td>An identifier of a resource that is subject to the market power mitigation process. Defined per tariff.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Y for Generators, TG resources, and participating EIM resources</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>- N for non-participating EIM resources</td>
<td></td>
</tr>
<tr>
<td>MSS_LD_FLNG_DWN (MSS Load Following Down)</td>
<td>Y/N</td>
<td>Identifier if a resource is load following down - applies to Metered Subsystem only</td>
<td></td>
</tr>
<tr>
<td>MSS_LD_FLNG_UP (MSS Load Following Up)</td>
<td>Y/N</td>
<td>Identifier if a resource is load following up - applies to Metered Subsystem only</td>
<td></td>
</tr>
<tr>
<td>QF (FERC Qualifying Facility Flag)</td>
<td>Y/N</td>
<td>Identifier if a resource is a qualifying cogeneration facility or small qualifying power production facility, as defined in the Code of Federal Regulations, Title 18, Part 292</td>
<td></td>
</tr>
<tr>
<td>USE_LIMIT (Use Limit)</td>
<td>Y/N</td>
<td>Identifier of a resource that is energy use limited, such as limitation of energy or emission control, etc.</td>
<td></td>
</tr>
<tr>
<td>OPER_MAINT_COST (Operating Maintenance Cost Adder)</td>
<td>$/MWh</td>
<td>Variable operations and maintenance (O&amp;M) costs. See Exhibit 4-2 in Section 4 in the body of this BPM for default values of O&amp;M cost adders. For resources that have a negotiated O&amp;M adder, that value will display in this field.</td>
<td>Contact <a href="mailto:ndeb@caiso.com">ndeb@caiso.com</a> to establish a negotiated O&amp;M adder.</td>
</tr>
<tr>
<td>OPER_MAINT_ADDER_TYPE (Operating Maintenance Cost Adder Type)</td>
<td>D/N</td>
<td>This flag identifies whether the Operating Maintenance Cost Adder is the default value (D) or a negotiated (N) value.</td>
<td></td>
</tr>
<tr>
<td>PRIOR_TYPE (Priority Type)</td>
<td></td>
<td>Designator of Regulatory Must-Run, Reliability Must Run, and Must Take resources</td>
<td></td>
</tr>
<tr>
<td>DISP (Dispatchable)</td>
<td>Y/N</td>
<td>Designates a dispatchable resource</td>
<td></td>
</tr>
<tr>
<td>DISCRETE_DISP (Discrete Dispatch)</td>
<td>Y/null</td>
<td>Indicator of a resource that is dispatchable for a specified megawatt quantity. Applies to Reliability Demand Response only.</td>
<td></td>
</tr>
<tr>
<td>RMR (Reliability Must Run)</td>
<td></td>
<td>Designates a resource that has a Reliability Must Run contract</td>
<td></td>
</tr>
<tr>
<td>MAX_RR (Maximum Ramp Rate)</td>
<td></td>
<td>This is a derived field that represents the maximum ramp rate in the operational ramp rate curve.</td>
<td></td>
</tr>
<tr>
<td><strong>RDT Column Name</strong></td>
<td><strong>Unit</strong></td>
<td><strong>Definition</strong></td>
<td></td>
</tr>
<tr>
<td>---------------------</td>
<td>----------</td>
<td>----------------</td>
<td></td>
</tr>
<tr>
<td><strong>PRC_SET_DAM</strong> (Price Setter – DAM)</td>
<td></td>
<td>Can set Market Clearing price in Day Ahead market</td>
<td></td>
</tr>
<tr>
<td><strong>PRC_SET_RTM</strong> (Price Setter – RTM)</td>
<td></td>
<td>Can set Market Clearing price in Real Time market</td>
<td></td>
</tr>
<tr>
<td><strong>MSG_YN</strong> (Multi-Stage Generator Flag)</td>
<td>Y/null</td>
<td>Indicator of a resource that is modeled with multiple configurations under the Multi-Stage Generator (MSG) model.</td>
<td></td>
</tr>
<tr>
<td><strong>STARTUP_RAMP_TIME</strong> (Startup Ramp Time)</td>
<td></td>
<td>Represents the time it takes to physically ramp unit from zero to pmin after the closing of the breaker.</td>
<td></td>
</tr>
<tr>
<td><strong>SUPPLY_CONFIG_YN</strong> (Supplied Configuration Flag)</td>
<td></td>
<td>This is a placeholder for future functionality.</td>
<td></td>
</tr>
<tr>
<td><strong>HR_PRE_DISP</strong> (Hourly Pre-Dispatch)</td>
<td>Y/N/null</td>
<td>This flag indicates a resource that if dispatched, shall be dispatched in the next Trading Hour to operate at a constant level over the entire Trading hour: Y - Hourly only, N - 15-minute market or hourly, Blank - 5-minute market (all Generators)</td>
<td></td>
</tr>
<tr>
<td><strong>NGR</strong> (Non Generator Resource Flag)</td>
<td>Y/N/null</td>
<td>Indicator of a non-generator resource: Y = NGR, N or null = not NGR</td>
<td></td>
</tr>
<tr>
<td><strong>CHP</strong> (Combined Heat and Power Resource Flag)</td>
<td>Y/N/null</td>
<td>Indicator of a combined heat and power resource: Y = CHP, N or null = not CHP</td>
<td></td>
</tr>
<tr>
<td><strong>RMTG_MAX_ON_PEEK</strong> (RMT Max On Peak)</td>
<td>MW</td>
<td>For CHP resources, the portion of capacity that is eligible for Reliability Must-Take scheduling priority during on-peak hours. Must be reestablished annually. For exempt QF resources, this value is set equal to the unit’s pmax. Establish this value or update it by submitting RMT Max value letter to CAISO.</td>
<td></td>
</tr>
<tr>
<td><strong>RMTG_ON_PEAK_EXPIR_DT</strong> (RMT Max On Peak)</td>
<td>DD/MM/YY</td>
<td>Expiration date of the stated RMTG-eligible capacity. For exempt QF resources, no expiration date applies.</td>
<td></td>
</tr>
</tbody>
</table>
| **RMTG_MAX_OFF_PEEK**  
   (RMT Max On Peak) | **MW** | For CHP resources, the portion of capacity that is eligible for Reliability Must-Take scheduling priority during off-peak hours. Must be reestablished annually. For exempt QF resources, this value is set equal to the unit's pmax. | Establish this value or update it by submitting RMT Max value letter to CAISO. |
| **RMTG_OFF_PEAK_EXPIR_DT**  
   (RMT Off Peak Expiration Date) | **DD/MM/YY** | Expiration date of the stated RMTG-eligible capacity For exempt QF resources, no expiration date applies. |
| **ADDEH_AMT**  
   (Minimum Load Major Maintenance Adder) | **$/hour** | A resource-specific adder for major maintenance minimum load cost, if applicable, determined by the CAISO or an independent entity Contact MMAas@caiso.com to establish this value or revise it. |
| **VER_YN**  
   (Variable Energy Resource Flag) | **Y/null** | Indicator of a Variable Energy Resource, defined as “A device for the production of electricity that is characterized by an Energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.” |
| **Energy Imbalance Market Participating Flag**  
   **EIM_PARTICIPATING** | **Y/N/null** | Y = EIM resource that is participating N = EIM resource that is non-participating Blank for non-EIM resources |
| **Balancing Authority Area**  
   **BAA** | | Balancing Authority Area the resource is located in |
### B.2.3 Operational Ramp Rate Curve – RAMPRATE tab

- The Operational Ramp Rate is a staircase curve of up to four segments, defined by five points, which allows a ramp rate to be defined at different operating levels.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type = RAMP</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Segment Number  |      | Point number between the PMin and PMax of the Generating Unit output. | • First point must be 1  
|                 |      |            | • Point numbering must be sequential  
|                 |      |            | • A minimum of 2 points is required  
|                 |      |            | • No more than 5 points (representing 4 segments) allowed |
| Operating Level | MW   | The Generating Unit MW output of point i. The first point (1) of MW output must begin at the Generating Unit's PMin. The last point (n) of MW output must end at the Generating Unit's PMax. | • Value of the first point must equal MIN_GEN  
|                 |      |            | • Value of the last point must equal MAX_GEN |
| Worst Operational Ramp Rate (RAMP_MIN_RATE) | MW/minute | The maximum ramp rate under the worst operating condition of the Generating Unit between point (i) and the point (i+1). A minimum of two points must be provided: the first point (1) at PMin and last point (n) at PMax. | • Must be ≤ RAMP_MAX_RATE for the same point  
|                 |      |            | • RAMP_MIN_RATE of the last 2 points must be the same  
|                 |      |            | • For RDRR, the slowest RAMP_MIN_RATE plus the fastest startup time must be 40 minutes or less. |
| Best Operational Ramp Rate (RAMP_MAX_RATE) | MW/minute | The maximum ramp rate under the worst best operating condition of the Generating Unit between point (i) and the point (i+1). A minimum of two points must be provided: the first point (1) at PMin and last point (n) at PMax. | • Must be 0.1 or greater  
|                 |      |            | • Must be ≥ RAMP_MIN_RATE for the same point  
|                 |      |            | • Cannot be greater than the tested ramp rate (if unit was tested for Ancillary Services)  
|                 |      |            | • RAMP_MAX_RATE of the last 2 points must be the same |
## B.2.4 Heat Rate Curve – HEATRATE tab

This table contains data on the average Heat Rate, Emission Rate or Average Fuel Cost between segments.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type = HEAT</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Number</td>
<td></td>
<td>The point numbers between the PMin and PMax of the Generating Unit output.</td>
<td>• First point must be 1&lt;br&gt;• Point numbering must be sequential&lt;br&gt;• A minimum of 2 points is required&lt;br&gt;• No more than 11 points allowed</td>
</tr>
<tr>
<td>Heat Rate</td>
<td>MW</td>
<td>The Generating Unit output of point 1. The first point (1) of MW output must start at the Generating Unit’s PMIN. The last point (n) of MW output must end at the Generating Unit’s PMAX.</td>
<td>• Value of the first point must equal MIN_GEN&lt;br&gt;• Value of the last point must equal MAX_GEN&lt;br&gt;• A break-point cannot fall within a Forbidden region&lt;br&gt;• A break-point cannot fall within a Regulation range</td>
</tr>
<tr>
<td>Heat Rate</td>
<td>BTU / kWh</td>
<td>For gas-fired units, the average heat rate of the Generating Unit on point (i). If value at point (i) is not available, linear interpolation can be used to approximate the value. Heat rate must be provided at the first point (1) (PMin) and the last point (n) (PMax). If not a gas-fired unit, complete the Average Heat Cost field. For NGR the field is not applicable and must be 0. For EIM, this field is used for non-gas resources to compute the GHG bid cap. Non-gas resources complete the average heat cost field as well.</td>
<td>Heat Rate must be provided if FUEL_TYPE = GAS&lt;br&gt;Heat input must be monotonically increasing: [(HEAT_RATE * HEAT_MW_OUTPUT/ 1000) in segment (i+1) must be greater than (HEAT_RATE * HEAT_MW_OUTPUT/ 1000) in segment (i)]</td>
</tr>
<tr>
<td>Emission Rate</td>
<td>lbs of NOx/MWh</td>
<td>This is informational only - Market software does not reference this data element. The emission rate of the Generating Unit on point (i). If value at point (i) is not available, linear interpolation can be used to approximate the value. Emission rate must be provided at the first point (1) (PMin) and the last point (n) (PMax)</td>
<td></td>
</tr>
<tr>
<td>Average Cost</td>
<td>$/MWh</td>
<td>Use this value for fuel costs of non-gas fired units instead of Heat Rate and natural gas</td>
<td>These values are used to calculate the incremental fuel cost</td>
</tr>
</tbody>
</table>
### RDT Column Name | Unit | Definition | Business Rule
--- | --- | --- | ---
Resource ID | | | |
HEAT_AVG_COST | | price indices. The average cost of the Generating Unit on point (i) in $/MWh. If value at point (i) is not available, linear interpolation can be used to approximate the value. Average cost must be provided at the first point (1) (PMin) and the last point (n) (Pmax). costs used in determining a resource's default energy bid under the Variable Cost Option for non-gas resources as described in 39.7.1.1. Fuel cost values do not include any greenhouse gas allowance costs, variable operating and maintenance costs or other administrative charges. Average fuel cost values may be subject to verification and require supporting documentation upon request by the ISO.

#### B.2.5 Start-Up Curve – STARTUP tab

Start-up Time and Start-up Cost are staircase curves reflecting the conditions for Start-up, whether hot, warm, or cold. Both are expressed as a function of Cooling Time.

For RDRR, the slowest Operational Ramp Rate and fastest Start-Up Time must be coordinated so that the resource starts up and ramps from zero to full capacity in no more than 40 minutes.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type = STRT</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Segment Number | | The segment numbers corresponding to cooling time of the unit. One segment is required. Up to 3 segments are allowed, representing a hot, warm, and cold start. | • First segment must be 1  
• Segment numbers must be sequential |
| Registered Cooling Time | minutes | The amount of time the Generating Unit must be off (in minutes) within sequence (i). The first downtime must be zero to account for a unit which has just shut down. | • Value in first segment must be 0  
• Value must increase with each sequential segment (if more than one segment exists) |
| **Start-Up Time** | **minutes** | Start-Up Time is the time (in minutes) it takes a resource to achieve PMin from an off-line position given the corresponding Down Time (Registered Cooling Time). The startup time of the Generating Unit (in minutes) from the cooling time (i) to cooling time (i + 1). The last segment represents the startup time (in minutes) from cooling time (n) to infinity. This value includes notification time. For NGR the field is not applicable and must be 0. | - Value must increase with each sequential segment  
- Value in first segment must <= MIN_OFF time  
- For RDRR, the slowest RAMP_MIN_RATE plus the fastest startup time must be 40 minutes or less. |
| **Start-Up Cost** | **$/start** | The startup cost of non-natural gas fired Generating Units (in dollars) from the cooling time (i) to cooling time (i + 1). The last segment represents the startup cost (in dollars) from cooling time (n) to infinity. For NGR the field is not applicable and must be 0. | - Value must increase with each sequential segment  
- May not exceed 150% of unit's projected proxy startup cost if SU_COST_BASIS_TYPE = REGC  
- A Startup Cost with more than 2 decimal places submitted in an RDT will be rounded to 2 decimal places |
| **Start-Up Aux** | **MWh** | The electrical power used by a Generating Unit during startup. The Generating Unit's startup auxiliary power (in MWh) from the down time (i) to down time (i + 1). The last sequence is the startup auxiliary power (in MWh) from current sequence to infinite. For NGR the field is not applicable and must be 0. | - Cannot be null if Fuel_type is GAS |
| **Start-Up Fuel** | **mmBTU** | The fuel use (in mBTU per start) expected for the startup of a Generating Unit that has been off-line for a substantial period of time. The startup fuel of the Generating Unit (in mBTU) from the down time (i) to down time (i + 1). The last sequence is the startup fuel (in mBTU) from current sequence to infinite. For NGR the field is not applicable and must be 0. | - Value must increase with each sequential segment |
| **Start-Up MMA** | **$/start** | A resource-specific major maintenance adder value per start-up, if applicable, agreed to by the CAISO or an Independent Entity. This field is READ-ONLY. | Contact MMA@caiso.com to establish this value or revise it. |
## B.2.6 Forbidden Range Curve - FORBIDDEN OPR REGION Tab

A Forbidden Region is an output range in which a Generator cannot safely operate.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type = FBRD</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Segment Number  |      | This number represents a given forbidden region. Segment number 1 should be the forbidden region at the lowest level in the operating range. Segment numbers should correspond to sequential regions along the operating range, ending with segment (n) at the highest operating level. | • First segment must be 1  
• Segment numbers must be sequential  
• No more than 4 segments (representing 4 forbidden regions are allowed) |
| Lower MW of Forbidden Region | MW | The lower MW output of the forbidden range of the current segment. The forbidden region should be inside of segment (i); meaning a forbidden region cannot cross two segments and the segment cannot be overlapped. Note: forbidden regions cannot include nor overlap regulation ranges or heat segments. | • Must be \( \geq \) MIN_GEN + 0.1 |
| Upper MW of Forbidden Region | MW | The upper MW output of the forbidden region of the current segment. The forbidden region should be inside of segment (i); meaning a forbidden region cannot cross two segments and the segment cannot be overlapped. Note: Forbidden regions cannot include nor overlap regulation ranges or heat segments. | • Must be \( \leq \) MAX_GEN - 0.1 |
| Forbidden Region Crossing Time | minutes | The time in minutes for a generator to ramp through a Forbidden Region. | • If FBRD segment exists, Forbidden Region Crossing Time must be \( \geq 1 \) |
B.2.7 Regulation Range Curve – REGULATION tab

This table describes the regulation range for a resource that is certified for Regulation Up or Regulation Down.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type = REG</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Number</td>
<td></td>
<td>Number of the regulation range. Up to two ranges are allowed where segment number 1 describes the lower range and segment number 2 describes the upper range.</td>
<td>Up to 2 segments allowed.</td>
</tr>
<tr>
<td>Lower MW for Regulation</td>
<td>MW</td>
<td>The Lower MW output of the current Regulation Range segment.</td>
<td>Must be &gt;= MIN_GEN</td>
</tr>
<tr>
<td>Higher MW for Regulation</td>
<td>MW</td>
<td>The Higher MW output of the current Regulation Range segment.</td>
<td>Must be &gt; Lower MW for Regulation and &lt;= MAX_GEN</td>
</tr>
</tbody>
</table>

B.2.8 Regulation Ramp Rate Curve - REG RAMP tab

This table describes the regulation ramp rate for a resource that is certified for Regulation Up or Regulation Down.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type = RREG</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Number</td>
<td></td>
<td>One regulation ramp rate is allowed per resource and applies to all defined regulation ranges for the resource.</td>
<td>1 segment allowed</td>
</tr>
<tr>
<td>Worst Regulation Ramp Rate</td>
<td>MW/minute</td>
<td>The maximum Regulation Ramp Rate under the worst condition.</td>
<td>Must be &gt; 0</td>
</tr>
<tr>
<td>Best Regulation Ramp Rate</td>
<td>MW/minute</td>
<td>The maximum Regulation Ramp Rate under the best condition.</td>
<td>Must be &lt;= Best Operating Ramp Rate (RAMP curve)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Must be &lt;= the tested Regulation ramp rate</td>
</tr>
</tbody>
</table>
B.2.9 **Operating Reserve Ramp Rate Curve - OP RES RAMP tab**

This table contains the data on the maximum ramp rate of the Generator certified for spin and non-spin between worst and best operating conditions between segments.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type = ROPR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Number</td>
<td></td>
<td>One operating reserve ramp rate covers procurement of both Spinning and Non-Spinning reserve.</td>
<td>• 1 segment allowed</td>
</tr>
<tr>
<td>Worst Operating Res Ramp Rate</td>
<td>MW/minute</td>
<td>The maximum Operating Reserve Ramp Rate under the worst condition.</td>
<td>• Must be &gt; 0</td>
</tr>
<tr>
<td>Best Operating Res Ramp Rate</td>
<td>MW/minute</td>
<td>The maximum Operating Reserve Ramp Rate under the best condition.</td>
<td>• Must be &lt;= Best Operating Ramp Rate (RAMP curve)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Must be &lt;= the tested Spin or Non-Spin ramp rate</td>
</tr>
</tbody>
</table>

B.2.10 **Multi Stage Generating Resource – MSG_CONFIG tab**

This table describes the data fields that apply to configurations of Multi Stage Generating Resources.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td>The ISO resource identifier used for tracking each resource for market scheduling and outage coordination purposes.</td>
<td></td>
</tr>
<tr>
<td>Configuration ID</td>
<td>Identifier of the MSG configuration.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Configuration Name</td>
<td>MSG configuration name</td>
<td></td>
<td></td>
</tr>
<tr>
<td>RDT Column Name</td>
<td>Unit</td>
<td>Definition</td>
<td>Business Rule</td>
</tr>
<tr>
<td>-------------------------------------</td>
<td>------</td>
<td>-----------------------------------------------------------------------------</td>
<td>--------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Maximum Generation Capacity</td>
<td>MW</td>
<td>The maximum normal capability at the configuration level.</td>
<td>• Config’s MAX_GEN &lt;= resource’s MAX_GEN</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Config’s MAX_GEN &gt;= config’s MIN_GEN</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Must equal the maximum output level (last segment) in the config’s HEAT curve</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Must equal the maximum output level (last segment) in the config’s RAMP curve</td>
</tr>
<tr>
<td>Minimum Generation Capacity</td>
<td>MW</td>
<td>For a configuration, the minimum sustained operating level (Pmin) at which it can operate at a continuous level.</td>
<td>• Config’s MIN_GEN &gt;= resource’s MIN_GEN</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Config’s MIN_GEN &lt;= config’s MAX_GEN</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Must equal the minimum output level (segment 1) in the config’s HEAT curve</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Must equal the minimum output level (segment 1) in the config’s RAMP curve</td>
</tr>
<tr>
<td>Minimum On Time</td>
<td>minutes</td>
<td>The minimum amount of time that the MSG resource will operate in this configuration</td>
<td></td>
</tr>
<tr>
<td>Minimum Off Time</td>
<td>minutes</td>
<td>The time that an MSG resource is operating in a different configuration or transitioning, in addition to the time the resource is off line, is the “Off” time for a given configuration.</td>
<td>• Cannot be null for a start-able configuration</td>
</tr>
<tr>
<td>Minimum Load Cost</td>
<td>$ / hour</td>
<td>The costs a configuration incurs operating at minimum load. The value is required for a resource with the ML Cost Basis of Registered Cost (fixed value) only.</td>
<td>• Cannot be null if ML Cost Basis Type of REGC (Registered) is selected</td>
</tr>
<tr>
<td>Reserve Capacity: Spin</td>
<td>MW</td>
<td>At the configuration level, the portion of unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and that is capable of running for at least two hours.</td>
<td>• Must have a value if CERT_SPIN is Y.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Cannot be greater than the tested Spin capacity.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Must be less than or equal to MAX_GEN - MIN_GEN of the configuration</td>
</tr>
<tr>
<td>RDT Column Name</td>
<td>Unit</td>
<td>Definition</td>
<td>Business Rule</td>
</tr>
<tr>
<td>---------------------------------</td>
<td>------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------------------------</td>
</tr>
</tbody>
</table>
| Reserve Capacity: Non-Spin      | MW   | At the configuration level, the portion of off-line generating capacity that is capable of being synchronized and Ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted.) | • Must have a value if CERT_NSPIN_DAM or CERT_NSPIN_RTM flags are set to Y.  
• Cannot be greater than the tested Non-spin capacity.  
• Must be less than or equal to MAX_GEN of the configuration |
| Configuration Startup           | Y / N| An identifier of a configuration that is able to start-up directly from off-line                                                                                                                             | • Must be 'Y' for at least one configuration                                                     |
| Configuration Shutdown          | Y / N| An identifier of a configuration that can shutdow n without going through another configuration.                                                                                                            | • Must be 'Y' for at least one configuration                                                     |
| Startup Ramp Time               | minutes | Represents the time it takes to physically ramp from zero to pmin after the closing of the breaker.                                                                                                       | • Must be <= minimum startup time for this configuration in the CONFIG_STRT curve               |
| Startup Code Type               | FAST or null | Code used to determine the startup characteristics. FAST: Configuration that has a Start Up Time of ten minutes or less and can provide non-spin. Blank: All other configurations. | • Set to 'FAST' if Startup Time in segment 1 in Startup curve is 10 minutes or less.  
• Leave null for all others. |
| Certified for AS: Regulation Dow n | Y / N | An identifier of a configuration that is certified to provide Regulation Dow n Reserve.                                                                                                                                 | • Set to Y if configuration is certified for Regulation Dow n  
• Must be Y for at least one configuration if resource is certified for regulation dow n |
| Certified for AS: Regulation Up  | Y / N | An identifier of a configuration that is certified to provide Regulation Up Reserve.                                                                                                                                 | • Set to Y if configuration is certified for Regulation Up  
• Must be Y for at least one configuration if resource is certified for regulation up |
| Certified for AS: Spin           | Y / N | An identifier of a configuration that is certified to provide Spinning Reserve.                                                                                                                                 | • Set to Y if configuration is certified for Spin  
• Must be Y for at least one configuration if resource is certified for spin                         |
<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Certified for AS: Non-Spin</td>
<td>Y / N</td>
<td>An identifier of a configuration that is certified to provide Non-Spinning</td>
<td>• Set to Y if configuration is certified for Non-Spin&lt;br&gt;• Must be Y for at least one configuration if resource is certified for non-spin</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Reserve in the DAM.</td>
<td></td>
</tr>
<tr>
<td>Minimum Load Major Maintenance</td>
<td>$/hour</td>
<td>A configuration-specific adder for minimum load cost, if applicable. This</td>
<td>Contact <a href="mailto:MMAs@caiso.com">MMAs@caiso.com</a> to establish this value or revise it.</td>
</tr>
<tr>
<td>Adder</td>
<td></td>
<td>field is READ-ONLY.</td>
<td></td>
</tr>
<tr>
<td>RA Range Min</td>
<td>MW</td>
<td>For each configuration, indicates the minimum level of Resource Adequacy</td>
<td>• The RA range for the MSG resource must be contiguous (no gaps, no overlaps) and cover the range from MIN_GEN of the lowest configuration to MAX_GEN of the highest configuration&lt;br&gt;• RA Range Min of subsequent configurations must be equal to the RA Range Max of the previous configuration plus 0.01.&lt;br&gt;• RA Range Min for a configuration can be less than the MIN_GEN of that configuration only if it does not fall within another MSG configuration’s MIN_GEN and MAX_GEN</td>
</tr>
<tr>
<td></td>
<td></td>
<td>capacity that the configuration will provide.</td>
<td></td>
</tr>
<tr>
<td>RA Range Max</td>
<td>MW</td>
<td>For each configuration, indicates the maximum level of Resource Adequacy</td>
<td>• Must be equal to or less than the MAX_GEN for that configuration</td>
</tr>
<tr>
<td></td>
<td></td>
<td>capacity that the configuration will provide.</td>
<td></td>
</tr>
</tbody>
</table>
B.2.11 MSG Transition Matrix – TRANSITION tab

The transition matrix defines feasible transitions for configurations of a Multi Stage Generator Resource. A transition from a particular configuration to another must be defined in this tab of the RDT for it to be allowed to perform in the market.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Configuration ID - From</td>
<td></td>
<td>This configuration ID is the starting point for a transition between two configurations. Each transition represents one direction.</td>
<td></td>
</tr>
<tr>
<td>Configuration ID - To</td>
<td></td>
<td>This configuration ID is the ending point for a transition between two configurations. Each transition represents one direction.</td>
<td></td>
</tr>
</tbody>
</table>
| Transition Cost            | $ / transition | The cost of moving from 'Configuration ID-From' to 'Configuration ID-To'. Provide a cost here if the resource has indicated Registered Cost basis for Startup Cost. If the resource is Proxy Cost basis, the Transition Cost will be calculated in the bid as the difference in the startup cost between the 'To' and 'From' configurations when a resource is increasing from a lower configuration to a higher configuration. | ● May not exceed 150% of the difference in startup cost of the 'Configuration ID-To' minus the startup cost of the 'Configuration ID-From' if SU_COST_BASIS_TYPE = REGC  
● Non-zero cost is not allowed for downward transition (from higher to lower configuration) |
| Transition Ramp Time       | minutes      | The time in minutes it takes to move from 'Configuration ID-From' to 'Configuration ID-To'.                                                                                                                  | ● Must be <= Notification time                                                                     |
| Notification Time          | minutes      | The time in minutes a configuration requires before deployment. Notification time includes transition time. For example, a configuration with a notification time of 60 minutes and a transition time of 10 minutes is expected to begin transitioning after 50 minutes. | ● Must be <= 240 minutes (the maximum time RTPD looks ahead)  
● Must be >= Transition time                                                                 |
| Maximum Daily Transitions  |              | The maximum number of times this transition can be performed each day                                                                                                                                 |                                                                                                   |
| Transition Midpoint MW     |              | Transition profile breakpoint allows for modeling a transition with nonlinear ramping profile                                                                                                           |                                                                                                   |
| Transition Midpoint Time   |              | Transition midpoint time allows for modeling a transition with nonlinear ramping profile                                                                                                                |                                                                                                   |
### B.2.12 MSG Configuration Ramp Rate Curve – CONFIG_RAMP tab

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Configuration ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Segment Number        |            | Point numbers between the PMin and PMax of the configuration. The point numbering starts at 1. Up to two ramp rates are allowed at the configuration (3 points) | • First point must be 1  
• No more than 2 ramp rates allowed (3 "points") |
| Operating Level       | MW         | The configuration MW output of point. The first point of MW output must begin at the configuration's PMin. The last point of MW output must end at the configuration's PMax. | • Value of the first point must equal MIN_GEN of the configuration  
• Value of the last point must equal MAX_GEN of the configuration |
| Worst Operational Ramp Rate | MW / minute | The maximum ramp rate under the worst operating condition of the configuration. | • Must be > 0  
• Cannot be greater than RAMP_MAX_RATE for the same point  
• RAMP_MIN_RATE of the last 2 points must be equal |
| Best Operational Ramp Rate | MW / minute | The maximum ramp rate under the best operating condition of the configuration. | • Must be >= 0.1  
• Cannot be greater than the tested ramp rate (if unit was tested for Ancillary Services)  
• RAMP_MAX_RATE of the last 2 points must be equal |
### B.2.13 MSG Configuration Heat Rate Curve – CONFIG_HEAT tab

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Configuration ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Number</td>
<td></td>
<td>The point numbers between the PMin and PMax of the configuration MW output.</td>
<td>• First point must be 1</td>
</tr>
<tr>
<td></td>
<td></td>
<td>The point starts at 1. Up to 11 points are allowed.</td>
<td>• Point numbering must be sequential</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• No more than 11 points allowed</td>
</tr>
<tr>
<td>Heat Rate</td>
<td>MW</td>
<td>The configuration MW output at point 1. The first point (1) of MW output</td>
<td>• Value of the first point must equal MIN_GEN of the configuration</td>
</tr>
<tr>
<td></td>
<td></td>
<td>must start at the configuration's PMIN. The last point (n) of MW output</td>
<td>• Value of the last point must equal MAX_GEN of the configuration</td>
</tr>
<tr>
<td></td>
<td></td>
<td>must end at the configuration's PMAX.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heat Rate</td>
<td>BTU/kWh</td>
<td>For gas-fired units only, the average heat rate of the configuration on point</td>
<td>Heat Rate must be provided if resource's Fuel Type = Gas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(i). If value at point (i) is not available, linear interpolation can be</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>used to approximate the value. Heat rate must be provided at the first</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>point (1) (Pmin) and the last point (n) (PMAX).</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>If not a gas-fired unit, leave blank and instead complete the Average Heat</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Cost field.</td>
<td></td>
</tr>
<tr>
<td>Heat Emission Rate</td>
<td>lbs</td>
<td>lbs of NOx/MWh</td>
<td>This is informational only - Market software does not reference this data element.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>The emission rate of the configuration on point (i). If value at point</td>
<td>The emission rate must be provided at the first point (1) (PMin) and the last point (n) (PMAX).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(i) is not available, linear interpolation can be used to approximate the</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>value. Emission rate must be provided at the first point (1) (PMin) and the</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>last point (n) (PMAX).</td>
<td></td>
</tr>
<tr>
<td>Average Cost</td>
<td>$/MWh</td>
<td>Use this value for non-gas fired units to represent fuel costs instead of</td>
<td>• Average Cost must be provided if resource’s Fuel Type is not Gas.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Heat Rate and natural gas price index. The average cost of the configuration</td>
<td>• These values are used to calculate the incremental fuel costs used in determining a configuration’s default energy bid under the Variable Cost Option for non-gas resources as described in 39.7.1.1. Fuel cost values do not include any greenhouse gas allowance costs, variable operating and maintenance costs or other administrative costs.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>on point (i) in $. If value at point (i) is not available, linear</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>interpolation can be used to approximate the value. Average cost must be</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>provided at the first point (1) (PMin) and the last point (n) (PMAX).</td>
<td></td>
</tr>
</tbody>
</table>
B.2.14  MSG Configuration Start-Up Curve – CONFIG_STRT tab

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Configuration ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type = STRT</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| Segment Number           |          | The segment numbers corresponding to cooling time of the configuration. The  | • First segment must be 1  
|                          |          | segment starts at 1. Up to 3 segments are allowed (hot, warm and cold).       | • Segment numbers must be sequential  
|                          |          |                                                                             | • 3 segments allowed                                                                            |
| Registered Cooling Time  | minutes  | The amount of time the configuration must be off (in minutes) within       | • Value in first segment must be 0                                                                                |
|                          |          | sequence (i). The first down time must be zero to account for a configuration  |                                                                                                  |
|                          |          | has just shut down.                                                        |                                                                                                  |
| Startup Time             | minutes  | Startup Time is the time (in minutes) it takes a configuration to achieve PM | • Value must increase with each sequential segment                                                     |
|                          |          | min from an off-line position given the corresponding Down Time (Registered |                                                                                                  |
|                          |          | Cooling Time). The startup time of the configuration (in minutes) from cooling |                                                                                                  |
|                          |          | time (i) to cooling time (i + 1). The last segment represents the startup time |                                                                                                  |
|                          |          | from cooling time (n) to infinity.                                          |                                                                                                  |
| Startup Cost             | $ / start| The startup cost of a configuration (in dollars) from the cooling time (i)  | • Value must increase with each sequential segment
|                          |          | to cooling time (i + 1). The last segment represents the startup cost (in   | • May not exceed 150% of configuration's projected proxy startup cost if SU_COST_BASIS_TYPE = REGC |
|                          |          | dollars) from cooling time (n) to infinity.                                 | • A Startup Cost with more than 2 decimal places submitted in an RDT will be rounded to 2 decimal   |
|                          |          | Startup cost provided for a start-able GAS configuration under Proxy Cost, or | places                                                                          |
|                          |          | for any “indirect” configuration, will be ignored by the software.           |                                                                                                  |
### B.2.15  MSG Configuration Regulation Range – CONFIG_REG tab

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start-Up Aux</td>
<td>MWh</td>
<td>The electrical power used by a configuration during startup, or for an &quot;indirect&quot; configuration to achieve pmin. The configuration's startup auxiliary power (in MWh) from the down time (i) to down time (i + 1). The last sequence is the startup auxiliary power (in MWh) from current sequence to infinity. This number provided for an &quot;indirect&quot; configuration will be used in the calculation for Transition Cost.</td>
<td></td>
</tr>
<tr>
<td>Start-Up Fuel</td>
<td>mmBTU</td>
<td>The fuel use (in mBTU per start) expected for the startup of a natural gas fired configuration that has been off-line, or for an &quot;indirect&quot; configuration to achieve pmin. The startup fuel of the configuration (in mBTU) from the down time (i) to down time (i + 1). The last sequence is the startup fuel (in mBTU) from current sequence to infinity. This number provided for an indirect configuration will be used in the calculation for Transition Cost.</td>
<td></td>
</tr>
<tr>
<td>Start-Up MMA</td>
<td>$ / start</td>
<td>A resource configuration-specific major maintenance adder value per start-up, if applicable, agreed to by the CAISO or an Independent Entity. This field is READ-ONLY</td>
<td>Contact <a href="mailto:MMAs@caiso.com">MMAs@caiso.com</a> to establish this value or revise it.</td>
</tr>
</tbody>
</table>

### B.2.16  MSG Configuration Regulation Ramp Rate – CONFIG_RREG tab

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Configuration ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Type = REG</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Segment Number</td>
<td></td>
<td>Number of the regulation range. One regulation range is allowed for a configuration.</td>
<td>• 1 Segment allowed</td>
</tr>
<tr>
<td>Lower MW for Regulation</td>
<td>MW</td>
<td>Lower level of the Regulation Range.</td>
<td>• Must be &gt;= MIN_GEN of configuration</td>
</tr>
<tr>
<td>Higher MW for Regulation</td>
<td>MW</td>
<td>Higher level of the Regulation Range.</td>
<td>• Must be &lt;= MAX_GEN of configuration</td>
</tr>
</tbody>
</table>

---

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### RDT Column Name | Unit | Definition | Business Rule
--- | --- | --- | ---
Configuration ID | | | |
Segment Type = RREG

<table>
<thead>
<tr>
<th>Segment Number</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Worst Regulation Ramp Rate</td>
<td>MW / minute</td>
<td>The maximum Regulation Ramp Rate for the segment under the worst condition.</td>
<td>• 1 Segment allowed</td>
</tr>
</tbody>
</table>
| Best Regulation Ramp Rate | MW / minute | The maximum Regulation Ramp Rate for the segment under the best condition. | • Must be > 0.1  
• Must be <= Best Operating Ramp Rate (RAMP curve) of the configuration |

#### B.2.17 MSG Configuration Operating Reserve Ramp Rate – CONFIG_ROPR tab

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource ID</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Configuration ID</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Segment Type = ROPR

<table>
<thead>
<tr>
<th>Segment Number</th>
<th>Unit</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Worst Operating Res Ramp Rate</td>
<td>MW / minute</td>
<td>The maximum Operating Reserve Ramp Rate under the worst condition</td>
<td>• Must be &gt; 0</td>
</tr>
</tbody>
</table>
| Best Operating Res Ramp Rate | MW / minute | The maximum Operating Reserve Ramp Rate under the best condition. | • Must be > 0.1  
• Must be <= Best Operating Ramp Rate (RAMP curve) |
B.2.18 Child Resources of Aggregate Resource – Non Modifiable

For aggregate resources, this tab of the RDT displays the child resources that are included in the aggregate. The information is read-only and not updateable through the RDT update process.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aggregate Resource ID</td>
<td>The ISO resource identifier used for tracking each resource for market scheduling and outage coordination purposes.</td>
<td></td>
</tr>
<tr>
<td>Aggregate Resource Name</td>
<td>Descriptive name for the resource.</td>
<td></td>
</tr>
<tr>
<td>Child Resource ID</td>
<td>The ISO resource identifier used for tracking each resource.</td>
<td></td>
</tr>
<tr>
<td>Child Resource Name</td>
<td>Descriptive name for the resource.</td>
<td></td>
</tr>
<tr>
<td>Maximum Child Generation Capacity</td>
<td>The maximum generating capability of the child unit.</td>
<td></td>
</tr>
</tbody>
</table>

B.3 Intertie Resource Data Template

B.3.1 Intertie Resource tab – Modifiable Data

Bids at the Interties for system resources will be assigned a transaction identifier when the bid is submitted. Transaction IDs are not registered in the Master File, thus no new intertie resource IDs will be created unless they are for one of the following exceptions:

- Resource Adequacy
- Existing transmission contracts
- IBAA agreements for transmission loss adjustment
- Emergency assistance
- Marginal loss cost adjustment
- Stranded Load

This table shows the data elements where changes to the data can be initiated by the Market Participants through the RDT update process.
<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>MIN_HR_BLK_LIM  (Minimum Hourly Block Limit (1-24 hours))</td>
<td>Represents the maximum number of consecutive Trading Hours that an Intertie resource can be bid in, if a Minimum Hourly Block is specified in the Bid.</td>
<td>Must be a whole number from 1 to 24.</td>
</tr>
<tr>
<td>GMC_RANK_LMPM   (Price Taker Option)</td>
<td>A method of calculating Generated Bids based on a price taker value of zero plus an estimate of the Grid Management Charge.</td>
<td>Rank 1 or null Only one of the three ranking fields (GMC_RANK_LMPM, NEGO_RANK_LMPM, and PRC_RANK_LMPM) can be ranked as 1.</td>
</tr>
<tr>
<td>NEGO_RANK_LMPM  (Negotiated Rate Option)</td>
<td>A method of calculating Generated Bids based on a negotiation with the CAISO or the Independent Entity.</td>
<td>Rank 1, 2 or null Only one of the three ranking fields (GMC_RANK_LMPM, NEGO_RANK_LMPM, and PRC_RANK_LMPM) can be ranked as 1.</td>
</tr>
<tr>
<td>PRC_RANK_LMPM   (LMP Option)</td>
<td>A method of calculating Generated Bids based on Locational Marginal Prices.</td>
<td>Rank 1 or null Only one of the three ranking fields (GMC_RANK_LMPM, NEGO_RANK_LMPM, and PRC_RANK_LMPM) can be ranked as 1.</td>
</tr>
<tr>
<td>HR_PRE_DISP (Hourly Pre_Dispatch)</td>
<td>This flag indicates a resource that if dispatched, shall be dispatched in the next Trading Hour to operate at a constant level over the entire Trading hour. Y - Hourly only N - 15-minute market or hourly</td>
<td></td>
</tr>
</tbody>
</table>

**Explanation of the Generated Bids fields**

The Scheduling Coordinator for each non-Resource Specific System Resource that has a Resource Adequacy obligation shall select the methodology for calculating the Generated Bids using these fields:

- NEGO_RANK_LMPM = Negotiated
- PRC_RANK_LMPM = Locational Marginal Price (LMP)
- GMC_RANK_LMPM = Price Taker plus the Grid Management Charge (Price Taker)

There are five possible scenarios for the ranking of Generated Bids fields in the Intertie Resource Data Template (IRDT).
### Scenarios

<table>
<thead>
<tr>
<th>Scenarios</th>
<th>NEGO_RANK_LMPM</th>
<th>PRC_RANK_LMPM</th>
<th>GMC_RANK_LMPM</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td></td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td></td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>5</td>
<td>2</td>
<td></td>
<td>1</td>
</tr>
</tbody>
</table>

- Scenario 1, if there is nothing selected (all fields are blank or null) the default will be GMC_RANK_LMPM.
- Scenario 2, Selected GMC_RANK_LMPM. There is no second or third option.
- Scenario 3, Selected NEGO_RANK_LMPM. There is no second or third option.
- Scenario 4, Selected PRC_RANK_LMPM. A second selection is required; in this scenario it is GMC_RANK_LMPM.
- Scenario 5, Selected PRC_RANK_LMPM. A second selection is required; in this scenario it is NEGO_RANK_LMPM.

See Tariff section 40.6.8.1 that discusses the different Generated Bid options: “Price Taker”, “LMP-Based”, “Negotiated Price”.

### B.3.2 Intertie Resource Reference Only

This table contains Intertie resource data that is provided in the IRDT for reference only. The fields are listed in the order they appear in the IRDT.

<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>RES_ID</td>
<td>The ISO resource identifier used for tracking each resource for market scheduling.</td>
<td>Once created, the resource ID cannot be changed. The resource must end-dated and a new resource ID created.</td>
</tr>
</tbody>
</table>
| ENERGY_TYPE     | An identifier of the type of Energy from an Intertie resource as it pertains to Ancillary Service Requirements, Dynamic Interchange or Wheeling. | FIRM – Firm Import/Export  
NFRM – Non-Firm Import/Export  
WHL – Wheeling  
UCTG – Unit Contingent |
<table>
<thead>
<tr>
<th>RDT Column Name</th>
<th>Definition</th>
<th>Business Rule</th>
</tr>
</thead>
<tbody>
<tr>
<td>CERT_RUC (Certified for RUC)</td>
<td>Identifier of a resource that is eligible to participate in RUC.</td>
<td>This flag is set to Y if a resource has Resource Adequacy capacity for a given trade date.</td>
</tr>
<tr>
<td>MOO (MOO Resource)</td>
<td>This field is no longer used and will be removed in next version of IRDT</td>
<td></td>
</tr>
</tbody>
</table>
| MOO_QUALIFIED (Must Offer Obligation Qualified) | N - Resource is not Must Offer  
R - Resource is eligible for Must Offer based on RA Capacity or RCST designation in any given trading hour | • N for all export resources  
• R for all import resources. |
| WHEEL_REFERENCE_NUMBER (Wheel Reference ID) | Represents the wheeling counter resource that can be used in the Wheeling Bid Component of an Intertie resource bid. This ID is created in Master File and corresponds to the import wheel resource ID |                                                                               |
| STRANDED_LOAD                   | Identifies whether or not the resource is available for stranded load.     |                                                                               |
| MLCA (Marginal Loss Cost Adjustment) | Identifier of a resource eligible to receive the marginal loss cost adjustment of LMPs. |                                                                               |

### B.4 Grouping Constraints for Pump Storage (PS) Resource

The reference section of the Schedule 1 of the Participating Generator Agreement (PGA) should include a description of any group of two or more resources that are subject to constraints for minimum lag time between successive startups and/or shutdowns due to physical limitations. The description of these limitations may be generic if the lag time values are subject to change.

To add or update the minimum lag times for group constraints, Scheduling Coordinators should complete the Group Constraints Request Form and submit to RDT@caiso.com. Group Constraints requests will be processed within the 5 to 11 business day Master File change process.

### B.5 Configuration Grouping for Multi Stage Generator (MSG) Resource

Minimum Up Time (MUT) and Minimum Down Time (MDT) constraints are enforced at the MSG resource (plant) level and at individual MSG configuration levels. MUT and MDT may also be specified for a group of MSG configurations.

For a group of configurations, MUT represents the total time that the MSG resource must stay within the group. For example, suppose a MSG resource has 6 configurations, with configurations 5 and 6 part of a group with a MUT of 6 hours. Once dispatched into either
configurations 5 or 6, the resource may transit between configuration 5 and 6, but cannot move to a different configuration until the 6-hour MUT has passed. Transition time between MSG configurations within the group is considered as "ON" Time of the group.

Submit a completed MSG Configuration Group Registration form to establish or update the MUT and MDT for an MSG configuration group to RDT@caiso.com.
Attachment C

GAS PRICE INDEX CALCULATION RULES
C   Gas Price Index Calculation Rules

C.1 Background

The daily Gas Price Index (GPI) is the index that is used in the calculation of the Default Energy Bids, as well as the generated bids including Startup Costs, and Minimum Load Costs subject to the proxy cost option. The GPI has a number of key components, including principally the gas price indices themselves and the intra-state gas transport costs. Gas Price Indices consist of a single price ($/mmBTU) for each GPI Region, of which there is at least one for each of the main LSEs. Each Resource is associated with the GPI Region in which it resides, or to which it is geographically closest. The GPI calculated for resources assigned to a BAA regional fuel region (e.g., CISO) will be the minimum of all GPI index values for GPI Regions within the BAA. Monthly futures gas prices are used in the calculation of Demand Response net benefits test (DR NBT) threshold prices and projected proxy costs. The monthly price is calculated similar to the daily price, but using an average of several days’ futures prices instead of a single day-ahead price.

C.2 Gas Transport Cost

The proxy gas transport costs are based on the cost of gas transport in the respective service territories of the main LSEs. It is calculated in the following manner:

- Units served by SDG&E: The Southern California Gas Company intrastate transportation rate (currently GT-SD) plus the volumetric component of the SDG&E gas transportation rate for electric generation service, including the ITCS19 (currently GTUEG – SD), or any successor rate for electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.
- Units served by Southern California Gas: The Southern California Gas Company intrastate transportation rate for firm electric generation service, including the ITCS (GT-F) plus the G-ITC Wheeler Ridge Interconnection Access fee, if applicable, or any successor rate for firm electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.
- Units served by PG&E: The PG&E intrastate transportation charge stated in Rate Schedule G-EG, or any successor rate for electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.

19 ITCS means Interstate Transition Cost Surcharges.
deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.\textsuperscript{20}

- Units served by Kern River Pipeline (Kern Delivered pricing): There are no additional transport costs added in the definition of this fuel region because the index is already intended to reflect the delivered cost of gas to the end (Zones 11/12) of the Kern River Gas Transmission (KRGT) system.

C.3 Daily Gas Prices

C.3.1 Standard Calculation Process

Pursuant to tariff section 30.4 and 39.7.1.1.1.3, the CAISO calculates two daily gas price indices for use in the next day’s day-ahead and real-time markets using at least two prices from two or more of the following publications: Natural Gas Intelligence, SNL Energy/BTU’s Daily Gas Wire, Platt’s Gas Daily, and the Intercontinental Exchange. The gas price indices reflect the commodity gas price.

<table>
<thead>
<tr>
<th>Source</th>
<th>Earliest Time Available (PST)</th>
<th>Latest Time Available (PST)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ICE</td>
<td>10:00 AM</td>
<td>12:00 PM</td>
</tr>
<tr>
<td>SNL Energy/BTU Daily</td>
<td>16:00 PM</td>
<td>19:00 PM</td>
</tr>
<tr>
<td>NGI</td>
<td>19:00 PM</td>
<td>2:00 AM (flow date)</td>
</tr>
<tr>
<td>Platt’s</td>
<td>17:00 PM</td>
<td>19:00 PM</td>
</tr>
</tbody>
</table>

The gas price indices for the CAISO footprint are the PG&E Citygate, Southern California (SoCal) Citygate and the Kern River Pipeline hub prices. The CAISO then adds the appropriate transportation adder to create regional gas cost values, plus one region for CAISO, utilized in the CAISO market systems.

\textsuperscript{20} If the Facility does not qualify for service under Rate Schedule G-EG, the applicable rate shall be given by Rate Schedule G-NT.
<table>
<thead>
<tr>
<th>Gas Price Index hubs</th>
<th>Gas Price Index plus regional transportation adder</th>
<th>Base Transportation Cost Rate Schedule Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>PG&amp;E Citygate</td>
<td>PGE1</td>
<td>PG&amp;E ‘Schedule EG’</td>
</tr>
<tr>
<td></td>
<td>PGE2</td>
<td>PG&amp;E ‘Schedule EG’</td>
</tr>
<tr>
<td>SoCal Citygate</td>
<td>SCE1</td>
<td>SoCalGas, ‘Schedule GT-F’</td>
</tr>
<tr>
<td></td>
<td>SCE2</td>
<td>SoCalGas, ‘Schedule GT-F’</td>
</tr>
<tr>
<td></td>
<td>SDGE1</td>
<td>SDG&amp;E ‘Schedule EG’</td>
</tr>
<tr>
<td></td>
<td>SDGE2</td>
<td>SDG&amp;E ‘Schedule EG’</td>
</tr>
<tr>
<td>Kern River Gas, delivered</td>
<td>KRNP&lt;sup&gt;21&lt;/sup&gt;</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>KRNS&lt;sup&gt;22&lt;/sup&gt;</td>
<td>N/A</td>
</tr>
</tbody>
</table>

For the day ahead market calculation, the volume weighted average hub prices from ICE is obtained between 8 AM – 9 AM Pacific Time and used for the next day’s day ahead market. For the real time market, the CAISO calculates the gas price indices each day between 19:00 and 22:00 Pacific Time using natural gas prices published earlier on the same day. The GPIs are used in the next day’s real-time market, which is one day after publication of the GPI.

C.3.2

<sup>21</sup> The GPI for the KRNP region represents the delivered price of gas at the Kern River Pipeline. The Electricity Price Index (EPI) for the KRNP region represents the standby service provided by PG&E system.

<sup>22</sup> The GPI for the KRNS region represents the delivered price of gas at the Kern River Pipeline. The Electricity Price Index (EPI) for the KRNS region represents the standby service provided by SCE system.
C.4 Monthly Gas Prices

The gas price used in the calculation of the DR NBT threshold price is the average of the closing gas prices for the Southern California CityGate, PG&E CityGate and Kern River gas delivery points for the trading days that existed through the Xth day of the current calendar month, for delivery in the next calendar month. The value ‘X’ is configurable; for the example below we will use trading days through the ninth calendar day of the month. The CAISO calculates future gas price indices for use in the calculation of the DR NBT threshold using average from any available of the publications listed in below given table:

<table>
<thead>
<tr>
<th>Source</th>
<th>Earliest Time Available (PST)</th>
<th>Latest Time Available (PST)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ICE</td>
<td>10:00 AM</td>
<td>12:00 PM</td>
</tr>
<tr>
<td>SNL Energy/BTU Daily</td>
<td>16:00 PM</td>
<td>19:00 PM</td>
</tr>
<tr>
<td>NGI</td>
<td>19:00 PM</td>
<td>2:00 AM (flow date)</td>
</tr>
</tbody>
</table>

The calculation takes into account all the above available indices for a hub on any trade day. If there are no indices available for a specific hub/s, then the calculation must use the Henry hub price for that specific hub/s. Below is the table which lists the indices available for each hub:

<table>
<thead>
<tr>
<th>Hub</th>
<th>Fuel regions</th>
<th>ICE</th>
<th>SNL</th>
<th>NGI</th>
</tr>
</thead>
<tbody>
<tr>
<td>PG&amp;E Citygate</td>
<td>PGE2</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
<tr>
<td>SoCal Citygate</td>
<td>SCE1, SCE2, SDG1, SDG2</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
</tr>
</tbody>
</table>

Example

The following example includes detailed steps for calculating the PG&E CityGate gas price. Refer to Figure 1.

1. The Henry Hub gas price is obtained (Column E) for each day the gas was traded (i.e. trading floors open). The gas is traded on all business days which are not a federal holiday. Note that the gas prices for weekend (e.g. 03/03 and 03/04) days are not used in the calculation as they are not trading days.
2. The daily closing gas price for basis swap is obtained. For this example the PG&E CityGate gas delivery point is used. (Column F).
3. The prices obtained in step 1 and 2 above are added together. The added price is shown in column H.
4. On each day, the price calculated in step 3 on that day and all the days prior to that day, are averaged together. In the example shown in Figure 1, the values in Column F are the average of the values in column H. Taking the average of the futures prices for PG&E CityGate through the 9th, we get a value of $5.11.

•
•

23 A basis swap price for any gas delivery point is the price difference between Henry Hub and that gas delivery point.
The same steps 2-4 can be repeated to calculate the gas price for Southern California CityGate.

- Figure 1: Showing the inputs that go into the calculation of PG&E CityGate Gas Price for the delivery month of April 2012 as it was traded on each trading day in March 2012.

<table>
<thead>
<tr>
<th>Closing Date</th>
<th>Trade Month</th>
<th>Henry Hub Price</th>
<th>Basis Swap at PG&amp;E CityGate</th>
<th>Gas Delivery Price at PG&amp;E CityGate</th>
<th>Avg PG&amp;E (month-to-date)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3/1/2012</td>
<td>Apr-12</td>
<td>$4.18</td>
<td>$0.66</td>
<td>$4.84</td>
<td>4.84</td>
</tr>
<tr>
<td>3/2/2012</td>
<td>Apr-12</td>
<td>$4.17</td>
<td>$0.44</td>
<td>$4.61</td>
<td>4.73</td>
</tr>
<tr>
<td>3/5/2012</td>
<td>Apr-12</td>
<td>$4.55</td>
<td>$0.51</td>
<td>$4.66</td>
<td>4.84</td>
</tr>
<tr>
<td>3/6/2012</td>
<td>Apr-12</td>
<td>$4.92</td>
<td>$0.49</td>
<td>$5.41</td>
<td>4.98</td>
</tr>
<tr>
<td>3/7/2012</td>
<td>Apr-12</td>
<td>$4.66</td>
<td>$0.42</td>
<td>$5.08</td>
<td>5.00</td>
</tr>
<tr>
<td>3/8/2012</td>
<td>Apr-12</td>
<td>$4.98</td>
<td>$0.47</td>
<td>$5.45</td>
<td>5.08</td>
</tr>
<tr>
<td>3/9/2012</td>
<td>Apr-12</td>
<td>$4.69</td>
<td>$0.65</td>
<td>$5.34</td>
<td>5.11</td>
</tr>
<tr>
<td>3/12/2012</td>
<td>Apr-12</td>
<td>$4.71</td>
<td>$0.64</td>
<td>$5.35</td>
<td>5.14</td>
</tr>
<tr>
<td>3/13/2012</td>
<td>Apr-12</td>
<td>$4.66</td>
<td>$0.56</td>
<td>$5.22</td>
<td>5.15</td>
</tr>
<tr>
<td>3/14/2012</td>
<td>Apr-12</td>
<td>$4.61</td>
<td>$0.58</td>
<td>$5.19</td>
<td>5.16</td>
</tr>
<tr>
<td>3/15/2012</td>
<td>Apr-12</td>
<td>$4.52</td>
<td>$0.65</td>
<td>$5.17</td>
<td>5.16</td>
</tr>
<tr>
<td>3/16/2012</td>
<td>Apr-12</td>
<td>$4.25</td>
<td>$0.50</td>
<td>$4.75</td>
<td>5.12</td>
</tr>
<tr>
<td>3/19/2012</td>
<td>Apr-12</td>
<td>$4.89</td>
<td>$0.68</td>
<td>$5.57</td>
<td>5.16</td>
</tr>
<tr>
<td>3/20/2012</td>
<td>Apr-12</td>
<td>$4.85</td>
<td>$0.45</td>
<td>$5.31</td>
<td>5.17</td>
</tr>
<tr>
<td>3/21/2012</td>
<td>Apr-12</td>
<td>$4.89</td>
<td>$0.65</td>
<td>$5.54</td>
<td>5.19</td>
</tr>
<tr>
<td>3/22/2012</td>
<td>Apr-12</td>
<td>$4.64</td>
<td>$0.52</td>
<td>$5.16</td>
<td>5.19</td>
</tr>
<tr>
<td>3/23/2012</td>
<td>Apr-12</td>
<td>$4.75</td>
<td>$0.56</td>
<td>$5.32</td>
<td>5.20</td>
</tr>
<tr>
<td>3/26/2012</td>
<td>Apr-12</td>
<td>$4.08</td>
<td>$0.65</td>
<td>$4.73</td>
<td>5.17</td>
</tr>
<tr>
<td>3/27/2012</td>
<td>Apr-12</td>
<td>$4.15</td>
<td>$0.65</td>
<td>$4.80</td>
<td>5.15</td>
</tr>
<tr>
<td>3/28/2012</td>
<td>Apr-12</td>
<td>$4.68</td>
<td>$0.63</td>
<td>$5.29</td>
<td>5.16</td>
</tr>
<tr>
<td>3/29/2012</td>
<td>Apr-12</td>
<td>$4.25</td>
<td>$0.69</td>
<td>$4.95</td>
<td>5.15</td>
</tr>
<tr>
<td>3/30/2012</td>
<td>Apr-12</td>
<td>$4.17</td>
<td>$0.67</td>
<td>$4.84</td>
<td>5.14</td>
</tr>
</tbody>
</table>

The final step is to calculate the average of the two month-to-date prices for the identified gas delivery points. Assume for this example we calculate an average price of $5.17 for Southern California CityGate. The gas price to be used in the calculation of the DR NBT Threshold price is:

\[
\frac{(5.11+5.17)}{2} = 5.14
\]
The gas price used in the projected proxy cost calculation is derived in a similar manner. Refer to Appendix Attachment G.
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.

An SC may modify the ranking of the three options for calculating the DEB up to two times during any 365-day period. If an 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 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. If a Resource has ranked the Negotiated Rate Option as the first choice, the complete curve of 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. 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 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 Resource. Since the methodology for calculating the LMP-Based DEB needs predefined segments and one of the other two methods 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.

In the event that a resource fails the Feasibility Test, the second choice will be substituted for that particular segment. Finally, adjustments are made to ensure that the staircase bid curve is monotonically increasing.
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 DEB Price Calculation

If a resource has passed the Eligibility Test and a DEB segment has passed the Feasibility Test, the 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.

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.
**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 Gas Price Index 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 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. This figure will then be multiplied by a configurable scalar (e.g., 110%), plus the DEB Adder if applicable, to produce the Cost-Based DEB24.

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 value 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.

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24 CAISO continues to use the current emissions chargeback process. CAISO only reimburses generators for legitimately incurred emissions costs due to CAISO dispatches.
D.5.1 Average Heat Rate Curve

Generator units are required to submit to CAISO the Average Heat Rates (Btu/kWh) measured for at least 2 and 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. An Average Cost Curve is used in place of the Heat Rate Curve for a non-gas fueled unit. 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 Curve

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. The resulting incremental heat rate segments are a step function due to use of piece-wise linear average heat rate curve. Two average heat rate pairs yield one incremental heat rate segment that spans across two operating points. The first step is to covert the average heat rate to requirement of heat input (Btu/h) for each operating point by multiplying the average heat rate with the MW of the operating level. The actual incremental heat rate is then derived as dividing the change of requirement of heat input 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 calculated from average rates is provided below.

\[
IHR_{Sn}^{ini} = \frac{AvgHR_{n+1} \times MW_{n+1} - AvgHR_{n} \times MW_{n}}{MW_{n+1} - MW_{n}}
\]

Where:

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

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

- \( MW_{n} \), \( MW_{n-1} \) are the generator MW output levels at the operating points \( n \) (higher level) and \( n - 1 \) (lower), respectively.
D.5.3 Adjustment of Incremental Heat Rate

Initial incremental heat rates 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 segments that correspond to operating ranges below 80% of the units’ maximum operating capacity (PMax).

Specifically, initial incremental heat rates calculated using the equations in Section D.4.1.2 will be adjusted if necessary so that the resulting incremental heat rates (Btu/kWh) 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.

\[ Cap_{S_n} = \max(AvgHR_n, AvgHR_{n+1}) \]

\[ IHR_{S_n}^{adjusted} = \min(IHR_{S_n}^{ini}, Cap_{S_n}) \]

Where:

- \( Cap_{S_n} \) is the maximum limit for segment \( S_n \);
- \( IHR_{S_n}^{adjusted} \) is the adjusted incremental heat for segment \( S_n \).

Examples of this adjustment are provided in Attachment J.

D.5.4 Operation and Maintenance Adder

The Operation and Maintenance (O&M) cost adder is an amount in terms of $/MW. 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.

FMU Bid Adder

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

Eligibility for DEB Adder

A resource is eligible to have a DEB 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.5.5 Summary Example

The following example summarizes how the Cost-Based DEB is calculated for an individual segment of a unit’s heat rate curve.

For a gas-fired Combined Cycle Gas Turbine (CCGT) with a segment with an 8,000 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. 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.

\[ \{(\text{HR} \times \text{GPI}) + \text{O&M} + \text{GMC} \} \times 1.1 \} + \text{DEBA (if eligible)} \]

\[ \{(8 \times 5) + 2.80 + 0.50 \} \times 1.1 \} + 0 \]
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 would use documentation supplied by the market participant and its discretion to determine the 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 would supply the distillate price index and the generator would provide the Average Heat Rate.

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.

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.

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)

SC submits request for Negotiated DEB (N-DEB)

CAISO Accepts?

Yes

SC submits revised request for N-DEB?

No

Yes

SC can file proposed DEB with FERC after 60 days from initial submission of request for N-DEB

CAISO determines if temporary DEB if appropriate pending final resolution of Negotiated Option

N-DEB implemented within three (3) Business Days

N-DEB filed with FERC within first seven (7) days of next calendar month

CAISO determines temporary DEB based on (1) operating cost, opportunity cost and other data provided by the SC (2) estimated operating or opportunity costs based on best information available to CAISO, and/or (3) an appropriate average of competitive bids from one or more similar facilities

Temporary DEB implemented within three (3) Business Days

Temporary Bid filed with FERC within first seven (7) days of next calendar month
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. A negotiated default energy bid will be reviewed and potentially renegotiated or terminated under the following circumstances:

1. **Change in scheduling coordinator**
   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.7 RMR Units

An RMR unit will have its Bids mitigated to the RMR Proxy Bids which are determined by the independent entity for each RMR resource using specific RMR contract values that have been filed with FERC. RMR contractual capacity is the capacity between a unit's 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.
Attachment E

BID ADDER CALCULATIONS
E. Calculation of Bid Adder

The Local Market Power Mitigation (LMPM) procedures has a provision for the application of a Bid Adder to Generating Units that are frequently mitigated (FMUs). This Bid Adder is intended to provide additional revenue adequacy for Generating Units that are frequently mitigated to their variable costs (plus a 10% buffer to account for potential inaccuracies in accounting for variable costs) and, in particular, is intended to cover those costs that would be avoidable if Units were not maintained in state of readiness to generate Energy (namely fixed O&M and overhaul costs).

E.1 Eligibility Criteria for Bid Adder

Each month, CAISO establishes whether a unit is Frequently Mitigated and eligible to have the FMU Bid Adder applied to its Default Energy Bid. The eligibility is established on a monthly basis according to standard criteria.

A unit is designated as a Frequently Mitigated Unit (FMU) if the following conditions are met:

- Unit is mitigated in over 80% of its run hours over a rolling 12-month period.
- Any hour in which a unit has positive metered output count as a run hour.
- Any hour in which a unit had a mitigated bid segment dispatched count as a mitigated hour.
- Unit does not have a capacity contract with CAISO.

The purpose for establishing a threshold for minimum run hours is to provide revenue adequacy for Generating Units that are unable to recover their avoidable fixed costs due to frequent mitigation while addressing potential situations where a unit may run very infrequently and therefore its inability to recover going forward fixed costs is due to its infrequent operation as opposed to the local market power mitigation. To the extent that infrequently run units are critical for meeting local reliability needs, their revenue requirements should be addressed through a local RA contract.

CAISO limits application of the Bid Adder to the cost-based DEB option. If a Generating Unit owner is eligible for a Bid Adder but has elected the LMP based DEB option, they have the “choice” of having a new DEB based on the cost-based option plus the adder or keeping the LMP based option. This limit preserves the avoidable cost compensation property of the bid adder while removing any “double payment” of avoidable cost.
E.2  Calculation of the Default Bid Adder Value

Once CAISO determines that a unit is eligible for the Bid Adder, that Generating Unit’s cost-based Default Energy Bid includes either the default Bid Adder value or a unit-specific Bid Adder value arrived at through consultation.

The default Bid Adder value ($/MWh) is calculated as the ratio of Annual Avoidable Fixed Costs divided by Annual Expected Energy Production.

For CTs, CAISO calculates the Bid Adder value resulting from using the Fixed O&M cost figures for a new CT in California that are reported Appendix D of the California Energy Commission 2003 Final Staff Report titled “Comparative Cost of California Central Station Electricity Generation Technologies”. This report calculates Fixed O&M costs of $20/kW-Yr for a new 100 MW CT that has a capacity factor of 9.4%. Using these figures, the Annual Fixed O&M Cost is $2,000,000 and the Annual Expected Energy Production is 82,344 MWh. This results in a default Bid Adder value of $24/MWh.

Note that the proposed Bid Adder value of $24/MWh is for use as a default value and that unit owners have the option to present cost data reflecting their unit specific avoidable costs to CAISO and negotiate a different Bid Adder value for that unit.

E.3  Units with a Portion of Capacity Contracted under Resource Adequacy

Partially-contracted RA units are treated in the following two ways:

Units with some portion of their capacity under an RA contract are not prohibited from receiving a Bid Adder (as stated above).

If a partial-RA unit meets the eligibility criteria to receive a Bid Adder, the Bid Adder (default or negotiated) is pro-rated to reflect the proportion of that unit’s capacity that is not contracted. For example, an FMU with 75% of its capacity under an RA contract would receive a $6/MWh Bid Adder as the default.

The pro-rated Bid Adder for partial-RA units are applied to the entire cost-based DEB.
Attachment F

Examples of Generated Bid Curves
Example 1

In this example, a gas combined-cycle generator with average heat rates (Btu/kWh) measured at five operating levels (MW) is used to demonstrate the procedure.

<table>
<thead>
<tr>
<th>Operating Point (n)</th>
<th>Operating Level</th>
<th>Average Heat Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>164</td>
<td>7,643</td>
</tr>
<tr>
<td>2</td>
<td>298</td>
<td>7,485</td>
</tr>
<tr>
<td>3</td>
<td>340</td>
<td>7,643</td>
</tr>
<tr>
<td>4</td>
<td>480</td>
<td>7,000</td>
</tr>
<tr>
<td>5</td>
<td>590</td>
<td>7,485</td>
</tr>
</tbody>
</table>

Step 1. Calculate Initial Incremental Heat Rate

\[ IHR_{S1}^{ini} = \frac{AvgHR_2 * MW_2 - AvgHR_1 * MW_1}{MW_2 - MW_1} = \frac{7485 * 298 - 7643 * 164}{298 - 164} = 7292 \text{ Btu/kWh} \]

\[ IHR_{S2}^{ini} = \frac{AvgHR_3 * MW_3 - AvgHR_2 * MW_2}{MW_3 - MW_2} = \frac{7643 * 340 - 7485 * 298}{340 - 298} = 8764 \text{ Btu/kWh} \]

\[ IHR_{S3}^{ini} = \frac{AvgHR_4 * MW_4 - AvgHR_3 * MW_3}{MW_4 - MW_3} = \frac{7000 * 480 - 7643 * 340}{480 - 340} = 5438 \text{ Btu/kWh} \]

\[ IHR_{S4}^{ini} = \frac{AvgHR_5 * MW_5 - AvgHR_4 * MW_4}{MW_5 - MW_4} = \frac{7485 * 590 - 7000 * 480}{590 - 480} = 9601 \text{ Btu/kWh} \]
Results of these calculations are summarized below.

<table>
<thead>
<tr>
<th>Operating Point, n</th>
<th>Operating Level</th>
<th>Average Heat Rate</th>
<th>Segment</th>
<th>Initial Incremental</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>164</td>
<td>7,643</td>
<td>1</td>
<td>7,292</td>
</tr>
<tr>
<td>2</td>
<td>298</td>
<td>7,485</td>
<td>2</td>
<td>8,764</td>
</tr>
<tr>
<td>3</td>
<td>340</td>
<td>7,643</td>
<td>3</td>
<td>5,438</td>
</tr>
<tr>
<td>4</td>
<td>480</td>
<td>7,000</td>
<td>4</td>
<td>9,601</td>
</tr>
<tr>
<td>5</td>
<td>590</td>
<td>7,485</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Step2. Adjustment of Incremental Heat Rate

First, for each segment, the maximum incremental heat rate for each segment (Cap) is calculated by taking the maximum of the average heat rates for the two operating points used to calculate the incremental heat rate segment.

\[
Cap_{s1} = \max(AvgHR_1, AvgHR_2) = \max(7643, 7485) = 7643 \text{ Btu/kWh}
\]

\[
Cap_{s2} = \max(AvgHR_2, AvgHR_3) = \max(7485, 7643) = 7643 \text{ Btu/kWh}
\]

\[
Cap_{s3} = \max(AvgHR_3, AvgHR_4) = \max(7643, 7000) = 7643 \text{ Btu/kWh}
\]

\[
Cap_{s4} = \max(AvgHR_4, AvgHR_5) = \max(7000, 7485) = 7485 \text{ Btu/kWh}
\]

Since the Cap is applied only to segments below 80% of Pmax, the Operating Level Percentage of Pmax is computed as follows.

\[
OperatingLevel_{1\%} = \frac{OperatingLevel_1}{P_{max}} = \frac{164}{590} = 27.8\%
\]

\[
OperatingLevel_{2\%} = \frac{OperatingLevel_2}{P_{max}} = \frac{298}{590} = 50.5\%
\]

\[
OperatingLevel_{3\%} = \frac{OperatingLevel_3}{P_{max}} = \frac{340}{590} = 57.6\%
\]
\[ \text{OperatingLevel}_4 \% = \frac{\text{OperatingLevel}_4}{P_{\text{max}}} = \frac{480}{590} = 81.4\% \]

\[ \text{OperatingLevel}_5 \% = \frac{\text{OperatingLevel}_5}{P_{\text{max}}} = \frac{590}{590} = 100\% \]

For each segment representing operating levels below 80% of the unit’s Pmax, the initial incremental heat rate is then adjusted so they do not exceed the Cap calculated for the segment:

\[ IHR_{51}^{\text{adjusted}} = \min(IHR_{51}^{\text{ini}}, Cap_{51}) = \min(7292,7643) = 7292 \text{ Btu/kWh} \]

\[ IHR_{52}^{\text{adjusted}} = \min(IHR_{52}^{\text{ini}}, Cap_{52}) = \min(8764,7643) = 7643 \text{ Btu/kWh} \]

\[ IHR_{53}^{\text{adjusted}} = \min(IHR_{53}^{\text{ini}}, Cap_{53}) = \min(5438,7643) = 5438 \text{ Btu/kWh} \]

\[ IHR_{54}^{\text{adjusted}} = \min(IHR_{54}^{\text{ini}}, Cap_{54} \text{ Not Applicable } \text{OperatingLevel}_4 = 81.4\% \geq 80\%) \]

\[ = 9601 \text{ Btu/kWh} \]

Results of these calculations are summarized in the table and figure below.
<table>
<thead>
<tr>
<th>Operating Point (n)</th>
<th>Operating Level</th>
<th>Average Heat Rate</th>
<th>Segment</th>
<th>Initial Incremental Heat Rate</th>
<th>Cap</th>
<th>Operating Level % of Pmax</th>
<th>Adjusted Incremental Heat Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>164</td>
<td>7643</td>
<td>1</td>
<td>7292</td>
<td>7643</td>
<td>27.8%</td>
<td>7292</td>
</tr>
<tr>
<td>2</td>
<td>298</td>
<td>7485</td>
<td>2</td>
<td>8764</td>
<td>7643</td>
<td>50.5%</td>
<td>7643</td>
</tr>
<tr>
<td>3</td>
<td>340</td>
<td>7643</td>
<td>3</td>
<td>5438</td>
<td>7643</td>
<td>57.6%</td>
<td>5438</td>
</tr>
<tr>
<td>4</td>
<td>480</td>
<td>7000</td>
<td>4</td>
<td>9601</td>
<td>7485</td>
<td>81.4%</td>
<td>9601</td>
</tr>
<tr>
<td>5</td>
<td>590</td>
<td>7485</td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
<td></td>
</tr>
</tbody>
</table>

![Heat Rate Graph](image-url)
Step 3. Calculate Incremental Cost Curve

The adjusted incremental heat rate curve is then combined with an O&M cost adder and 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 component divided by the bid segment MW size, to calculate the incremental cost curve. This example assumes that the gas price is $4.50/mmBTu and the proxy gas transport cost is $.50, making a GPI of $5/mmBTU. The following example assumes a $2/MWh O&M adder and a $0.50 GMC adder. It is assumed this unit is not eligible for the DEBA.

Step 4. Left-to-Right Adjustment

Finally, the Left-To-Right Adjustment is applied 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 is merged to the price of the segment immediately on the left.

Results of calculations in Steps 3 and 4 are illustrated in the table and figure below.

<table>
<thead>
<tr>
<th>Segment</th>
<th>Operating Range</th>
<th>Adjusted Incremental Heat Rate</th>
<th>Incremental Cost</th>
<th>Incremental Cost After Right-to-Left Adjustment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>164-297</td>
<td>7292</td>
<td>$38.96</td>
<td>$38.96</td>
</tr>
<tr>
<td>2</td>
<td>298-339</td>
<td>7643</td>
<td>$40.72</td>
<td>$40.72</td>
</tr>
<tr>
<td>3</td>
<td>340-479</td>
<td>5438</td>
<td>$29.69</td>
<td>$40.72</td>
</tr>
<tr>
<td>4</td>
<td>480-589</td>
<td>9601</td>
<td>$50.51</td>
<td>$50.51</td>
</tr>
</tbody>
</table>
Note, if the resource is subject to a greenhouse gas compliance obligation as indicated in the Master File, the CAISO will add to this curve an incremental energy curve representing the cost of meeting that obligation. To cover that case, this example is continued in Appendix Attachment K.
Example 2

In this example, a gas peaker generator with average heat rates (Btu/kWh) measured at ten operating levels (MW) is used to demonstrate the procedure.

Results of heat rates calculations described in Steps 1 and 2 of Example 1 are shown in the table and figure below.

<table>
<thead>
<tr>
<th>Operating Point, n</th>
<th>Operating Level (MW)</th>
<th>Average Heat Rate</th>
<th>Segment</th>
<th>Incremental Heat Rate</th>
<th>Cap</th>
<th>Operating Level % of Pmax</th>
<th>Adjusted Incremental Heat Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>25</td>
<td>12100</td>
<td>1</td>
<td>6679</td>
<td>12100</td>
<td>26.8%</td>
<td>6679</td>
</tr>
<tr>
<td>2</td>
<td>34</td>
<td>10700</td>
<td>2</td>
<td>8033</td>
<td>10700</td>
<td>36.2%</td>
<td>8033</td>
</tr>
<tr>
<td>3</td>
<td>40</td>
<td>10300</td>
<td>3</td>
<td>9400</td>
<td>10300</td>
<td>42.6%</td>
<td>9400</td>
</tr>
<tr>
<td>4</td>
<td>45</td>
<td>10200</td>
<td>4</td>
<td>10200</td>
<td>10200</td>
<td>47.9%</td>
<td>10200</td>
</tr>
<tr>
<td>5</td>
<td>47</td>
<td>10200</td>
<td>5</td>
<td>41867</td>
<td>12100</td>
<td>50.0%</td>
<td>12100</td>
</tr>
<tr>
<td>6</td>
<td>50</td>
<td>12100</td>
<td>6</td>
<td>6811</td>
<td>12100</td>
<td>53.2%</td>
<td>6811</td>
</tr>
<tr>
<td>7</td>
<td>68</td>
<td>10700</td>
<td>7</td>
<td>8033</td>
<td>10700</td>
<td>72.3%</td>
<td>8033</td>
</tr>
<tr>
<td>8</td>
<td>80</td>
<td>10300</td>
<td>8</td>
<td>9400</td>
<td>10300</td>
<td>85.1%</td>
<td>9400</td>
</tr>
<tr>
<td>9</td>
<td>90</td>
<td>10200</td>
<td>9</td>
<td>10200</td>
<td>10200</td>
<td>95.7%</td>
<td>10200</td>
</tr>
<tr>
<td>10</td>
<td>94</td>
<td>10200</td>
<td></td>
<td></td>
<td></td>
<td>100.0%</td>
<td></td>
</tr>
</tbody>
</table>
Results of incremental cost curve calculations described in Steps 3 and 4 of Example 1 are shown in the table and figure below. This example also assumes that the gas price is $4.50/mmBTU and the proxy gas transport cost is $.50, making a GPI of $5/mmBTU. The following example assumes a $4/MWh O&M adder and a $0.50 GMC adder. It is assumed this unit is not eligible for the DEBA.

<table>
<thead>
<tr>
<th>Segment</th>
<th>Operating Range</th>
<th>Adjusted Incremental Heat Rate</th>
<th>Incremental Cost</th>
<th>Incremental Cost After Right-to-Left Adjustment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>25-33</td>
<td>6679</td>
<td>$37.90</td>
<td>$37.90</td>
</tr>
<tr>
<td>2</td>
<td>34-39</td>
<td>8033</td>
<td>$44.67</td>
<td>$44.67</td>
</tr>
<tr>
<td>3</td>
<td>40-44</td>
<td>9400</td>
<td>$51.50</td>
<td>$51.50</td>
</tr>
<tr>
<td>4</td>
<td>45-46</td>
<td>10200</td>
<td>$55.50</td>
<td>$55.50</td>
</tr>
<tr>
<td>5</td>
<td>47-49</td>
<td>12100</td>
<td>$65.00</td>
<td>$65.00</td>
</tr>
<tr>
<td>6</td>
<td>50-67</td>
<td>6811</td>
<td>$38.56</td>
<td>$65.00</td>
</tr>
<tr>
<td>7</td>
<td>68-79</td>
<td>8033</td>
<td>$44.67</td>
<td>$65.00</td>
</tr>
<tr>
<td>8</td>
<td>80-89</td>
<td>9400</td>
<td>$51.50</td>
<td>$65.00</td>
</tr>
<tr>
<td>9</td>
<td>90-94</td>
<td>10200</td>
<td>$55.50</td>
<td>$65.00</td>
</tr>
</tbody>
</table>
Attachment G

MAXIMUM START-UP AND MINIMUM LOAD VALUES UNDER THE REGISTERED AND PROXY COST OPTIONS
G Registered and Proxy Cost Options

This attachment explains how Start-up and Minimum Load Costs are calculated under the Registered and Proxy Cost options and the maximum allowable values for each. Only resources with use-limited capacity may select the Registered Cost Option, pursuant to tariff section 30.4. See Attachment H for Transition Cost calculations for multi-stage generating resources.

In case market-based rate authority is suspended, the Scheduling Coordinator responsible for submitting the resource’s Minimum Load and Start-Up Costs subject to Appendix II of the tariff will not be entitled to select the Registered Cost option available under Section 30.4.1.2 and can only select the Proxy Cost option as specified in Section 30.4.1.1 of the CAISO Tariff for their Minimum Load and Start-Up Costs. If the resource lacks a Start-Up or Minimum Load Cost in any market intervals, the CAISO will insert the Start-Up or Minimum Load Costs calculated based on the Proxy Cost option.

G.1 Registered Cost Option

Units selecting the Registered Cost Option in the Master File must also submit values for Start-up and Minimum Load Costs in the Master File, as described in Attachment B. Multi-Stage Generating units selecting the Register Cost Option in the Master File must also submit values for Transition Costs in the Master File, as described in Attachment B.

Before approving Start-up and Minimum Load Cost values submitted under the Registered Cost Option, the Master File analyst will review the values to determine if they are within the allowable levels.

- Start-Up, Minimum Load, and Transition Costs\(^\text{25}\) under the Registered Cost Option may not exceed 150 percent of the unit’s Projected Proxy Cost for Start-Up, Minimum Load, and Transition Costs.

The registered Start-up, Minimum Load, and Transition Cost values for units selecting the Registered Cost Option may not be modified for a period of 30 days after becoming effective. However, the SC may switch to the Proxy Cost Option during this period if fuel costs increase such that the unit’s actual Start-up and Minimum Load Costs, as calculated under the Proxy Cost Option, exceed the unit’s registered value under the Registered Cost Option in the Master File. Unit’s switching from the Registered Cost Option to the Proxy Cost Option during this 30 day period must remain on the Proxy Cost Option for the remainder of this 30 day period. Transition Costs will not be evaluated for switching. However, if the Start-up Cost is switched

\(^{25}\) See Attachment H for transition cost calculations.
from Registered to Proxy Cost, then the Transition Costs will also be switched from Registered to Proxy Cost at the same time.

If the Start-up, Minimum Load, or Transition costs exceed the maximum limit after the 30 day period expires, the costs will be lowered to the maximum limit currently in effect, as outlined in the following section.

**Monthly Validation of Registered Costs**

On a monthly basis, the CAISO will review the Master File Start-up, Minimum Load, and Transition Cost values for units that had selected the Registered Cost Option to identify resources that have registered cost values over the allowable cap.

- Within 3 business days following the first day of the month, CAISO will review the existing registered cost values that were in effect on the first of the month and identify those resources that have registered cost values over the allowable cap. NOTE: Resources that had a change to minimum load or startup costs within the previous 30 days will be excluded from this review.

- Within 5 business days following the first day of the month, CAISO will communicate a list of the affected resources to the Scheduling Coordinator (SC) requesting that registered cost values be revised to comply with the new limits.

- The SC will have until the 8th business day of the month to submit a valid revised RDT, with an effective date no later than the 15th business day of the month.

- If the SC has not submitted a valid revised RDT by the 8th business day of the month, the Master File analyst will apply the new registered cost cap using an effective date of the 15th business day of the month.

**CAISO Validation of SC-requested Change to Registered Costs**

A SC may submit a GRDT to change the Start-up, Minimum Load, and Transition Cost values for a resource where these values have not been modified within the previous 30 days.

- The SC submits a GRDT with change(s) to Start-up, Minimum Load, and/or Transition Costs.

- CAISO validates that the requested effective date is no greater than 15 business days from the date of submittal.
• CAISO validates that the costs do not exceed the applicable limit based on the gas price that was posted on the day the SC submitted their request.

• If the requested cost values exceed the cap, CAISO will decline the request.

• If the requested costs are within the applicable limit, and no other validation errors occur, the change will be approved and the affected resource will be excluded from the following monthly validation of registered costs.

G.1.1 Natural Gas Units

G.1.1.1 Maximum Registered Start-up Costs

For purposes of determining maximum Start-up costs that may be approved for gas-fired units under the Registered Cost Option, the projected Start-up costs will be calculated by combining the unit’s Startup fuel and electrical energy consumption curves in the Master File and the projected gas price calculated as described in Section G.2, plus a Grid Management Charge (GMC) adder representing the Market Services Charge and System Operations Charge components. 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), the CAISO will add to the projected Start-up costs the greenhouse gas allowance start-up cost. The cost will be calculated per Attachment K, using the projected Greenhouse Gas Allowance Price described in section G.3. In addition, if the resource has established a major maintenance adder with the CAISO or its designated agent, the CAISO or its designated agent will add a major maintenance cost adder (MMA). See Attachment L for details.

For purposes of this calculation, the cost of any auxiliary power needed for start-up (as indicated in the STARTUP_ENERGY field in the Master File) will be calculated by using an estimated electricity price equal to the projected gas price multiplied by a factor of 10. This represents a projected electricity price during unit start-up or cost of auxiliary power provided by the generator based on a unit with a heat rate of 10,000 Btu/KWh.

Example: Registered Start-up Cost Calculation and Bid Cap for Gas-Fired Resource

An example of this calculation based on a gas price of $8.50/MMBtu is provided in the following table.
For purposes of the GMC adder, assume a PMin of 20 MW, a Start-Up Time Period of 600 minutes, and a GMC adder of $0.50/MWh (made up of a $0.15/MWh Market Services Charge and a $0.35/MWh System Operations Charge). Note that the fastest Start-Up Time Period registered in the Master File is used in this calculation, regardless of segment. In other words, even for warm starts or cold starts, the fastest start-up time will be used. For MSG resources this applies to the configuration, i.e., use the fastest time period registered for the segment, not the entire resource.

Start-Up Cost = (Start-Up Fuel x Gas Price) + (Start-Up Energy x Gas Price x Gas Price Multiplier) + (PMin x Start-Up Time Period in min / 60 min/hour x GMC adder / 2)

Gas Price = 8.50/MMBtu
Gas Price Multiplier = 10

Example of start-up cost calculation (first Start-Up segment):
Start-Up Cost = (1,083 MMBtu x $8.50/MMBtu) + (20MWh x $8.50 MMBtu x 10) + (20 MW x (600 minutes/(60 minutes/hour)) x $0.50/MWh / 2)
= (9,205.5) + (1,700) + (50)
= 10,955.50
= 10,956 (rounded)

Start-Up Costs including a GHG Compliance Obligation:

Start-Up Cost = (Start-Up Fuel x Gas Price) + (Start-Up Energy x Gas Price x Gas Price Multiplier) + (PMin x Start-Up Time Period in min / 60 min/hour x GMC adder / 2) + (Start-Up Fuel x GHG Emission Rate x GHG Allowance Price)

GHG Allowance Price = $15.34/mtCO$_2$e
GHG Emission Rate = 0.053165 mtCO$_2$e/MMBtu

Example of start-up:
Start-Up Cost = (1,083 MMBtu x $8.50/MMBtu) + (20MWh x $8.50 MMBtu x 10) + (20 MW x (600 minutes / (60 minutes/hour)) x $0.50/MWh / 2) + (1,083 MMBtu x 0.053165 mtCO$_2$e/MMBtu x $15.34)
= (9,205.5) + (1,700) + (50) + (883.24)
= 11,838.74
= 11,839 (rounded)

Start-Up Costs including a major maintenance cost adder:

The major maintenance cost adder is a single line item that is added to the Start-Up Cost. Continuing the example above:
Assume major maintenance cost adder calculated by the CAISO is $800.98 (same value applied to all segments).

\[
\text{Start-Up Cost} = \$11,838.74 + \text{major maintenance cost adder} \\
= \$11,838.74 + 800.98 \\
= \$12,639.72 \\
= \$12,640 \text{ (rounded)}
\]

Table G1. Example of Projected Start-up Cost and Maximum Registered Cost Bid Calculation (Gas Price = $8.50/MMBtu)

<table>
<thead>
<tr>
<th></th>
<th>Cooling Time (minutes)</th>
<th>Start-Up Time (minutes)</th>
<th>Start-Up Fuel (MMBtu)</th>
<th>Start-Up Energy (MWh)</th>
<th>Start-Up Cost w/o GHG/MMA ($)</th>
<th>Start-Up Cost with GHG &amp; MMA ($)</th>
<th>Max Start-Up Bid w/o GHG/MMA ($)</th>
<th>Max Start-Up Bid with GHG &amp; MMA ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hot</td>
<td>0</td>
<td>600</td>
<td>1,083</td>
<td>20</td>
<td>$10,956</td>
<td>$12,640</td>
<td>$16,433</td>
<td>$18,960</td>
</tr>
<tr>
<td>Warm</td>
<td>240</td>
<td>1390</td>
<td>1,633</td>
<td>40</td>
<td>$17,396</td>
<td>$19,529</td>
<td>$26,059</td>
<td>$29,294</td>
</tr>
<tr>
<td>Cold</td>
<td>480</td>
<td>1400</td>
<td>2,000</td>
<td>60</td>
<td>$22,217</td>
<td>$24,649</td>
<td>$33,325</td>
<td>$36,973</td>
</tr>
</tbody>
</table>

G.1.1.2 Maximum Registered Cost Minimum Load Costs

For purposes of determining maximum Minimum Load Cost that may be approved for gas-fired units under the Registered Cost Option, the projected Minimum Load Cost will be calculated using the unit’s Minimum Load Heat Rate and the projected gas price calculated as described in Section G.1.2, plus a GMC adder made up of the Market Services Charge and System Operations Charge components and a third value representing the Bid Segment Fee component divided by the resource Pmin. 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), the CAISO will add to the projected Minimum Load Cost the Greenhouse gas allowance minimum load cost. The cost will be calculated per Attachment K, using the projected Greenhouse Gas Allowance Price described in section G.1.3. In addition, if the resource has a major maintenance adder approved by the CAISO, the CAISO will add a major maintenance cost adder (MMA). See Attachment L for details.

The Minimum Load Cost for a unit cannot exceed the applicable limit of 150% of the unit’s Projected Proxy Cost for Minimum Load Costs. The calculation and an example are provided here.
Projected Minimum Load Cost = (Unit Conversion Factor x Minimum Load Heat Rate x Minimum Operating Level x Gas Price) + (O&M x Minimum Operating Level) + (GMC adder x Minimum Operating Level)

Example:
Gas Price = 8.50/MMBtu
O&M adder = $4/MWh
GMC adder = $0.50/MWh

Minimum Load Cost = \((0.001 \times 14,000 \text{Btu/kWh} \times 20 \text{MW} \times 8.50/\text{MMBtu}) + (4/\text{MWh})^{26} \times 20 \text{MW}) + (0.50/\text{MWh} \times 20 \text{MW})\)
= ($2,380) + ($80) + ($10)
= $2,470

Minimum Load Cost with a GHG component = (Unit Conversion Factor x Minimum Load Heat Rate x Minimum Operating Level x Gas Price) + (O&M x Minimum Operating Level) + (GMC adder x Minimum Operating Level) + (Minimum Operating Level x Unit Conversion Factor x Minimum Load Heat Rate x Emission Rate x GHG Allowance Price)

Example:
Emission Rate = 0.053165 \text{mtCO}_2e/\text{MMBtu}
GHG Allowance Price = $15.34/\text{mtCO}_2e

= \((0.001 \times 14,000 \text{Btu/kWh} \times 20 \text{MW} \times 8.50/\text{MMBtu}) + (4/\text{MWh} \times 20 \text{MW}) + (0.50/\text{MWh} \times 20 \text{MW}) + (20 \text{MW} \times 0.001 \times 14,000 \text{Btu/kWh} \times 0.053165 \text{mtCO}_2e/\text{MMBtu \times 15.34})\)
= ($2,380) + ($80) + (10) + ($228)
= $2,698

Minimum Load Costs including a major maintenance cost adder:

The major maintenance cost adder is a single line item that is added to the Minimum Load cost. Continuing the example above:

Assume major maintenance cost adder calculated by the CAISO is $105.19.
Minimum Load Cost = $2,695 + major maintenance cost adder
= $2,698 + 105
= $2,803

Table G2. Example of Projected Minimum Load Bid and Maximum Bid Calculation
Gas Price = $8.50/MMBtu

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26 This example assumes a $4/MWh O&M adder.
### G.1.2 Gas Price Used in Start-up and Minimum Load Cost Caps

After the twenty-first day of each month, the CAISO will calculate a gas price to be used in calculating maximum Start-up and Minimum Load costs that may be registered by gas units under the Registered Cost Option. The resulting gas price will be posted on the CAISO website by the end of each calendar month. The price will be applicable for any unit submitting or revising a Start-up and Minimum Load value under the Registered Cost Option for the following month until a new gas price is calculated and posted on the CAISO website. The gas price will be calculated as follows.

First, daily closing prices for monthly natural gas futures contracts at Henry Hub for the next month are averaged over the first twenty one days of the month, resulting in a single average for the next calendar month. Closing prices for only the first twenty-one days of the month are used in order to allow at least one week for the calculations to be completed and posted on the CAISO website by the end of each month. The purpose of averaging daily closing prices over this twenty-one day period is to avoid unusually high or low values that may result from taking prices on only one day.

Second, the average monthly price for futures contracts for basis swaps at the PG&E CityGate natural gas delivery point and futures contracts for basis swaps at the SoCal CityGate natural gas delivery point in California are calculated, using data for the first 21 trade dates in the month.

Consistent with the approach used by the CAISO or its designated agent to calculate the GPI for daily spot market prices used to calculate DEBs and bids under the Proxy Cost option, the SoCal CityGate prices are ultimately used for units in the SCE and SDG&E areas, while the PG&E Citygate prices are used for units in the PG&E area.

The next step is to combine the average Henry Hub price and the average basis swap price for each of these two delivery points for each month.

Consistent with the approach used by the CAISO or its designated agent to calculate the GPI for daily spot market prices, the final step is to add the appropriate intra-state transport price.
For units in the SCE and SDG&E areas, the CAISO or its designated agent uses the applicable gas transportation rate from the Southern California Gas Company.\textsuperscript{27}

For units in the PG&E area, the CAISO or its designated agent uses rates from PG&E’s Gas Schedule G-EG for Gas Transportation Service to Electric Generation.\textsuperscript{28}

The source of gas price data used in this calculation will be the Natural Gas Intelligence Daily, or, if necessary, another available source of closing prices for natural gas futures contracts for each trade date.

G.1.3 Greenhouse Gas Allowance Price Used in Start-up and Minimum Load Cost Caps

After the twenty-first day of each month, the CAISO will calculate a projected Greenhouse Gas Allowance Price to be used in calculating maximum Start-up and Minimum Load costs that may be registered by gas units under the Registered Cost Option. The resulting projected Greenhouse Gas Allowance Price will be posted on the CAISO website by the end of each calendar month. The price will be applicable for any unit submitting or revising a Start-up and Minimum Load value under the Registered Cost Option for the following month until a new projected Greenhouse Gas Allowance Price is calculated and posted on the CAISO website.

The projected Greenhouse Gas Allowance Price will be calculated by averaging the daily Greenhouse Gas Allowance Prices from the first twenty days of the month, resulting in a single average for the next calendar month. Closing prices for only the first twenty days of the month are used in order to allow at least one week for the calculations to be completed and posted on the CAISO website by the end of each month. Per the price principles established in Attachment K, the Daily Greenhouse Gas Allowance price is set at the last valid daily price based on two sources if a given day does not have two sources. A Daily Greenhouse Gas Allowance price set using the last valid daily price based on two sources is included in the calculation of the projected Greenhouse Gas Allowance Price. The purpose of averaging daily closing prices over this twenty day period is to avoid unusually high or low values that may result from taking prices on only one day.

\textsuperscript{27} \url{http://www.socalgas.com/regulatory/tariffs/tm2/pdf/GT-F.pdf}.

\textsuperscript{28} \url{http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-EG.pdf}
G.1.4 Non-Gas Units

For non-gas units, maximum Start-up and Minimum Load values under the Registered Cost Option will be based on Start-up and Minimum Load cost information submitted and validated by the CAISO for each unit under the requirements for the Proxy Cost Option, plus a GMC adder representing the Market Services Charge and System Operations Charge components and a third value representing the Bid Segment Fee component divided by the bid segment MW size. The adder is calculated the same as for gas-fired units as explained above. Start-Up and Minimum Load Costs under the Registered Cost Option may not exceed 150 percent of the unit's validated Start-Up and Minimum Load Costs under the Proxy Cost Option.

For non-natural gas-fired resources subject to a greenhouse gas compliance obligation (as indicated by a 'Y' in the 'GHG_COMPLIANCE_OBLIG field in Master File), the SC should include the greenhouse gas allowance cost in the Start-up and Minimum Load cost values submitted under the Registered Cost Option.

The CAISO shall include major maintenance costs for non-natural gas-fired resources that have established a major maintenance adder. See Attachment L for details.

As part of the process of validating Start-Up and Minimum Load Costs submitted under the Proxy cost Option, the CAISO may request additional information from the Scheduling Coordinator.

G.2 Proxy Cost Option

Scheduling Coordinators with resources subject to the Proxy Cost Option must also submit values for Start-up and Minimum Load Cost in the Master File, as described in Attachment B. Multi-stage generating resources must also submit values for Transition Costs in the Master File, as described in Attachment B.

G.2.1 Natural Gas Units

G.2.1.1 Maximum Proxy Cost Start-up Costs

For purposes of determining maximum Start-up costs that may be approved for gas-fired units under the Proxy Cost Option, the calculated Start-up costs will be calculated by combining the

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29 Multi-stage generating resources have both start-up and indicative start-up costs, as described in greater detail in Attachment H. This section refers to both generically as start-up costs.
unit’s Startup fuel and electrical energy consumption curves in the Master File, the daily Gas Price Index calculated as described in Attachment C and the electricity price index as described in attachment M, plus a Grid Management Charge (GMC) adder representing the Market Services Charge and System Operations Charge components. 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), the CAISO will add to the calculated Start-up costs the greenhouse gas allowance start-up cost. The cost will be calculated per Attachment K, using the Greenhouse Gas Allowance Price described in Attachment K. In addition, if the resource has major maintenance expenses approved by the CAISO, the CAISO will add a major maintenance cost adder (MMA). See Attachment L for details.

For purposes of this calculation, the cost of any auxiliary power needed for start-up (as indicated in the STARTUP_ENERGY field in the Master File) will be calculated multiplying the MWh energy input with the Electricity Price Index. See Attachment M for details.

A Scheduling Coordinator may bid Start-up Costs daily. The Start-up Cost bid for a unit cannot exceed the applicable limit of 125 percent of the unit’s calculated Proxy Cost for Start-up Costs. For multi-stage generating resources, a Scheduling Coordinator may bid Transition Costs daily. The Transition Cost bid for a unit cannot exceed the applicable limit of 125 percent of the unit’s calculated Proxy Cost for Transition Costs. If the Scheduling Coordinator does not bid, the CAISO will generate daily bids based on the calculated Proxy Costs.

Example: Proxy Start-up Cost Calculation and Bid Cap for Gas-Fired Resource

An example of this calculation based on a natural gas price index of $8.50/MMBtu is provided in the following table.

For purposes of the GMC adder, assume a PMin of 20 MW, a Start-Up Time Period of 600 minutes, and a GMC adder of $0.50/MWh (made up of a $0.15/MWh Market Services Charge and a $0.35/MWh System Operations Charge). Note that the fastest Start-Up Time Period registered in the Master File is used in this calculation, regardless of segment. In other words, even for warm starts or cold starts, the fastest start-up time will be used. For MSG resources this applies to each configuration. That is, the fastest time period registered for the segment, not the entire resource, will be used.

30 See Attachment H for transition cost calculations.
Start-Up Cost = (Start-Up Fuel x Gas Price) + (Start-Up Energy x Electricity Price Index) + (PMin x Start-Up Time Period in min / 60 min/hour x GMC adder / 2)

Gas price index = 8.50/MMBtu

Example of start-up cost calculation (first Start-Up segment):
Start-Up Cost = (1,083 MMBtu x $8.50/MMBtu) + (20MWh x $80/MWh) + (20 MW x (600 minutes/(60 minutes/hour)) x $0.50/MWh / 2)
= (9,205.5) + (1,600) + (50)
= 10,855.50
= 10,856 (rounded)

Start-Up Costs including a GHG Compliance Obligation:

Start-Up Cost = (Start-Up Fuel x Gas Price) + (Start-Up Energy x Electricity Price Index) + (PMin x Start-Up Time Period in min / 60 min/hour x GMC adder / 2) + (Start-Up Fuel x GHG Emission Rate x GHG Allowance Price)

GHG Allowance Price = $15.34/mtCO$_2$e
GHG Emission Rate = 0.053165 mtCO$_2$e /MMBtu

Example of start-up:
Start-Up Cost = (1,083 MMBtu x $8.50/MMBtu) + (20MWh x $80/MWh) + (20 MW x (600 minutes / (60 minutes/hour)) x $0.50/MWh / 2) + (1083 MMBtu x 0.053165 mtCO$_2$e /MMBtu x $15.34)
= (9,205.5) + (1,600) + (50) + (883.24)
= 11,738.74
= 11,739 (rounded)

Start-Up Costs including a major maintenance cost adder:

The major maintenance cost adder is a single line item that is added to the Start-Up Cost. Continuing the example above:

Assume major maintenance cost adder approved by the CAISO is $800.98 (same value applied to all segments).
Start-Up Cost = $11,738.74 + major maintenance cost adder
= $11,738.74 + 800.98
= $12,539.72
= $12,540 (rounded)
Table G3. Example of Calculated Start-up Cost and Maximum Proxy Cost Bid Calculation (Gas Price = $8.50/MMBtu, EPI = $80/MWh)

<table>
<thead>
<tr>
<th></th>
<th>Cooling Time</th>
<th>Start-Up Time</th>
<th>Start-Up Fuel</th>
<th>Start-Up Energy</th>
<th>Start-Up Cost w/o GHG/MMA ($)</th>
<th>Start-Up Cost with GHG &amp; MMA ($)</th>
<th>Max Start-Up Bid w/o GHG/MMA ($)</th>
<th>Max Start-Up Bid with GHG &amp; MMA ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hot</td>
<td>0</td>
<td>600</td>
<td>1,083</td>
<td>20</td>
<td>$10,856</td>
<td>$12,540</td>
<td>$13,569</td>
<td>$15,675</td>
</tr>
<tr>
<td>Warm</td>
<td>240</td>
<td>1390</td>
<td>1,633</td>
<td>40</td>
<td>$17,196</td>
<td>$19,329</td>
<td>$21,495</td>
<td>$24,161</td>
</tr>
<tr>
<td>Cold</td>
<td>480</td>
<td>1400</td>
<td>2,000</td>
<td>60</td>
<td>$21,917</td>
<td>$24,349</td>
<td>$27,396</td>
<td>$30,436</td>
</tr>
</tbody>
</table>

G.2.1.2 Maximum Proxy Cost Minimum Load Costs

For purposes of determining maximum Minimum Load Cost that may be calculated for gas-fired units under the Proxy Cost Option, the calculated Minimum Load Cost will be calculated using the unit’s Minimum Load Heat Rate and the daily Gas Price Index calculated as described in Attachment C, plus a GMC adder made up of the Market Services Charge and System Operations Charge components and a third value representing the Bid Segment Fee component divided by the resource Pmin. 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), the CAISO will add to the calculated Minimum Load Cost the Greenhouse gas allowance minimum load cost. The cost will be calculated using the Greenhouse Gas Allowance Price described in Attachment K. In addition, if the resource has minimum load major maintenance adder approved by the CAISO, the CAISO will add a major maintenance cost adder (MMA). See Attachment L for details.

A Scheduling Coordinator may submit daily bids for Minimum Load Costs up to the cap of 125 percent of the unit’s calculated Proxy Cost for Minimum Load Costs. If the Scheduling Coordinator does not bid, the CAISO will generate daily bids based on the calculated Proxy Costs. The calculation and an example are provided below.

**Example: Proxy Minimum Load Cost Calculation and Bid Cap for Gas-Fired Resource**

Minimum Load Cost Cap = (Unit Conversion Factor x Minimum Load Heat Rate x Minimum Operating Level x Gas Price) + (O&M x Minimum Operating Level) + (GMC adder x Minimum Operating Level)
Example:
Gas price index = 8.50/MMBtu
O&M adder = $4/MWh
GMC adder = $0.50/MWh

\[ \text{Minimum Load Cost} = (0.001 \times 14,000\text{Btu/kWh} \times 20\text{MW} \times $8.50/\text{MMBtu}) + ($4/\text{MWh}) \times 20\text{MW}) + ($0.50/\text{MWh} \times 20\text{MW}) \]
\[ = ($2,380) + ($80) + ($10) \]
\[ = $2,470 \]

\[ \text{Minimum Load Cost with a GHG component} = (\text{Unit Conversion Factor} \times \text{Minimum Load Heat Rate} \times \text{Minimum Operating Level} \times \text{Gas Price}) + (\text{O&M} \times \text{Minimum Operating Level}) + (\text{GMC adder} \times \text{Minimum Operating Level}) + (\text{Minimum Operating Level} \times \text{Unit Conversion Factor} \times \text{Minimum Load Heat Rate} \times \text{Emission Rate} \times \text{GHG Allowance Price}) \]

Example:
Emission Rate = 0.053165 mtCO\textsubscript{2}e/MBtu
GHG Allowance Price = $15.34/mtCO\textsubscript{2}e

\[ = (0.001 \times 14,000\text{Btu/kWh} \times 20\text{MW} \times $8.50/\text{MMBtu}) + ($4/\text{MWh} \times 20\text{MW}) + ($0.50/\text{MWh} \times 20\text{MW}) + (20\text{MW} \times 0.001 \times 14,000\text{Btu/kWh} \times 0.053165 \text{mtCO2/MBtu} \times 15.34) \]
\[ = ($2,380) + ($80) + ($10) + ($228) \]
\[ = $2,698 \]

**Minimum Load Costs including a major maintenance cost adder:**

The major maintenance cost adder is a single line item that is added to the Minimum Load cost. Continuing the example above:

Assume major maintenance cost adder approved by the CAISO is $105.19.

\[ \text{Minimum Load Cost} = $2,695 + \text{major maintenance cost adder} \]
\[ = $2,698 + 105 \]
\[ = $2,803 \]

**Table G4. Example of Calculated Minimum Load Cost and Maximum Bid Calculation**

<table>
<thead>
<tr>
<th>Minimum Operating</th>
<th>Heat Rate</th>
<th>O&amp;M Cost</th>
<th>Minimum Load Cost</th>
<th>GHG Allowance</th>
<th>Minimum Load Cost</th>
<th>Max MLC Bid w/o</th>
<th>Max MLC Bid with</th>
</tr>
</thead>
</table>

\(^{31}\) This example assumes a $4/MWh O&M adder.
G.2.2 Non-Gas Units

For non-gas units, maximum Start-up and Minimum Load values under the Proxy Cost Option will be based on Start-up, Minimum Load and Transition Cost information submitted and validated by the CAISO for each unit under the requirements for the Proxy Cost Option, plus a GMC adder representing the Market Services Charge and System Operations Charge components and a third value representing the Bid Segment Fee component divided by the bid segment MW size. The adder is calculated the same as for gas-fired units explained above. Start-Up, Minimum Load, and Transition Costs under the Proxy Cost Option may not exceed 125 percent of the unit’s validated Start-Up, Minimum Load, and Transition Costs under the Proxy Cost Option.

For non-natural gas-fired resources subject to a greenhouse gas compliance obligation (as indicated by a ‘Y’ in the ‘GHG_COMPLIANCE_OBLIG field in Master File), the CAISO will add to the calculated Start-up costs the greenhouse gas allowance start-up cost. Start-up greenhouse gas compliance obligation costs may be calculated for non-gas thermal resources as they are for gas-fired resources if sufficient data is submitted in Master File (GHG Emission Rate and start-up fuel requirement (MMBTU/start-up)). The CAISO shall include major maintenance costs for non-natural gas-fired resources which have such costs approved by the CAISO. See Attachment L for details.

As part of the process of validating Start-Up, Minimum Load, and Transition Costs submitted under the Proxy cost Option, the CAISO may request additional information from the Scheduling Coordinator.
Attachment H

Transition Costs for Multi-Stage Generator Resources
H Transition Costs for Multi-Stage Generator Resources

Transition costs are a type of start-up cost specific to multi-stage generators. Transitions costs can be thought of as the costs to “start” a configuration (or conversely the cost savings to “shut down” a configuration). The CAISO uses different terminology to differentiate between changes in configuration when the resource is already “On” versus a plant-level start-up, which turns the resource “On” from the “Off” state per the CAISO tariff definitions.

Multi-Stage Generating Resources that are subject to CAISO Tariff Appendix II must register a transition cost of $0/MWh for all transitions in their transition matrix.

Transition and start-up costs will be calculated and treated as follows:

- A start-up cost is incurred when a resource is turned “On.” If a resource is already On but incrementing between configurations, it may incur a transition cost in the upward direction. For the purposes of this discussion, the “lower” configuration is a configuration with a smaller minimum operating level than the “higher” configuration.
- Transition costs will be calculated as the difference between the “To” and “From” configurations when the resource is increasing from a lower configuration to a higher configuration. Transition costs will only be calculated for possible transition paths. The CAISO does not recognize a downward transition cost. Transition costs must be either a zero or positive number and will default to zero if negative.

Scheduling coordinators may bid start-up costs and transition costs according to whether the resource is subject to the proxy or registered cost option. Under the proxy cost option, scheduling coordinators may bid up to 125 percent of the start-up or transition cost on a daily basis for each configuration. Under the registered cost option, scheduling coordinators may register bids up to 150 percent of the start-up and transition cost, subject to a minimum, 30-day period. Transition costs reflect the fuel input and major maintenance costs, as appropriate, to transition from one configuration to a higher configuration. The fuel input is based on the resource’s actual unit-specific performance parameters, as required in tariff section 30.4.1.1.1.

The process diagram below shows how the transition cost caps are developed under the proxy and registered cost methods.
Step 1: Scheduling Coordinator data submission

Feasible Transitions

A resource that has been registered as an MSG unit will also fill out a transition matrix, which contains operating constraints associated with the feasible transitions between configurations. Scheduling Coordinators must provide all feasible transition paths to the CAISO.

Cost Components and Resource Characteristics

Scheduling Coordinators must provide enough information about each cost component and physical resource characteristic of both start-up and indirect start-up costs for each configuration based on quantifiable and verifiable costs as required in tariff section 30.4.1.1.1. A start-up cost is the cost incurred for a configuration that the resource can directly start into (also referred to as a “startable” configuration). A start-up cost also refers to the cost an MSG incurs when the resource is turned On for the first time. Since an MSG resource can start directly into any of its startable configurations, each has the potential to be the first start-up cost.

An indirect start-up reflects the start of a configuration that cannot be directly started. An indirect start-up cost is only calculated for the purpose of calculating transition costs and will not be used when a resource is turned On (and is not a biddable parameter). An example of a configuration that an MSG resource cannot directly start into is the duct firing capability of a combined cycle resource if the combustion turbine is modeled as the lower configuration and the duct firing is modeled as the higher configuration. The resource would physically need to be near the maximum capability of the combustion turbine in order to access duct firing. Therefore, this resource cannot directly start into the duct firing configuration. For this type of example, a non-negative transition cost can be incurred when the resource transitions from the lower (combustion turbine) to the higher (duct firing) configuration. Even configurations that cannot be directly started can have verifiable physical parameters and/or costs as required in tariff section 30.4.1.1.1. These parameters and/or costs are used to calculate the indirect start-up cost.

Indirect start-up costs have the same components as start-up costs and follow the calculation methodology for the proxy and registered cost options. Please see Attachment G for proxy and the registered cost option calculations. Transition costs must be calculated using the same cost option as the start-up cost methodology selected for the resource as required by tariff section 30.4.

Note that the CAISO tariff does not differentiate between start-up and indirect start-up but refers to both generically as “Start-Up.” This is because the two concepts are treated in essentially the same manner. However, this BPM makes the differentiation to help market participants to provide the correct information.
**INSUFFICIENT DATA**

According to tariff section 30.4.1.1.1, if there is insufficient data for the CAISO to determine the resource’s start-up cost in the lowest startable configuration or one or more components of the resource’s start-up costs (either start-up or indirect start-up) then the CAISO will set the start-up cost or cost component(s) is zero. As part of the validation process, the CAISO may request additional information from the SC before setting a cost to zero.

For configurations higher than the lowest startable configuration, tariff section 30.4.1.1.3 allows the CAISO to use a component associated with the next-lowest MSG configuration, if feasible, to backfill insufficient data.

Costs for higher configurations (*i.e.*, a configuration with a higher Pmin) are *cumulative* with respect to lower configurations. The CAISO broadly considers two types of MSG resources. The first is represented by distinct peakers, steam turbines or machines (such as pumps) while the second is duct firing capacity paired with distinct peakers or turbines. For a peaker, steam turbine or similar machine, the configurations reflect separate, modular machines. For example, configuration 1 reflects running one turbine while configuration 2 reflects running two turbines. Therefore, configuration 2 is approximately double the cost of configuration 1. As described in greater detail below, the transition cost is calculated as the cost difference between the start-up costs of the two configurations.

For MSG resources with duct firing capability, the costs do not uniformly increase from configuration 1 to 2 or from 3 to 4. Unlike starting a separate plant, there is an increase in fuel input to transition to duct firing when the combustion turbine is operating at 85 percent of capacity and small incremental increases in the costs due to the change in the configuration Pmin. Costs in the higher configuration reflecting duct firing should be cumulative of the costs of the lower configuration reflecting the combustion turbine. As described in greater detail below, the transition cost is the cost difference between the two configuration start costs and would reflect the small cost increase for reaching duct firing configuration.

**Step 2: CAISO uses submitted data to calculate transition cost bid caps**

The CAISO calculates transition costs as the difference between two start-up costs for each feasible upward transition. Start-up and indirect start-up cost bid caps will be calculated based on the proxy or registered cost methodology.

Transition cost bid cap calculation will be under the same methodology as that selected for start-up costs in accordance with tariff section 30.4. Since the configuration costs are cumulative, transition costs can only be zero or positive. Any negative transition costs will be replaced with zero pursuant to tariff section 30.4.1.1.5.
Step 3: Scheduling Coordinator subject to daily bids under proxy or registers transition costs under registered cost option, if available

Transition costs are calculated under the same methodology as the MSG resource’s selected start-up cost option. Scheduling coordinators eligible for the registered cost option can register transition costs of up to 150 percent of projected transition costs. Scheduling coordinators under the proxy cost option can bid daily up to 125 percent of the calculated transition cost. A scheduling coordinator may not change its registered cost or change to proxy cost for a minimum 30-day period. The registered cost option has slightly different inputs to the proxy cost option as explained in Attachment G.

H.1 Examples: transition costs for natural gas-fired resources

**Example 1: Natural gas-fired resources with distinct peakers or steam turbines**

Table H1 below shows an illustrative example of the cost items included for a resource, Unit A, with distinct peakers or steam turbines. Unit A has four configurations. Only configurations 1 and 3 are directly startable and all transition paths are possible except from 2 to 4. In this example, a new configuration entails starting a new peaker or steam turbine. Therefore, most of the costs and physical parameters approximately double from the first to the second configuration. The CAISO expects that all the columns in yellow are verifiable costs and/or verifiable physical parameters of the resource. For example, the CAISO should be able to verify the heat input, start-up energy, configuration Pmin, and start-up time for each configuration. The CAISO clarifies that the heat input is the amount to reach the Pmin of the peaker or steam turbine. This is different from the transition heat input which is the difference in heat input between the configurations. Each higher configuration should be presented as cumulative costs or amounts from the lower configurations.

The non-highlighted columns are costs that remain the same for all configurations and are provided by the CAISO, such as the daily gas price index under the proxy cost methodology or the projected gas price based on monthly natural gas price futures.

<table>
<thead>
<tr>
<th>Config ID</th>
<th>Configuration</th>
<th>Heat input (MMBtu)</th>
<th>Gas price ($/MMBtu)</th>
<th>GHG price</th>
<th>GHG emission rate</th>
<th>Major maint. adder</th>
<th>Config Pmin</th>
<th>Config startup time</th>
<th>GMC</th>
<th>Startup energy (MWh)</th>
<th>Elec. price index ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UnitA_1</td>
<td>1 – Startable</td>
<td>80</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$250</td>
<td>50</td>
<td>20</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
</tr>
<tr>
<td>UnitA_2</td>
<td>2 – NOT startable</td>
<td>160</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$550</td>
<td>100</td>
<td>20</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
</tr>
</tbody>
</table>
Table H1 assumes that the CAISO has enough information from the Scheduling Coordinator to calculate each start-up and indirect start-up cost. As noted above, if information is insufficient to calculate configuration level data (aside from the lowest configuration) the CAISO may use information from the next lowest configuration to backfill. Table H2 below provides an illustrative example where the data in yellow (for the startable configurations) has been provided but the data in orange (for the indirect start-ups) has not be provided but is instead copied from the next lowest configuration. As discussed in greater detail later, not providing data for certain start-up or indirect start-up costs may result in a lower or zero transition cost.

Table H2
Start-up and indirect start-up cost calculation for missing data: peaker or steam turbine

<table>
<thead>
<tr>
<th>Config ID</th>
<th>Configuration</th>
<th>Heat input (MMBtu)</th>
<th>Gas price ($/MMBtu)</th>
<th>GHG emission rate</th>
<th>Major maint. adder</th>
<th>Config startup time</th>
<th>GMC</th>
<th>Start-up energy (MWh)</th>
<th>Elec. price index ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UnitA_1</td>
<td>1 – Startable</td>
<td>80</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$250</td>
<td>50</td>
<td>20</td>
<td>$0.38</td>
</tr>
<tr>
<td>UnitA_2</td>
<td>2 – NOT startable</td>
<td>80</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$250</td>
<td>50</td>
<td>20</td>
<td>$0.38</td>
</tr>
<tr>
<td>UnitA_3</td>
<td>3 – Startable</td>
<td>240</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$1,000</td>
<td>150</td>
<td>20</td>
<td>$0.38</td>
</tr>
<tr>
<td>UnitA_4</td>
<td>4 – NOT startable</td>
<td>240</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$1,000</td>
<td>150</td>
<td>20</td>
<td>$0.38</td>
</tr>
</tbody>
</table>

Step 2: CAISO uses submitted data to calculate transition cost bid caps

Table H3 reproduces the same inputs as Table H1. The last column in blue has been added to calculate the total start-up or indirect start-up cost:

Start-up Cost = (Heat Input or Start-up Fuel x Gas Price) + (Start-Up Energy x Energy Price Index) + (Pmin x Start-Up Time Period in min / 60 min/hour x GMC adder / 2) + (Heat Input or Start-Up Fuel x GHG Emission Rate x GHG Allowance Price) + Major maintenance adder
Table H3  
Start-up and indirect start-up cost calculation: peaker or steam turbine

<table>
<thead>
<tr>
<th>Config ID</th>
<th>Configuration</th>
<th>Heat input (MMBtu)</th>
<th>Gas price ($/MMBtu)</th>
<th>GHG price</th>
<th>GHG emission rate</th>
<th>Major maint. adder</th>
<th>Config Pmin</th>
<th>Config startup time</th>
<th>GMC</th>
<th>Start-up energy (MWh)</th>
<th>Elec. price index ($/MWh)</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>UnitA_1</td>
<td>1 – Startable</td>
<td>80</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$250</td>
<td>50</td>
<td>20</td>
<td>20</td>
<td>$0.38</td>
<td>$1.00</td>
<td>$645</td>
</tr>
<tr>
<td>UnitA_2</td>
<td>2 – NOT startable</td>
<td>160</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$550</td>
<td>100</td>
<td>20</td>
<td>20</td>
<td>$0.38</td>
<td>$1.00</td>
<td>$1,320</td>
</tr>
<tr>
<td>UnitA_3</td>
<td>3 – Startable</td>
<td>240</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$1,000</td>
<td>150</td>
<td>20</td>
<td>20</td>
<td>$0.38</td>
<td>$1.00</td>
<td>$2,145</td>
</tr>
<tr>
<td>UnitA_4</td>
<td>4 – NOT startable</td>
<td>320</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$1,500</td>
<td>200</td>
<td>20</td>
<td>20</td>
<td>$0.38</td>
<td>$1.00</td>
<td>$3,020</td>
</tr>
</tbody>
</table>

Table H4 shows the calculated transition costs based on the start-up and indirect start-up costs shown in Table H3. The calculated transition costs are equal to 100 percent of the calculated start-up costs under the proxy cost option or 100 percent of the projected start-up costs under the registered cost option. All of the transition costs are calculated as the difference between the “To” configuration and “From” configuration start-up and indirect start-up costs. For example, the start-up cost for configuration 1 is $645 and for configuration 2 is $1,320 as shown in the last column of Table H3. If the resource transitions from configuration 1 to 2, it would incur an additional $675 in transition costs shown in the first row, second column of Table H4, which is the difference between the two configuration start-up costs. This unit cannot transition from configuration 2 to 4 so this transition path is not calculated. When the resource stays in configuration 1 it incurs only the start-up for configuration 1. After it transitions, it would only incrementally incur the transition cost to configuration 2. There are no transition costs from a higher to a lower configuration or if the resource stays in the same configuration. As a simplifying assumption, if each configuration has more than one segment, the highest priced segment will be used in the calculation.

Table H4  
Calculated transition cost: peaker or steam turbine

<table>
<thead>
<tr>
<th>“To” configuration</th>
<th>UnitA_1</th>
<th>UnitA_2</th>
<th>UnitA_3</th>
<th>UnitA_4</th>
</tr>
</thead>
<tbody>
<tr>
<td>“From” configuration</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>UnitA_1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>UnitA_2</td>
<td></td>
<td>$675</td>
<td>$1,500</td>
<td>$2,375</td>
</tr>
<tr>
<td>UnitA_3</td>
<td></td>
<td>$825</td>
<td>n/a</td>
<td></td>
</tr>
<tr>
<td>UnitA_4</td>
<td></td>
<td></td>
<td>$875</td>
<td></td>
</tr>
</tbody>
</table>

If information is not provided for each configuration (even if the configuration is not startable), then the ISO will use data from the next lowest available configuration. Refer back to Table H2 where data is missing for configurations 2 and 4. For data missing for configuration 2, the CAISO will use data from configuration 1 and for data missing for configuration 4 the CAISO will use data from configuration 3.
The consequence of not providing data for configurations 2 and 4 (and the CAISO using information from configurations 1 and 3, respectively), is a zero transition cost calculated for transition paths C1 to C2 and C3 to C4, reduced transition cost from C1 to C4, and an increase in transition cost from C2 to C3 because the C2 cost is now lower. Transitioning from C2 to C4 is not possible for this resource. This is shown in Table H5.

**Table H5**

<table>
<thead>
<tr>
<th>“To” configuration</th>
<th>UnitA_1</th>
<th>UnitA_2</th>
<th>UnitA_3</th>
<th>UnitA_4</th>
</tr>
</thead>
<tbody>
<tr>
<td>UnitA_1</td>
<td>$0</td>
<td>$1,500</td>
<td>$1,500</td>
<td></td>
</tr>
<tr>
<td>UnitA_2</td>
<td></td>
<td>$1,500</td>
<td></td>
<td>n/a</td>
</tr>
<tr>
<td>UnitA_3</td>
<td></td>
<td></td>
<td>$1,500</td>
<td></td>
</tr>
<tr>
<td>UnitA_4</td>
<td></td>
<td></td>
<td></td>
<td>$0</td>
</tr>
</tbody>
</table>

Step 3: SC bids under proxy or registers transition costs under registered cost option

Transition costs are calculated under the same methodology as the MSG resource’s selected start-up cost option. Scheduling coordinators eligible for the registered cost option can register transition costs of up to 150 percent of projected transition costs. Scheduling coordinators under the proxy cost option can bid daily up to 125 percent of the calculated transition cost. A scheduling coordinator may not change its registered cost or change to proxy cost for a minimum 30-day period. The registered cost option has slightly different inputs to the proxy cost option as explained in Attachment G.

**EXAMPLE 2: NATURAL GAS-FIRED RESOURCES WITH DUCT FIRING**

Step 1: SC data submission

Table H6 below shows an illustrative example of the cost items included for a resource, Unit B, with duct firing. Unit B has four configurations. Only configurations 1 and 3 can be directly started and configurations 2 and 4 reflect duct firing and cannot be directly started. All transition
paths are possible except from 2 to 4. In order to access the duct firing in configuration 2, the resource will be operating at 85 percent of the capacity of the combustion turbine in configuration 1. Unlike starting a separate unit, the resource needs to increase its energy output from the Pm in configuration 1 (200 MW) through to the Pm in configuration 2 (250 MW) and would be paid for the energy produced in the dispatchable portion of configuration 1 (between 200 and 249 MW). Unlike starting an additional peaker or steam turbine, the main costs incurred for transitioning to duct firing is a small amount of additional fuel input (as opposed to incurring significant major maintenance costs, for example).

The CAISO expects that all the columns in yellow are verifiable costs and/or verifiable physical parameters of the resource. For example, the CAISO should be able to verify the heat input, start-up energy, configuration Pm in, and start-up time for each configuration. The heat input is the amount to reach the Pm in the combustion turbine or duct firing (assuming the combustion turbine supporting the duct firing is near maximum capacity). This is different from the transition heat input which is the difference in heat input between the configurations. Each higher configuration should be presented as cumulative costs or amounts from the lower configurations.

Scheduling Coordinators can establish major maintenance adders by submitting cost information to the CAISO, as described in detail in Attachment L. In this example, there is no additional major maintenance adder for the duct firing configurations. Therefore, the major maintenance costs between configurations 1 and 2 are the same (i.e., the cost for configuration 1 is $11,590 but the incremental cost for configuration 2 is $0 so the cumulative cost, as reflected in the configuration 2 major maintenance adder, is $11,590 + $0 = $11,590). The non-highlighted columns are costs that remain the same for all configurations and are provided by the CAISO, such as the daily gas price index under the proxy cost methodology.

<table>
<thead>
<tr>
<th>Start-up and indirect start-up cost calculation: duct firing</th>
<th>Heat input (MMBtu)</th>
<th>Gas price ($/MMBtu)</th>
<th>Heat input price (MMBtu)</th>
<th>GHG emission rate</th>
<th>Major maint. Adder (MWh)</th>
<th>Config Pm (MW)</th>
<th>Config startup time (hr)</th>
<th>GMC</th>
<th>Elec. price index ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>UnitB_1X1</strong></td>
<td>1 – Startable</td>
<td>1,500</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.055963</td>
<td>$11,590</td>
<td>200</td>
<td>60</td>
<td>$0.38</td>
</tr>
<tr>
<td><strong>UnitB_1X1DF</strong></td>
<td>2 – NOT startable</td>
<td>1,550</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.055963</td>
<td>$11,590</td>
<td>250</td>
<td>60</td>
<td>$0.38</td>
</tr>
<tr>
<td><strong>UnitB_2X1</strong></td>
<td>3 – Startable</td>
<td>2,500</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.055963</td>
<td>$23,180</td>
<td>400</td>
<td>60</td>
<td>$0.38</td>
</tr>
<tr>
<td><strong>UnitB_2X1DF</strong></td>
<td>4 – NOT startable</td>
<td>2,550</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.055963</td>
<td>$23,180</td>
<td>450</td>
<td>60</td>
<td>$0.38</td>
</tr>
</tbody>
</table>
Table H6 assumes that the CAISO has enough information from the Scheduling Coordinator to calculate each start-up and indirect start-up cost. As noted above, if information is missing to calculate configuration level data (aside from the lowest configuration) the CAISO may use information from the next lowest configuration to backfill. Table H7 below provides an example where the data in yellow (for the startable configurations) has been provided but the data in orange (for the indirect start-ups) has not been provided but is instead copied from the next lowest configuration. As discussed in greater detail later, not providing data for certain start-up or indirect start-up costs may result in a lower or zero transition cost.

**Table H7**
Start-up and indirect start-up cost calculation for missing data: duct firing

<table>
<thead>
<tr>
<th>Config ID</th>
<th>Configuration</th>
<th>Heat input (MMBtu)</th>
<th>Gas price ($/MMBtu)</th>
<th>GHG price</th>
<th>GHG emission rate</th>
<th>Major maint. Adder</th>
<th>Config Pmin</th>
<th>Config startup time</th>
<th>GMC</th>
<th>Start-up energy (MWh)</th>
<th>Elec. price index ($/MWh)</th>
<th>Start-up Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>UnitB_1X1</td>
<td>1 – Startable</td>
<td>1.500</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$11,590</td>
<td>200</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
<td>$18,604</td>
</tr>
<tr>
<td>UnitB_1X1DF</td>
<td>2 – NOT startable</td>
<td>1.550</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$11,590</td>
<td>200</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
<td>$18,845</td>
</tr>
<tr>
<td>UnitB_2X1</td>
<td>3 – Startable</td>
<td>2.500</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$23,180</td>
<td>400</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
<td>$34,869</td>
</tr>
<tr>
<td>UnitB_2X1DF</td>
<td>4 – NOT startable</td>
<td>2.550</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$23,180</td>
<td>450</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
<td>$35,110</td>
</tr>
</tbody>
</table>

Table H8 reproduces the same inputs as Table H6. The last column in blue calculates the total start-up or indirect start-up cost:

\[
\text{Start-up Cost} = (\text{Heat Input or Start-up Fuel} \times \text{Gas Price}) + (\text{Start-Up Energy} \times \text{Energy Price Index}) + (\text{Pmin} \times \text{Start-Up Time Period in min} / 60 \text{ min/hour} \times \text{GMC adder} / 2) + (\text{Heat Input or Start-Up Fuel} \times \text{GHG Emission Rate} \times \text{GHG Allowance Price}) + \text{Major maintenance adder}
\]

**Table H8**
Start-up and indirect start-up cost calculation: duct firing

<table>
<thead>
<tr>
<th>Config ID</th>
<th>Configuration</th>
<th>Heat input (MMBtu)</th>
<th>Gas price ($/MMBtu)</th>
<th>GHG price</th>
<th>GHG emission rate</th>
<th>Major maint. Adder</th>
<th>Config Pmin</th>
<th>Config startup time</th>
<th>GMC</th>
<th>Start-up energy (MWh)</th>
<th>Elec. price index ($/MWh)</th>
<th>Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>UnitB_1X1</td>
<td>1 – Startable</td>
<td>1.500</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$11,590</td>
<td>200</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
<td>$18,604</td>
</tr>
<tr>
<td>UnitB_1X1DF</td>
<td>2 – NOT startable</td>
<td>1.550</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$11,590</td>
<td>200</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
<td>$18,845</td>
</tr>
<tr>
<td>UnitB_2X1</td>
<td>3 – Startable</td>
<td>2.500</td>
<td>$4.00</td>
<td>$12.00</td>
<td>0.053963</td>
<td>$23,180</td>
<td>400</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
<td>$34,869</td>
</tr>
</tbody>
</table>

Step 2: CAISO uses submitted data to calculate transition cost bid caps
Table H9 shows the calculated transition costs based on the start-up and indirect start-up costs shown in Table H8. The calculated transition costs do not include headroom (i.e., are 100 percent of the costs). All of the transition costs are calculated as the difference between the “To” configuration and “From” configuration start-up and indirect start-up costs. For example, the start-up cost for configuration 1 is $18,604 and for configuration 2 is $18,845 as shown in the last column of Table H8. If the resource transitions from configuration 1 to 2, it would incur an additional $241 in transition costs shown in the first row, second column of Table H9, which is the difference between the two configuration start-up costs. This unit cannot transition from configuration 2 to 4 so this transition path is not calculated. When the resource stays in configuration 1 it incurs only the start-up for configuration 1. After it transitions, it would only incrementally incur the transition cost to configuration 2. There are no transition costs from a higher to a lower configuration or if the resource stays in the same configuration. As a simplifying assumption, if each configuration has more than one segment, the highest priced segment will be used in the calculation.

<table>
<thead>
<tr>
<th>“From” configuration</th>
<th>“To” configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>UnitA_1</td>
<td>$241</td>
</tr>
<tr>
<td>UnitA_2</td>
<td>$16,265</td>
</tr>
<tr>
<td>UnitA_3</td>
<td>$16,024</td>
</tr>
<tr>
<td>UnitA_4</td>
<td>$241</td>
</tr>
</tbody>
</table>

If information is not provided for each configuration (even if the configuration is not startable), then the ISO will use data from the last available configuration. Refer back to Table H4 where data is missing for configurations 2 and 4. For data missing for configuration 2, the CAISO will use data from configuration 1 and for data missing for configuration 4 the CAISO will use data from configuration 3.

The consequence of not providing data for configurations 2 and 4 (and the CAISO using information from configurations 1 and 3, respectively), is a zero transition cost calculated for transition paths C1 to C2 and C3 to C4, reduced transition cost from C1 to C4, and an increase in transition cost from C2 to C3 because the C2 cost is now lower. Transitioning from C2 to C4 is not possible for this resource.
Table H10
Transition cost calculation for missing data: duct firing

<table>
<thead>
<tr>
<th>“From” configuration</th>
<th>“To” configuration</th>
<th>UnitA_1</th>
<th>UnitA_2</th>
<th>UnitA_3</th>
<th>UnitA_4</th>
</tr>
</thead>
<tbody>
<tr>
<td>UnitA_1</td>
<td></td>
<td>$0</td>
<td>$16,265</td>
<td>$16,265</td>
<td></td>
</tr>
<tr>
<td>UnitA_2</td>
<td></td>
<td></td>
<td>$16,265</td>
<td>n/a</td>
<td></td>
</tr>
<tr>
<td>UnitA_3</td>
<td></td>
<td></td>
<td></td>
<td>$0</td>
<td></td>
</tr>
<tr>
<td>UnitA_4</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Step 3: SC bids under proxy or registers transition costs under registered cost option

Transition costs are calculated under the same methodology as the MSG resource’s selected start-up cost option. Scheduling coordinators eligible for the registered cost option can register transition costs of up to 150 percent of projected transition costs. Scheduling coordinators under the proxy cost option can bid daily up to 125 percent of the calculated transition cost. A scheduling coordinator may not change its registered cost or change to proxy cost for a minimum 30-day period. The registered cost option has slightly different inputs to the proxy cost option as explained in Attachment G.

H.2 Examples: transition costs for non-natural-gas fired resources

The CAISO uses the same three step process to calculate costs for transition costs for non-natural gas resources (thermal and non-thermal). The major differences are the cost components. Modeling of non-natural gas-fired resources can follow the generic set-up of modular turbines or machines (e.g., pumps) or the relationship between combustion turbines and duct firing capacity.

For non-natural gas-fired resources (thermal and non-thermal), the CAISO system uses a single cost amount (in dollars) or a single cost amount per configuration (in dollars) in start-up costs instead of a heat input multiplied by the gas price. Other cost items remain largely the same except for different inputs used between the proxy and registered cost options as described in Attachment G.

EXAMPLE 3: NON-NATURAL GAS-FIRED RESOURCES WITH DISTINCT TURBINES

Step 1: SC data submission
Table H11 below shows an example of the cost items included for a resource, Unit C, with distinct engines. Unit C has four configurations. Only configurations 1 and 3 are directly startable and all transition paths are possible except from 2 to 4. In this example, a new configuration entails starting a new turbine (or generically a discrete machine). Therefore, most of the costs and physical parameters approximately double from the first to the second configuration. The CAISO expects that all the columns in yellow are verifiable costs and/or verifiable physical parameters of the resource. For example, the CAISO should be able to verify the heat input, start-up energy, configuration Pmin, and start-up time for each configuration. This resource has a greenhouse gas compliance obligation (or volunteered to be compliant). Each higher configuration should be presented as cumulative costs or amounts from the lower configurations.

The non-highlighted columns are costs that remain the same for all configurations and are provided by the CAISO, such as the greenhouse gas compliance cost.

<table>
<thead>
<tr>
<th>Config ID</th>
<th>Configuration</th>
<th>Non-nat gas start cost ($)</th>
<th>Heat input (MMBtu)</th>
<th>GHG price</th>
<th>GHG emission rate</th>
<th>Major maint. adder</th>
<th>Config Pmin</th>
<th>Config startup time (min)</th>
<th>GMC (MW)</th>
<th>Start-up energy (MWh)</th>
<th>Elec. price index ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UnitC_1</td>
<td>1 – Startable</td>
<td>$1,000</td>
<td>1,500</td>
<td>$12.00</td>
<td>0.0530752</td>
<td>10.000</td>
<td>200</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
</tr>
<tr>
<td>UnitC_2</td>
<td>2 – NOT startable</td>
<td>$2,000</td>
<td>2,300</td>
<td>$12.00</td>
<td>0.0530752</td>
<td>20.000</td>
<td>250</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
</tr>
<tr>
<td>UnitC_3</td>
<td>3 – Startable</td>
<td>$3,000</td>
<td>3,400</td>
<td>$12.00</td>
<td>0.0530752</td>
<td>35.000</td>
<td>400</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
</tr>
<tr>
<td>UnitC_4</td>
<td>4 – NOT startable</td>
<td>$4,000</td>
<td>4,400</td>
<td>$12.00</td>
<td>0.0530752</td>
<td>42.000</td>
<td>450</td>
<td>60</td>
<td>$0.38</td>
<td>20</td>
<td>$1.00</td>
</tr>
</tbody>
</table>

Table H11 assumes that the CAISO has enough information from the Scheduling Coordinator to calculate each start-up and indirect start-up cost. As noted above, if information is missing to calculate configuration level data (aside from the lowest configuration) the CAISO may use information from the next lowest configuration to backfill. Table H12 below provides an illustrative example where the data in yellow (for the startable configurations) has been provided but the data in orange (for the indirect start-ups) has not been provided but is instead copied from the next lowest configuration. As discussed in greater detail later, not providing data for certain start-up or indirect start-up costs may result in a lower or zero transition cost.

Table H12
Start-up and indirect start-up cost calculation for missing data: non-natural gas-fired turbine-based and thermal
Table H13 reproduces the same inputs as Table H11. The last column in blue calculates the total start-up or indirect start-up cost:

\[
\text{Start-up Cost} = (\text{Non-natural gas start cost}) + (\text{Start-Up Energy} \times \text{Energy Price Index}) + (\text{Pmin} \times \text{Start-Up Time Period in min} / 60 \text{ min/hour} \times \text{GMC adder} / 2) + (\text{Heat Input} \times \text{GHG Emission Rate} \times \text{GHG Allowance Price}) + \text{Major maintenance adder}
\]

Table H13 shows the calculated transition costs based on the start-up and indirect start-up costs shown in Table H13. The calculated transition costs are equal to 100 percent of transition costs. All of the transition costs are calculated as the difference between the “To” configuration and “From” configuration start-up and indirect start-up costs. For example, the start-up cost for configuration 1 is $12,104 and for configuration 2 is $23,533 as shown in the last column of
Table H13. If the resource transitions from configuration 1 to 2, it would incur an additional $11,429 in transition costs shown in the first row, second column of Table H9, which is the difference between the two configuration start-up costs. This unit cannot transition from configuration 2 to 4 so this transition path is not calculated. When the resource stays in configuration 1 it incurs only the start-up for configuration 1. After it transitions, it would only incrementally incur the transition cost to configuration 2. There are no transition costs from a higher to a lower configuration or if the resource stays in the same configuration. As a simplifying assumption, if each configuration has more than one segment, the highest priced segment will be used in the calculation.

Table H14
Transition cost calculation: non-natural gas-fired, turbine-based and thermal

<table>
<thead>
<tr>
<th>“From” configuration</th>
<th>“To” configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>UnitC_1</td>
</tr>
<tr>
<td>UnitC_1</td>
<td>$11,429</td>
</tr>
<tr>
<td>UnitC_2</td>
<td></td>
</tr>
<tr>
<td>UnitC_3</td>
<td></td>
</tr>
<tr>
<td>UnitC_4</td>
<td></td>
</tr>
</tbody>
</table>

Scheduling coordinators eligible for the registered cost option can register transition costs of up to 150 percent of calculated transition costs. A scheduling coordinator may not change its registered cost or change to proxy cost for a minimum 30-day period.

If information is not provided for each configuration (even if the configuration is not directly startable), then the ISO will use data from the last available configuration. Refer back to Table H12 where data is missing for configurations 2 and 4. For data missing for configuration 2, the CAISO will use data from configuration 1 and for data missing for configuration 4 the CAISO will use data from configuration 3.

The consequence of not providing data for configurations 2 and 4 (and the CAISO using information from configurations 1 and 3, respectively), is a zero transition cost calculated for transition paths C1 to C2 and C3 to C4, reduced transition cost from C1 to C4, and an increase in transition cost from C2 to C3 because the C2 cost is now lower. Transitioning from C2 to C4 is not possible for this resource.
Transition costs are calculated under the same methodology as the MSG resource’s selected start-up cost option. Scheduling coordinators eligible for the registered cost option can register transition costs of up to 150 percent of projected transition costs. Scheduling coordinators under the proxy cost option can bid daily up to 125 percent of the calculated transition cost. A scheduling coordinator may not change its registered cost or change to proxy cost for a minimum 30-day period. The registered cost option has slightly different inputs to the proxy cost option as explained in Attachment G.
Attachment I

CALCULATION OF GENERATED BIDS
I. Calculation of Generated Bids

This appendix is concerned solely with the calculation of the Generated Bid for non-Resource Specific System Resources. Unlike Generating Units and Resource Specific System Resources, which have physical characteristics which make it possible to calculate a cost based bid, a different approach must be used. Information on the use of these bids in the CAISO markets can be found in section 8.

I.1 Characteristics of the Generated Bid

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

Separate Generated Bids are calculated for the DAM and the RTM, as well as for peak and off-peak hours.

There are three methodology options for calculating Generated Bids:

- LMP Option: A weighted average LMP based on the lowest quartile of validated and/or corrected LMPs set at the at the Intertie point designated for the non-Resource-Specific System Resource during Trading Hours in the last 90 days when the resource was dispatched. These resources 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 Independent Entity.
- Price Taker Option: Equal to $0/MWh plus the CAISO’s estimate of the applicable grid management charge per MWh based on the gross amount of MWh scheduled in the DAM and RTM.
Each resource (through their SC) will select one of the three alternatives for Generated Bid calculation according to their preference for each resource. If the resource does not make a selection, the price taker option will be selected by default.

Note, if the LMP Option is selected, the resource must additionally select either the price-taker method or the negotiated-rate method as the alternative calculation method for the Generated Bids in the event that the feasibility test fails for the LMP-based method.

The details of the three alternatives are described below.

### I.2 LMP Option

If a Resource has selected the LMP option, the LMP option calculation method will be used to construct the Generated Bid to cover as much capacity as possible to the extent that the LMP option method is feasible. The Generated Bid for the remaining capacity will be constructed using either the negotiated rate option or the price taker 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 price taker option depending on which one is used.

Since the methodology for calculating the LMP-Based Generated Bid needs predefined segments and one of the other two methods as the fall back, the calculation will start with the second choice of the Resource, which could be either the price taker 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
- 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.

In the event that a resource fails the Feasibility Test, the second choice will be substituted for that particular segment. Finally, adjustments are made to ensure that the staircase bid curve is monotonically increasing.

#### I.2.1 Feasibility Test

The LMP option will not be available for the first ninety (90) days after a resource becomes a non-Resource- Specific System Resource. After the first 90 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 Generated Bid. This threshold number will set at a level that is designed to avoid excessive volatility of the LMP Generated Bid 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 Generated Bid 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).

I.2.2 Generated Bid Price Calculation

If a resource has passed the Eligibility Test and a Generated Bid segment has passed the Feasibility Test, the Generated Bid 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.

Monotonicity Adjustment

Right-To-Left Adjustment

The LMP-based Generated Bid must be monotonically increasing. The Right-To-Left Adjustment only applies to the LMP-based Generated Bid segments, i.e., not including the price taker or negotiated Generated Bid segments that have been substituted into the LMP-based Generated Bid curve. The Right-To-Left Adjustment will start from the right most LMP-based Generated Bid segment and ensure that the price of each valid LMP-based segment to the left is not greater than the price of the previous valid LMP-based segment to the right. Any segment that fails this test shall have its value reduced to the price of the next valid LMP-based segment to the right.

Left-To-Right Adjustment

The Left-To-Right Adjustment applies to all the Generated Bid segments, i.e., including the LMP-based Generated Bid, and the price taker Generated Bid segments or negotiated Generated Bid segments. The Left-To-Right Adjustment will start from the left-most bid 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.
I.3 Negotiated Rate Option

If the resource has selected the negotiated rate option, they shall follow the same procedure outlined for the negotiated rate option for Default Energy Bids in Appendix Attachment D.

I.4 Price Taker Option

The price taker option is based on the CAISO’s estimate of the applicable grid management charge per MWh.

Before the start of each year, the CAISO will take the estimated MWh GMC components from the Market Services and System Operations cost categories and use this value for the price taker option.
Attachment J

BIDDING ENFORCEMENT RULES FOR NON-RESOURCE SPECIFIC SYSTEM RESOURCES WITH RESOURCE ADEQUACY OBLIGATIONS
J. Bidding Enforcement Rules For Non-Resource Specific System Resources With Resource Adequacy Obligations

This appendix discusses the bidding enforcement rules in the Real-Time Market for non-Resource Specific System Resources that have Resource Adequacy (RA) obligations (NRS-RA resources). The bidding enforcement rules for these resources are different than for Generating Units. Day-Ahead enforcement rules are included for completeness.

J.1 Day-Ahead Bidding Enforcement Rules

In the Day-Ahead Market, an Energy Bid is required to cover the capacity specified by the RA obligation.

- When a NRS-RA resource does not provide an Energy Bid, a Generated Bid will be inserted on their behalf covering the RA obligation.

- When a NRS-RA resource provides an Energy Bid in the Real-Time Market, but does not cover the full RA obligation, their highest bid segment will be extended to cover the full RA obligation.

J.2 Real-Time Bidding Enforcement Rules

The main difference in the application of the bid enforcement rules for NRS-RA resources comes from the fact that System Resources do not participate in RUC, other than what is required under the RA obligation.

In real-time, an Energy Bid is required to cover the capacity specified by:

\[
\text{min}(\text{RA}, (\text{IFM schedule + any incremental RUC schedule}))
\]

The minimum of these two values is used because:

1) When the IFM + incremental RUC is greater than the RA obligation, the Real-Time requirement is limited to the RA obligation.

2) When the IFM + incremental RUC is less than the RA obligation, the Real-Time bidding requirement is limited to the Day – Ahead award.

The bid obligation is enforced as follows:
• When a NRS-RA resource does not provide an Energy Bid in the Real-Time Market, a Generated Bid will be inserted on their behalf covering the capacity specified by the equation above.

• When a NRS-RA resource provides an Energy Bid in the Real-Time Market, but does not cover the full capacity specified by the equation above, their highest bid segment will be extended to cover the full capacity.

J.3 Real-Time Bidding Enforcement Examples

These examples assume that a NRS-RA resource has a RA obligation of 100 MW.

Example 1: When IFM schedule = 120 MW, no incremental RUC
In this case, the enforcement is limited to the RA obligation. Therefore, only 100 MW will be enforced in real-time bidding.

Example 2: When IFM schedule = 80 MW, no incremental RUC
In this case, the enforcement is limited to the day-ahead schedule of 80 MW. Therefore, only 80 MW will be enforced in real-time bidding.

Example 3: When IFM schedule = 60 MW, incremental RUC of 20 MW
Total day-ahead schedule is 60 IFM + 20 incremental RUC = 80 MW. In this case, the enforcement is limited to the day-ahead schedule of 80 MW. Therefore, only 80 MW will be enforced in real-time bidding.
Attachment K

GREENHOUSE GAS ALLOWANCE INDEX
PRICE CALCULATION, CONTRIBUTION TO
COST-BASED CALCULATIONS, AND
EXAMPLES
K Greenhouse Gas Allowance Price Calculation, Cost-Based Bid Calculations, and Examples

K.1 Background

Starting in 2013 some of California’s thermal generating resources are subject to a greenhouse gas (GHG) allowance cap-and-trade system run under the authority of the California Air Resources Board. As such they bear per-MWh and per-startup costs associated with the purchase of GHG allowances needed to cover the GHG emissions associated with their energy output. The CAISO is including those costs in the cost-based calculations for minimum load and start-up costs, as well as default energy bids and generated bids.

This attachment contains:
1. The methodology used to calculate the daily index price used in certain cost-based bid components.
2. The methodology used to calculate the GHG component of start-up and minimum load costs, variable cost-based default energy bids, and generated bids
3. Sample calculations.

K.2 Greenhouse Gas Allowance Price

Resources subject to compliance with the California Air Resources Board (CARB) greenhouse gas cap regulations are responsible for submitting allowances for their emissions. CARB distributes these allowances through quarterly auctions and annual allocations and also directly allocates them to certain entities. CARB designates each allowance with a “vintage,” which is the calendar year the allowance is associated with. Compliance instruments from one compliance period can be held for sale or surrender in a future compliance period. For example, 2013 vintage allowances can be used for 2013 through 2015 compliance obligations.

California Greenhouse Gas Allowances are currently traded as futures products on commodity exchanges. There is the potential for development of spot market products or forward contracts to trade bilaterally in the over the counter market.

Index prices representing average trading prices are published by commercial providers each day. The CAISO or an independent entity selected by the CAISO shall procure these prices from up to three separate publications. The index price used by the CAISO for calculations, known as the Greenhouse Gas Allowance Price, shall be the average of values sourced from at least two providers.

The industry sources for greenhouse gas allowance trade prices have been identified as:
Based on the availability and timing of data from providers and the need to ensure accuracy, reliability and consistency the following principles have been established:

- The Greenhouse Gas Allowance Price should be an index calculated daily, not an index which averages across multiple trade days. This allows for a more accurate index.
- The ISO uses prices for the current year vintage greenhouse gas allowances. If the index uses prior year vintages, the ISO will use the prices that include the current year and past year vintages. For example, in 2014 the ISO would not use an index that includes 2015 and 2014 vintage greenhouse gas allowances, but would use an index that includes 2014 and 2013 vintage greenhouse gas allowances. This is appropriate because 2013 vintage greenhouse gas allowances can be used to meet 2014 compliance obligations and 2015 compliance obligations.

- If the price index lists greenhouse gas allowance prices based on futures or forwards prices, the ISO uses the price corresponding to a December delivery date.
- If the price index lists a range of prices, then the ISO uses the volume-weighted average price if available, alternatively, it uses the simple average price.
- At no stage will the number of source prices used fall below two. Should fewer than two current source prices be available the most recent Greenhouse Gas Allowance Price based on two or more source prices will be used.
- A prior Greenhouse Gas Allowance Price will also be used whenever a current Greenhouse Gas Allowance Price is unavailable for any reason.
- The Greenhouse Gas Allowance Price will be posted between 19:00 and 22:00 based on source prices representing trades occurring previously that day for the current year. In OASIS the price will be associated with the following day’s trading day. For example, the Greenhouse Gas Allowance Price for Trading Day (TD) January 23, 2013, will be based on source prices which are based on trades that occurred on January 22.
- Due to the publishing timing, the Greenhouse Gas Allowance Price associated with TD-1 will be used for the Day-Ahead market for any given TD. The Greenhouse Gas Allowance Price associated with TD will be used for the Real-Time market for any given TD. For example, for Real-Time markets running on January 23, 2013, the Greenhouse Gas Allowance Price used can be
K.3 Cost-Based Bid Calculations

The following calculations apply to both gas-fired and non-gas fired resources with a greenhouse gas compliance obligation.

In these calculations, emissions are described as equivalent carbon dioxide (CO$_{2e}$) indicating the global warming impact a given type and amount of greenhouse gas may cause, using the functionally equivalent amount or concentration of CO$_2$ as the reference.

K.3.1 Start-Up Costs

The cost of the greenhouse gas allowances shall be incorporated into the start-up costs as follows:

1. Calculate the greenhouse gas allowance start-up cost (one curve per resource, up to three segments) as a cost per start-up:

   CO$_{2e}$ emissions per start-up (mtCO$_{2e}$/start-up) * 1 (allowance/mtCO$_{2e}$) * Greenhouse Gas Allowance Price ($/allowance)

   Where:

   CO$_{2e}$ emissions per start-up (mtCO$_{2e}$/start-up) = unit’s start-up fuel requirement (mmBTU/start-up) * CO$_{2e}$ emission rate (mtCO$_{2e}$/mmBTU).

   Both the start-up fuel requirement and the CO$_{2e}$ emission rate is submitted by the SC in the Master File. This applies for both gas fired and non-gas fired resources with a greenhouse gas compliance obligation. The CO$_{2e}$ emission rate must be authorized by the California Air Resources Board.

2. For both gas fired and non-gas fired resources under the Proxy Cost Option, the CAISO calculates the cost in step 1 and includes it in the proxy start-up costs in accordance with Attachment G.2 of this BPM.

3. For resources that are eligible for and have elected the Registered Cost Option, the CAISO calculates the cost in step 1 and includes it in the projected proxy
start-up costs in accordance with Attachment G.1 of this BPM. The CAISO will not add a greenhouse gas cost to the start-up cost value registered in Master File. Instead, the Scheduling Coordinator of any such resources should incorporate greenhouse gas allowance costs into their registered start-up cost values.

K.3.2 Minimum Load Costs

The cost of the greenhouse gas allowances shall be incorporated into the Minimum Load Costs as follows:

1. Calculate the greenhouse gas allowance Minimum Load Cost (one value per resource) as a cost per MWh:

\[
\text{Average CO}_2\text{e emissions at minimum load (mtCO}_2\text{e/MWh) } \times 1 \times \text{(allowance/mtCO}_2\text{e)} \times \text{Greenhouse Gas Allowance Price ($/start-up)}
\]

Where:

\[
\text{Average CO}_2\text{e emissions at minimum load (mtCO}_2\text{e/MWh) = unit’s average heat rate at minimum load (mmBTU/MWh) } \times \text{CO}_2\text{e emission rate (mtCO}_2\text{e/mmBTU).}
\]

Both the average heat rate and CO\text{e} emission rate is submitted by the SC in the Master File. This applies for both gas fired and non-gas fired resources with a greenhouse gas compliance obligation. The CO\text{e} emission rate must be authorized by the California Air Resources Board.

2. Multiply this cost by the resource P\text{min} to obtain a cost in $/hr,

3. For both gas fired and non-gas fired resources under the Proxy Cost Option, the CAISO calculates the cost in steps 1 and 2 and includes it in the proxy minimum load costs in accordance with Attachment G.2 of this BPM.

4. For both gas fired and non-gas fired resources that are eligible for and have elected the Registered Cost Option, the CAISO calculates the cost in steps 1 and 2 and includes it in the projected proxy minimum load costs in accordance with Attachment G.1 of this BPM. The CAISO will not add a greenhouse gas cost to the minimum load cost value registered in Master File. Instead, the Scheduling Coordinator of any such resources should incorporate
greenhouse gas allowance costs into their registered minimum load cost values.

K.3.2 Default Energy Bids and Generated Bids

The cost of the greenhouse gas allowances shall be incorporated into default energy bids and generated bids as follows:

1. Calculate the greenhouse gas allowance incremental energy cost (one curve per resource, up to ten segments) as a cost per MWh:

\[
\text{Incremental CO}_2e \text{ emissions (mtCO}_2e/MWh) \times 1 \text{ (allowance/mtCO}_2e) \times \text{Greenhouse Gas Allowance Price ($/allowance)}
\]

Where:

\[
\text{Incremental CO}_2e \text{ emissions (mtCO}_2e/MWh) = \text{unit's incremental heat rate (mmBTU/MWh)} \times \text{CO}_2e \text{ emission rate (mtCO}_2e/mmBTU)}.
\]

The incremental heat rate is calculated from average heat rates submitted by the SC in the Master File, similar to the way the incremental heat rate is calculated in preparation of Default Energy Bids. See Appendix Attachment D for details on this calculation.

The CO\text{2}e emission rate is submitted by the SC in the Master File. The CO\text{2}e emission rate must be authorized by the California Air Resources Board.

2. For both gas fired and non-gas fired resources, the CAISO calculates the cost in step 1 and includes it in the generated bid curves and Default Energy Bids calculated using the Variable Cost Option and the Negotiated Rate Option (if negotiated by the Scheduling Coordinator). For gas-fired resources, the greenhouse gas allowance cost is included in the incremental energy cost calculated by the CAISO in accordance with Attachment D of this BPM. For non-gas fired resources, the greenhouse gas allowance cost is added to the average cost submitted by the Scheduling Coordinator in Master File.

3. The resulting curve is subject to monotonicity (left-to-right) adjustments.
K.4 Examples

K.4.1 Start-Up Costs

Let's consider a resource with one start-up cost segment with the following data:

<table>
<thead>
<tr>
<th>Startup fuel requirement:</th>
<th>1,083 mmBTU/start-up</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂e emission rate:</td>
<td>0.053165 mtCO₂e/mmBTU</td>
</tr>
<tr>
<td>Greenhouse Gas Allowance Price :</td>
<td>$15.70 /allowance</td>
</tr>
</tbody>
</table>

CO₂e emissions per startup = start-up fuel requirement * CO₂e emission rate = 1083 * 0.053165 = 57.57769 mtCO₂e/start-up.

Greenhouse gas allowance start-up cost = CO₂e emissions per start-up * 1 * Greenhouse Gas Allowance Price = 57.57769 * 1 * $15.70 = $903.97 / start-up.

$903.97 would be added to start-up costs if calculated using the Proxy Cost Option.

This example applies to both gas-fired and non-gas-fired resources with a greenhouse gas compliance obligations under this Option.

K.4.2 Minimum Load Costs

Let's consider a resource with the following data:

<table>
<thead>
<tr>
<th>Average heat rate at minimum load:</th>
<th>7.840 mmBTU/MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resource Pmin</td>
<td>160 MW</td>
</tr>
<tr>
<td>CO₂e emission rate:</td>
<td>0.053165 mtCO₂e/mmBTU</td>
</tr>
<tr>
<td>Greenhouse Gas Allowance Price :</td>
<td>$15.70 /allowance</td>
</tr>
</tbody>
</table>

Average CO₂e emissions at minimum load = unit’s average heat rate at minimum load * CO₂e emission rate = 7.840 * 0.053165 = 0.41681 mtCO₂e/MWh.

Greenhouse gas allowance minimum load cost = Average CO₂e emissions at minimum load * 1 * Greenhouse Gas Allowance Price = 0.41681 * 1 * $15.70 = $6.54 /mWHR.

Greenhouse gas allowance MLC converted to $/hr = MLC in $/MWh * MW at Pmin = $6.54 * 160 = $1046.40

$1046.40 would be added to the minimum load costs if calculated using the Proxy Cost Option.
This example applies to both gas-fired and non-gas-fired resources with a greenhouse gas compliance obligations under this Option.

K.4.3 Default Energy Bids and Generated Bids

Let's consider the resource in example 1 of Attachment F with the following incremental heat rates:

<table>
<thead>
<tr>
<th>Operating Point (n)</th>
<th>Operating Level (MW)</th>
<th>Segment</th>
<th>Adjusted Incremental Heat Rate (BTU/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>164</td>
<td>1</td>
<td>7292</td>
</tr>
<tr>
<td>2</td>
<td>298</td>
<td>2</td>
<td>7643</td>
</tr>
<tr>
<td>3</td>
<td>340</td>
<td>3</td>
<td>5438</td>
</tr>
<tr>
<td>4</td>
<td>480</td>
<td>4</td>
<td>9601</td>
</tr>
<tr>
<td>5</td>
<td>590</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

And let's use the same GHG data from previous examples:

<table>
<thead>
<tr>
<th>CO₂e emission rate:</th>
<th>0.053165 mtCO₂e/mmBTU</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greenhouse Gas Allowance Price :</td>
<td>$15.70 /allowance</td>
</tr>
</tbody>
</table>

The first segment would be calculated as follows. Note the incremental heat rate needs to be divided by 1000 to convert from BTU/kWh to mmBTU/MWh.

Incremental CO₂e emissions = unit’s incremental heat rate * CO₂e emission rate = 7292 * 0.053165 / 1000 = 0.38768 mtCO₂e/MWh.

Greenhouse gas allowance incremental energy cost = Incremental CO₂e emissions * 1 * Greenhouse Gas Allowance Price = 0.38768 * $15.70 = $6.09 /MWh

The same method is used to calculate costs for the other segments, with the following results:

<table>
<thead>
<tr>
<th>Segment</th>
<th>Operating Range</th>
<th>Adjusted Incremental Heat Rate</th>
<th>GHG Incremental Cost</th>
<th>GHG Cost After Left-to-Right Adj</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>164-297</td>
<td>7292</td>
<td>$6.09</td>
<td>$6.09</td>
</tr>
<tr>
<td>2</td>
<td>298-339</td>
<td>7643</td>
<td>$6.38</td>
<td>$6.38</td>
</tr>
<tr>
<td>3</td>
<td>340-479</td>
<td>5438</td>
<td>$4.54</td>
<td>$6.38</td>
</tr>
</tbody>
</table>
These greenhouse gas allowance incremental costs will then be added to the incremental costs described in step 3 of example 1 of Attachment F, before applying the left-to-right adjustments:
Attachment L

MAJOR MAINTENANCE COST ADDERS
L. Major Maintenance Cost Adders

L.1 Introduction

In a competitive market, suppliers will submit offers at prices that reflect the marginal costs of supplying the product, i.e., the incremental costs of supplying the product. Therefore, market rules in wholesale electricity markets designed to mitigate market power must allow generators to reflect all costs that are marginal to the decision to start and run generating units. Certain types of “major maintenance” costs are incurred infrequently and may appear to be fixed costs (and not marginal costs). However, the frequency is directly correlated with starting the unit and/or running the unit for a period of time after the unit has started. Therefore, the major maintenance costs are marginal costs with respect to starting or running the unit.

For example, a unit that should undergo a major overhaul after a specified number of starts or run-hours would rationally cause the supplier to consider these costs in its decision to start and run the unit. Depending upon how the incurrence of the major maintenance expense is affected by each of these factors, the marginal cost components associated with major maintenance may be accurately quantified in a $ per run-hour and/or a $ per start adder.

The purpose of this Attachment L is to describe the process for gathering the necessary information and producing marginal cost adders to reflect major maintenance for each generating unit.

L.2 Data Collection

First, the CAISO or an Independent Entity acting as an agent for the CAISO collects major maintenance expense data from market participants through a standard template for each unit (the link is provided at the end of this section). The template is spreadsheet-based (or otherwise based on a standard application or platform) with validation to ensure it is completed properly.

The template contains a section allowing market participants to list major maintenance actions grouped into distinct maintenance cycles. For each maintenance cycle, market participants should list the following data as applicable:

- Criteria. The three options for this include 1) a single parameter (e.g. every 10,000 run hours), 2) the earlier of multiple parameters (e.g. energy 10,000 run hour or 100 starts) or 3) a blend of multiple parameters (e.g. equivalent operating hours)
- A description of the primary factor or factors and equivalency between factors if applicable.

For each maintenance action listed, the market participant should identify the following:

- Maintenance cycle.
- Maintenance action name and description.
- A cost estimate. This cost estimate may be either an historic value or an estimated future value. In either case, the cost should be reported with the year in which the cost is denominated so that values may be adjusted to the current year.
- Incremental operating hours and/or starts as relevant. This value represents the estimated incremental number of run hours and/or starts at which this maintenance action is performed. For example, if an action is performed every 10 starts, the incremental contribution of this component of the MMA would be calculated by dividing the estimated cost of this action (denominated in current year dollars), by 10.
- Documentation reference. Market participants should provide a documentation reference for each maintenance action. This reference indicates the source of the maintenance action cost and estimated incremental operating hours and/or starts. The CAISO, or its agent, may request the source documentation in cases where costs appear anomalous.

There are two cases in which the CAISO anticipates that scheduling coordinators may not be able to provide the information requested in the maintenance actions schedule. The first is a case in which major maintenance costs are performed under a long-term service agreement (LTSA). The second is a case in which the resource is tolled to a scheduling coordinator under a power purchase agreement (PPA). In either of these cases, market participants should provide the maintenance cycle data supplemented by the following data entered in the Scheduling Coordinator Estimates section of the template:

- An estimate of the cost per start and/or run hour.
- An explanation of the derivation of the cost estimate.
- Documentation reference. Market participants should provide a documentation reference for each estimated cost. This reference indicates the source of the cost and estimated incremental operating hours and/or starts. The CAISO, or its agent, may request the source documentation in order to verify and review the accuracy and reasonableness of the reported or estimated costs.

All submitted applications should also contain the following descriptive information for each resource: contact information, resource identification including resource characteristics such as manufacturer make and model, in service date and capacity.
The information submitted is then reviewed by comparison to the historic experience for the unit and by comparing it to other similar units based on technology, size, and age.

For a resource whose major maintenance is conducted under an LTSA or PPA, the CAISO evaluates the consistency of the costs with the applicable LTSA or PPA and determines whether these costs are reasonable based on actual and estimated major maintenance costs for similar resources.

Finally, for each cost item and schedule, the CAISO or its agent translates cost into real present-day dollars and uses this cost to calculate the individual components of the major maintenance cost adders.

The template is located at:

http://www.caiso.com/Documents/MajorMaintenanceTemplate.xlsx

L.3 Produce Major Maintenance Cost Adders

The operating parameter to which major maintenance is assigned depends on the maintenance schedule and the operating profile of the resource. Maintenance schedules can vary significantly, which affects how the adders would be produced. This is illustrated in the following figure, which shows two types of maintenance schedules. The first schedule shown by the blue square is an example of where major maintenance is needed based on a maximum number of starts or a maximum number of run-hours, whichever comes first (referred in the figure as the “Or” criteria). Alternatively, some manufacturers recommend major maintenance based on the number of starts and run-hours where each start is equivalent to a certain number of run-hours (i.e., the Equivalent Operating Hour (EOH) method). This is shown by the green line in the figure.

Figure L1 – Effects on major maintenance due to maintenance criteria and resource type
Or Criteria

Under the Or criteria, the start criteria or the run-hour criteria may be binding for a unit depending on its average run-hours per start. The three red lines in the figure represent three types of units. The units have different operating profiles and, therefore, intersect the Or criteria at very different locations. For example, the top line shows a peaking resource that typically has a low number of run-hours per start (because its incremental energy costs are relatively high). For the peaking resource, the maintenance intervals are determined only based on the number of starts, so the maintenance adders should be applied to the starts. The starts are limiting for peaking resources because the failure mechanisms that are expected to limit the life of the equipment are based on thermal cyclic fatigue, which leads to crack propagation in hot gas path parts. Each start creates an additional thermal cycle.

However, for baseload resources (i.e., resources for which run-hours per start are large), the maintenance intervals are primarily determined based on the run-hours, so the maintenance adders should primarily be applied to the run-hours. The run-hours are limiting for baseload resources because the failure mechanisms that are expected to limit the life of the equipment are based on the run-time-dependent conditions of creep, oxidation, and corrosion.

In some cases, the distribution of the maintenance adders based on the operating profile could cause the operating profile to change. For example, for a unit has been operating with a relatively low level of run-hours per start (like the peaking resource above), shifting the allocation of the adders from run-hours to the start-up cost will raise the unit’s start-up cost and lower its minimum generation cost, which will tend to increase the unit’s average run-
hours per start. This could shift the operating profile toward the line shown in Figure 1 for the intermediate unit. The advantage of this shift is that it will increase the utilization of the unit under the major maintenance schedule.

If the allocation of the maintenance adders is seen to affect the operating profile of the resource, it is rational to divide the adders between the starts and the run-hours and adjust the allocation on an ongoing basis based on the operating data for the resource.

**EOH Criteria**

Under the EOH criteria, the adders would be divided between start-up cost and minimum generation cost in the same ratio as the EOH criteria. For example, if one start is equivalent to 20 run-hours, the major maintenance cost would be divided by the total run-hour in the maintenance cycle to establish the minimum generation cost adder while the Start-Up-Cost adder would equal the minimum generation adder times 20.

**Start-Up Costs**

A resulting Start-Up Cost adder will be calculated ($/start). The same value will be applied to the three start segments, i.e., the same adder will apply for hot, warm, and cold starts. For MSG Resources a separate adder will be calculated for each start-able configuration. Depending on the criteria used, the resulting Start-Up Cost adder may be zero.

If a resource has no major maintenance costs, the Start-Up Cost adder will be zero.

**Minimum Load Costs**

A resulting Minimum Load Cost adder will be calculated ($/hr) and applied to the resource. For MSG resources, a separate adder will be calculated for each configuration. Depending on the criteria used, the resulting Minimum Load Cost adder may be zero.

If a resource has no major maintenance costs, the Minimum Load Cost adder will be zero.

**L.4 Updates**

Depending on the starts and run-hours per year, a unit would typically have time between major maintenance intervals ranging from one to four or more years. Over these years, the trajectory of run-hours per start will likely vary by season given a constant set of maintenance adders. For example, a unit is likely to have a longer average number of run-hours per start in the summer than in the spring.

For cost elements that are incurred based on the Or criteria, the CAISO or its agent will develop expected operating profiles and compare the actual operating data with these expectations to determine whether each resource’s major maintenance costs should be allocated to starts or minimum generation. Because the operating profile may change over time, for cost elements that are incurred based on the Or criteria, the allocation of the
adders between starts and minimum generation may be updated to reflect long term changes in a units operating profile.

Additionally, market participants may contact the CAISO or its agent when a significant issue arises that may change the amount or allocation of the major maintenance cost adders. These could include the expiration of an LTSA or significant changes in the physical condition of the generator that affects the major maintenance costs or schedule. Updates to the template may be made every 30 days. See Section L.2 for the location of template.

L.5 Major Maintenance Adders

The CAISO will add major maintenance values to the Start-Up and Minimum Load Costs calculated under the Proxy Cost Option. In addition, the CAISO will use the adders in the calculation of the monthly proxy costs for determining the maximum Start-Up and Minimum Load Costs allowed under the Registered Cost Option. See Attachment G for details.

L.6 Possible scenarios leading to renegotiation of Major Maintenance Adders

All major maintenance adders (MMA) approved 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 applied for a MMA with the CAISO. An MMA will be reviewed and potentially renegotiated or terminated under the following circumstances:

1. Change in scheduling coordinator
   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
   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 Pmin/Pmax changes
   d. resource or a configuration within a multi-stage generator retires
   e. resource changes generation technology type in Master File

3. Change in major maintenance costs
   a. conditions underlying resources' original major maintenance adder application are no longer applicable or accurate
4. Change in any other material item which might affect the approved major maintenance adder.

It is the responsibility of the scheduling coordinator to ensure that the conditions and data underlying any major maintenance adder for a resource accurately reflect current conditions and to notify the CAISO of any changes that may affect their major maintenance adder. To the extent that any major maintenance adder for the resource or multi-stage generator configurations require modification or reinstatement after termination, the corresponding scheduling coordinator for the resource should submit an updated MMA application to the CAISO to avoid the risk of invalid MMA's when changes occur either at the resource level or at the scheduling coordinator level. Until a new MMA has been established, a temporary MMA may be negotiated between the scheduling coordinator and the CAISO.
Attachment M

EPI: Electricity Price Index Calculation
M  Electricity Price Index

M.1  Introduction

As provided in tariff section 30.4.1.1, the proxy start-up cost includes the cost of auxiliary power calculated as the MWh quantity of auxiliary power used to start the resource multiplied by a resource-specific electricity price. This component is calculated for all generating resources.\(^{33}\) The cost is calculated as the product of the electricity required for start-up (as registered in Master File) and the electricity price index (EPI). The purpose of this appendix is to describe the calculation of the resource-specific EPI.

The EPI for EIM resources is calculated using the formula used for CAISO resources choosing the registered cost option. This formula is described in section G.1.1 of the Market Instruments BPM as an estimated electricity price calculated by multiplying the projected monthly future gas price multiplied by a factor of 10.

For CAISO resources, the EPI is calculated daily for each resource as the maximum of a retail rate and an estimated wholesale rate. Each is described in further detail below.

M.2  Retail Electricity Price

Each resource is mapped to the retail electricity provider according to the fuel region assigned to the generator’s pricing node. The EPI is a daily value. The retail price on any day including a peak hour, as defined below, is assigned a peak retail price. All days without a peak hour are assigned an off-peak price. The electricity price for each retail provider is updated semi-monthly, on the 5th business day and the last business day of each month, from the sources listed below:

**PG&E:**

PG&E Standby Service Rate Transmission Voltage. This is sourced from ‘Electric Schedule S Standby Service\(^{34}\), Total Energy Rates ($ per kWh) under Transmission Voltage. Select appropriate season and peak status from the following as defined in the schedule:

**SUMMER (May 1 through October 31):**

- Peak: 12:00 noon to 6:00 p.m. Monday through Friday (except holidays)
- Partial-Peak: 8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays)

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\(^{33}\) The inclusion of auxiliary power costs is explicit in section 30.4.1.1.1 (gas fired resources). If non gas fired resources can demonstrate that they have such costs, then they can also recover auxiliary power costs.

• Off-Peak: 9:30 p.m. to 8:30 a.m. Monday through Friday All Day
  Saturday, Sunday, and holidays

WINTER (November 1 through April 30):
• Partial-Peak: 8:30 a.m. to 9:30 p.m. Monday through Friday (except holidays)

• Off-Peak: 9:30 p.m. to 8:30 a.m. Monday through Friday (except holidays)
  All Day Saturday, Sunday and holidays

SCE:
The Southern California Edison Standby Service Rate is sourced from Schedule TOU-8-RBU time of use general service large reliability back up service for service metered and delivered at voltages above 50kv Generation UG. Select appropriate season and peak status from the following as defined in the schedule:

SUMMER (June 1 through September 30):
• Peak: 12:00 noon to 6:00 p.m. Monday through Friday (except holidays)
• Mid-Peak: 8:00 a.m. to 12:00 noon AND 6:00 p.m. to 11:00 p.m. Monday through Friday (except holidays)
• Off-Peak: 11:00 p.m. to 8:00 a.m. Monday through Friday All Day Saturday, Sunday and holidays

WINTER (October 1 through May 31):
• Mid-Peak: 8:00 a.m. to 9:00 p.m. Monday through Friday (except holidays)
• Off-Peak: 9:00 p.m. to 8:00 a.m. Monday through Friday (except holidays)
  All Day Saturday, Sunday and holidays

SDG&E: resources located in SDG1 and SDG2 fuel areas are assigned SCE rates.
CAISO: resources located in the CISO fuel region will be assigned the minimum retail rate

M.3 Wholesale Electricity Price

The wholesale electricity price for each resource is the projected real-time electricity price at the resource node calculated using the algorithm described below.

First, a forward electricity-adjusted price is created for each pricing node and hour. Then, hours are categorized as summer on-peak, summer off-peak, winter-peak, or winter off-peak. In the

final step, adjusted prices for the relevant season and peak status category are averaged to produce a projected wholesale price for the resource.

**Forward Electricity-Adjusted Prices**

The forward electricity-adjusted price calculation relies on the following data inputs:

1. **Historic real-time prices (LMP):** Price-corrected LMPs from the five-minute real-time market are collected for each interval for the 12 prior months prior to the month of the calculation date. These values are then averaged to create an hourly real-time price for each hour.

2. **Forward Electricity Price Index (EF):** Forward electricity price data are sourced from the DMR IFED Futures for Day-Ahead Peak and Off-Peak Fixed Price Futures. NP-15 prices are used for PGE1 and PGE2; SP-15 prices are used for all other regions. The indices used for NP-15 are NPM and ONP for peak and off-peak futures, respectively. The indices for SP-15 are SPM and OFP for peak and off-peak futures, respectively.

The forward electricity-adjusted prices are then calculated as follows:

1. Categorize real-time price data as on-peak or off-peak for comparison to electricity forwards. For this purpose, hours are categorized as follows:
   - Peak - non-holiday weekdays from hour end 7 to 22
   - Off-Peak - All remaining hours

2. Calculate market-wide average monthly peak and off-peak historic real-time electricity price. This simple average equally weights all pricing nodes to approximate the historical market-wide energy price.

3. Calculate a monthly forward conversion factor for each region in the 12 prior months by dividing the forward electricity price for the same month of the next year by the average price in the historic month. This ratio is bounded between 1 and 1.5. Therefore if the forward electricity price is less than the historic electricity price, the conversion factor is set equal to one.

4. Multiply the historical LMP at each generator location by the monthly forward conversion factor applicable to the relevant fuel region, month and hour category. Resources located in the CISO fuel region will receive a forward conversion factor that is set to the minimum across fuel regions within CAISO in each month. The forward electricity-adjusted prices are recalculated monthly.

**Wholesale Hour Categorization:**

Hourly adjusted prices are then re-categorized into three distinct time periods of summer on-peak, winter on-peak and off-peak subject to the following conditions:
- Summer and winter off-peak retail rate hours on weekends and holidays\(^{36}\) are combined together and classified as off-peak.
- Summer on-peak hours map to non-holiday weekdays between June and September from hour end 7 to 22. Resources in the PG&E fuel region receive summer rates from May through October.
- Winter on-peak hours map to non-holiday weekdays between November and April from hour end 7 to 22. Resources in SCE and SDG&E fuel regions receive winter rates for May and October.
- For resources in the CISO region, the definition of summer and winter period shall be consistent with PG&E.
- Only the 8 highest-priced on-peak hours (as defined by the market-wide simple average calculated in step 2 above) on a given day are included in the summer and winter on-peak calculations. This condition limits on-peak hours to a maximum of 40 hours per week when unit starts are most frequent.

**Average Wholesale Energy Price Index Calculation:**

Adjusted LMPs are then averaged within each of the three season and period categories. The resultant averages at each pricing node are the seasonal wholesale prices for on-peak summer and winter days. The off-peak result is mapped to both summer off-peak and winter off-peak categories for combination with the retail prices in M.4.

**M.4 Resource-specific EPI Calculation**

EPI values are evaluated daily as the maximum of the retail price and the estimated wholesale price in the relevant category. If sufficient data is not available to calculate a wholesale EPI, the EPI shall be set to the retail rate until such time as sufficient data is available to calculate a wholesale EPI. As described above, summer includes all months between June and September. Additionally, resources in PG&E fuel regions receive summer rates for May and October in accordance with the season definitions in the PG&E Electric Schedule S. The remaining months are classified as winter months. If the market day contains any peak hours, the day is considered an on-peak day. All remaining days are considered off-peak.

\(^{36}\) Off-peak hours on non-holiday weekdays are excluded since the EPI is a daily value and non-holiday weekdays are classified as peak days.
Addendum to Market Instruments BPM
(Based on Ver. 39)
A Addendum for changes

Due to Aliso Canyon phase 2 gas-electric coordination initiative and the interim tariff revisions from December 1st, 2016 through November 30, 2017. This Addendum will address the modification to Version 39 of the Market Instruments BPM as follows:

<table>
<thead>
<tr>
<th>Number</th>
<th>Feature</th>
<th>Tariff Section Numbers</th>
<th>Effective Date</th>
<th>BPM section</th>
<th>Existing section in MO BPM</th>
<th>Modified section in MO BPM</th>
<th>Expiration Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Make two-day ahead advisory schedules available with the clarification that they are not financially binding or operationally binding</td>
<td>6.5.2.2.3</td>
<td>6/2/2016</td>
<td>10 &amp; 12</td>
<td>See below</td>
<td>See below</td>
<td>November 30, 2017</td>
</tr>
<tr>
<td>2</td>
<td>Use current gas price information to increase efficiency of economic dispatch</td>
<td>6.5.2.3.4, 30.4.1.2, 39.7.1.1.1.3 (a)(b)(c), 31.6.1, and deleting old (b)</td>
<td>7/6/2016</td>
<td>Attachment C</td>
<td>See below</td>
<td>See below</td>
<td>November 30, 2017</td>
</tr>
<tr>
<td>3</td>
<td>Adjust the gas price indexes used to calculate commitment and default energy bids &amp; generated bids for affected resources on the SoCalGas/SDG&amp;E system</td>
<td>39.7.1.1.1.3 (d)</td>
<td>7/6/2016</td>
<td>Attachment C</td>
<td>See below</td>
<td>See below</td>
<td>November 30, 2017</td>
</tr>
<tr>
<td>4</td>
<td>Permit market participants to rebid commitment costs in the real-time market</td>
<td>30.5.1(b)</td>
<td>6/2/2016</td>
<td>4.1, 5.1.1.1.1, 5.1.1.1.2, 8.2.1.3, B.2.1, G.2.1.1, G2.1.2</td>
<td>See below</td>
<td>See below</td>
<td>November 30, 2017</td>
</tr>
</tbody>
</table>
6. Introduce a constraint as needed into the CAISO’s market processes to limit the affected gas area burn to a maximum or minimum

<table>
<thead>
<tr>
<th>Date</th>
<th>Attachment</th>
<th>See</th>
<th>See</th>
<th>November 30, 2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>27.11</td>
<td>new</td>
<td>below</td>
<td>below</td>
<td></td>
</tr>
<tr>
<td>6/2/2016</td>
<td>Attachment</td>
<td></td>
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</tr>
</tbody>
</table>

**Number 1**

**A10.1 Scope of CMRI Reports available to SCs**

Exhibit 10-1.1 summarizes the reports that are available to SCs through the Customer Market Results Interface (CMRI). Details of the report contents are provided in subsequent sections.

<table>
<thead>
<tr>
<th>Title</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day-Ahead Generation Market Results</td>
<td>Day-Ahead Energy Schedules, Ancillary Services Awards, Load Following and RUC Capacity for Generating Units</td>
</tr>
<tr>
<td>Day-Ahead Demand Market Results</td>
<td>Day-Ahead Energy Schedules and Ancillary Services Awards of Participating Loads and Day-Ahead Energy Schedules for Non-Participating Loads</td>
</tr>
</tbody>
</table>
| Day-Ahead Residual Unit Commitment (RUC) Capacity | RUC Capacity and RUC Awards from the Residual Unit Commitment process. Posted hourly, the following values:  
  - Capacity (total RUC capacity) - this is the positive difference between the RUC Schedule and the greater of the Day-Ahead |

<table>
<thead>
<tr>
<th>Exhibit 0-1.1: Summary of CMRI Reports</th>
<th></th>
</tr>
</thead>
</table>

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<table>
<thead>
<tr>
<th>Title</th>
<th>Contents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Schedule and the Minimum Load level of a resource.</td>
<td></td>
</tr>
<tr>
<td>• Award (RUC Award portion) – this is the portion of the RUC</td>
<td></td>
</tr>
<tr>
<td>capacity from resources eligible to receive RUC Availability Payments.</td>
<td></td>
</tr>
<tr>
<td>• For Interties the total RUC Schedule is displayed as the RUC Award</td>
<td></td>
</tr>
<tr>
<td>product.</td>
<td></td>
</tr>
<tr>
<td>Two Day-Ahead Residual Unit Commitment (RUC) Advisory Schedules</td>
<td>This report is based on the Two Day-Ahead process run. For the second trading day, the resource level advisory RUC Schedule is the Schedule in MW which gets cleared from the RUC process. While it is advisory, it serves as a forecast of the resource’s upcoming energy schedule on a two-day ahead base. RUC data presented in this report is for informational purposes only. This advisory data will be available for a rolling window of seven trading-date period on CMRI as soon as the Two Day-Ahead process run is completed (14:00 and 18:00 PST).</td>
</tr>
<tr>
<td>Day-Ahead Import/Export Schedules</td>
<td>Day-Ahead Energy Schedules and Ancillary Services Awards at Intertie Scheduling Points.</td>
</tr>
<tr>
<td></td>
<td>Addition of a new column called “Effective Intertie”, an element that only applies to intertie resources. In cases of an open-tie situation per market run results, this element will indicate the Secondary Tie identifier; whereas if there is no open-tie situation, this element will indicate the Primary Tie identifier.</td>
</tr>
<tr>
<td>Day-Ahead Start-Up Instructions</td>
<td>Start-Up instructions resulting from the RUC process</td>
</tr>
<tr>
<td>Day-Ahead Ancillary Service Market Results</td>
<td>Resource-specific Ancillary Service Awards resulting from the Integrated Forward Market run</td>
</tr>
<tr>
<td>Day-Ahead Market Power Mitigation (MPM) Results</td>
<td>Segments of the “new” or mitigated Bid as a result of the Day-Ahead Market Power Mitigation Process (MPM)</td>
</tr>
<tr>
<td>HASP Market Power Mitigation (MPM) Results</td>
<td>Segments of the “new” or mitigated Bid as a result of the HASP Market Power Mitigation Process (MPM)</td>
</tr>
<tr>
<td>FMM Market Power Mitigation (MPM) Results</td>
<td>Segments of the “new” or mitigated Bid as a result of the FMM Market Power Mitigation Process (MPM)</td>
</tr>
<tr>
<td>Default Energy Bid Curves</td>
<td>Default Bid Curve data used in the Market Power Mitigation process. The Default Energy bids for the real time market will be based on an energy scaling factor applied to the commodity price only for the SCE and SDGE regions. For the day-ahead market, the default energy bids will be updated prior to the start of the day-ahead market to reflect the most current commodity price using the ICE index.</td>
</tr>
<tr>
<td>Day-Ahead Generation Commodity Prices</td>
<td>Day-Ahead resource-specific prices (for Energy Schedules, Ancillary Services Awards, RUC Awards) of Generating Units</td>
</tr>
<tr>
<td>Day-Ahead Demand Commodity Prices</td>
<td>Day-Ahead resource-specific prices for Energy Schedules and Ancillary Services Awards of Participating Loads; and resource-specific prices for Energy Schedules of Non-Participating Loads</td>
</tr>
<tr>
<td>Hour Ahead Scheduling Process (HASP) Schedules</td>
<td>Displays Hour-Ahead Scheduling Process results for the next Trading Hour. Posts the HASP Binding results relevant to hourly HASP Block</td>
</tr>
<tr>
<td>Title</td>
<td>Contents</td>
</tr>
<tr>
<td>-------</td>
<td>----------</td>
</tr>
<tr>
<td>Intertie Schedules. Posts HASP Advisory results relevant to all other Pre-Dispatch Resources.</td>
<td>Displays Hour-Ahead Scheduling Process advisory resource-specific prices for the next Trading Hour.</td>
</tr>
<tr>
<td>Hour Ahead Scheduling Process (HASP) Schedule Prices</td>
<td>Displays FMM results for the next 15-minute interval. FMM schedules cover real-time Energy and Ancillary Services Awards. Addition of a new column called “Effective Intertie”, an element that only applies to intertie resources. In cases of an open-tie situation per market run results, this element will indicate the Secondary Tie identifier; whereas if there is no open-tie situation, this element will indicate the Primary Tie identifier. Addition of a new product commodity – code “IEEA”; with a display value of “CA Export Allocation”. This is the Imbalance Energy Export Allocation applicable for EIM resources.</td>
</tr>
<tr>
<td>Fifteen-Minute Market (FMM) Schedules</td>
<td>Displays FMM resource-specific prices for the next 15-minute interval. Covers prices for Energy and Ancillary Services Awards. Addition of a new Locational Marginal Price LMP component called “GHG” Greenhouse Gas only applicable for EIM resources. It is the additional LMP component due to the net energy export allocation constraint.</td>
</tr>
<tr>
<td>Fifteen-Minute Market (FMM) Schedule Prices</td>
<td>Day-Ahead Finally Qualified Load Following Up and Down Capacity for Metered Subsystems (MSS) resources</td>
</tr>
<tr>
<td>Day-Ahead Finally Qualified Load Following Capacity</td>
<td>Resources that are self-committed or CAISO committed by the IFM or RUC process in the Day-Ahead Market</td>
</tr>
<tr>
<td>Day-Ahead Unit Commitments</td>
<td>Displays the default minimum load and startup cost bid curves that will used for the Market Power Mitigation (MPM) Process. This information originates from an independent entity and applies to RMR units only.</td>
</tr>
<tr>
<td>Default RMR Minimum Load &amp; Startup Cost Bid Curves</td>
<td>Day-Ahead resource-specific prices (for Energy Schedules, Ancillary Services Awards, RUC Awards) of System Resources</td>
</tr>
<tr>
<td>Day-Ahead Import-Export Commodity Prices</td>
<td>Startup instructions resulting from the Extremely Long Start Commitment (ELC) process. This report is not currently active.</td>
</tr>
<tr>
<td>Extremely Long Start Resource Startup Instructions</td>
<td>RMR units that either have an Energy Schedule (from the IFM run) that is flagged as an RMR Dispatch and/or a Manual RMR Dispatch</td>
</tr>
<tr>
<td>Day-Ahead Reliability Must Run (RMR) Dispatches</td>
<td>Displays the post-market Expected Energy results from the energy Accounting process. Expected Energy is the sum total of all DA and RT (including FMM and RTD) market awards, Exceptional Dispatches and any other Dispatch Instructions, taking into account physical limitations (outage management system), disaggregated into their Settlement components. For residual energy, report includes the price at which the residual energy will be settled.</td>
</tr>
<tr>
<td>Expected Energy Allocation Details</td>
<td>Day-Ahead resource-specific prices for Energy Schedules, Ancillary Services Awards, RUC Awards of System Resources</td>
</tr>
<tr>
<td>Title</td>
<td>Contents</td>
</tr>
<tr>
<td>----------------------------------------------------------------------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
</tbody>
</table>
| User may choose to display allocation either by Default Energy Bid, or the final input bid used by the market systems (SIBR clean bid as adjusted by market pre-processors). Addition of two new expected energy type codes applicable for EIM resources:  
  • BASE - real-time expected energy based on the base schedules  
  • MDE - manual dispatch energy signals |                                                                                                                                                                                                             |
<p>| Conformed Dispatch Notice (CDN)                                      | Summary of the Day-Ahead and Real-Time Energy Schedules, Ancillary Service Awards, RMR Dispatches, Competitive Constraint Run results of RMR resources                                                                 |
| Expected Energy                                                      | Post-market or after-the-fact energy accounting results for Settlement calculations. This report will contain the Total Expected Energy for Day Ahead, Fifteen-Minute, and Real Time Dispatch, and include Instructed and Total energy. |
| ISO Commitment Cost Details                                          | Includes Commitment and transition Flags, time periods and Costs to validate the Bid Cost Recovery charge in Settlements                                                                                                                                             |
| Non-Dispatchable Time Ranges                                         | Specifies the start and end time of non-dispatchable periods including resource commitments, transitions, operations within a forbidden region and DOP corrections. Used to validate the Bid Cost Recovery charge in Settlements. |
| CRN                                                                  | Reports the MW breakdown and CRN number market results for ETC/TOR Self-Schedules in the DAM and the RTM. These MWs breakdown are inputs used in the ETC/TOR balancing rights, and are not the final ETC/TOR balancing rights. RTM CRN reporting includes ETC/TOR schedule changes after the close of the RTM. Note: This report has limited functionality, and is only available in the GUI. The same results are posted to the CAISO SFTP site for downloading. Access to the CRN data through the SFTP site is managed through the AARF (Application Account Request Form) process. |
| Fifteen-Minute Market (FMM) Flexible Ramping Constraint Capacity     | Reports the amount of upward ramping MW quantity of Flexible Ramping Constraint capacity awarded for each resource.                                                                                                                                                  |
| Resource-Specific VER Forecast Usage                                 | Posts the actual 5-minute and 15-minute load forecast used by RTM, Depending on option chosen by the SC and forecast availability, forecast may come from either the values submitted by the SC or from the forecast generated by CAISO systems. Posts for all intervals (binding and advisory) in the FMM and RTD run time horizon. |
| Real-Time Dispatch (RTD) Schedules                                  | Reports the 5-minute interval based resource level binding energy schedules from the real-time 5-minute market runs.                                                                                                                                                |
| Real-Time Dispatch (RTD) Advisory Schedules                         | Reports the 5-minute interval based resource level advisory energy schedules from the real-time 5-minute market horizon                                                                                                                                             |
| Real-Time Dispatch (RTD) Schedule Prices                            | Reports the 5-minute interval based resource level binding prices from the real-time 5-minute market runs.                                                                                                                                                       |</p>
<table>
<thead>
<tr>
<th>Title</th>
<th>Contents</th>
</tr>
</thead>
</table>
| Intertie Resource Transaction ID | Reports all of the unique alphanumeric identifiers, that were dynamically generated by the bidding system (SiBR) referred to as the “Transaction ID”; and its corresponding attributes:  
  • RegisteredInterTie identifier  
  • SchedulingCoordinator identifier  
  • PrimaryFlow gate identifier  
  • SecondaryFlow gate identifier  
  • AggregatedPnode identifier  
  • IndividualPnode identifier  
  • Direction (Import, Export)  
  • Energy Product Type (Firm Energy, Non Firm Energy, Dynamic Interchange, Wheeling, Unit Contingency)  
  • Purchase Service Entity (PSE)  
  • Wheeling Resource identifier  
  • Wheeling Resource registeredFlag |
| Day-Ahead Base Schedules      | Reports the generation and interchange base schedules submitted for the day-ahead and/or real-time markets to the CAISO. These represent the forward energy schedules, with hourly granularity that is the baseline to measure deviations for settlement through the EIM. |
| Real-Time Base Schedules      | Reports the generation and interchange base schedules submitted for the day-ahead and/or real-time markets to the CAISO. These represent the forward energy schedules, with hourly granularity that is the baseline to measure deviations for settlement through the EIM. |
| Base Schedules                | Reports the generation and interchange EIM Base Schedules submitted for the day-ahead and/or real-time markets to the CAISO. These represent the forward energy schedules, with hourly granularity that is the baseline to measure deviations for settlement through the EIM. |
| EIM Transfer                  | Reports the Energy Imbalance Market transfer (mw) breakdown for each EIM Entity Balancing Authority Area and EIM Entity Balancing Authority Area group under the real-time market runs (RTPD and RTD). |
| Load Base Schedules           | Reports the base schedules for load resources under the real-time markets                                                                                                                                 |
| Balancing Test Results        | Report that provide the results for the series of tests conducted to ensure that each EIM Entity Balancing Authority Area has sufficient resources to serve its load while still realizing the benefits of increased resource diversity. Please refer to the *Energy Imbalance Market Business Practice Manual* document for more information. |
| Transmission Violation Test Results | Report that provide the results for the series of tests conducted to ensure that each EIM Entity Balancing Authority Area has sufficient resources to serve its load while still realizing the benefits of increased resource diversity. Please refer to the *Energy Imbalance Market Business Practice Manual* document for more information. |
| Flexible Ramp Requirement     | Report that provide the results for the series of tests conducted to ensure that each EIM Entity Balancing Authority Area has sufficient resources to serve its load while still realizing the benefits of increased resource diversity. Please refer to the *Energy Imbalance Market Business Practice Manual* document for more information. |
### Title | Contents
---|---
Sufficiency Test Results | resources to serve its load while still realizing the benefits of increased resource diversity. Please refer to the *Energy Imbalance Market Business Practice Manual* document for more information.

Bid Range Capacity Test Results | Report that provide the results for the series of tests conducted to ensure that each EIM Entity Balancing Authority Area has sufficient resources to serve its load while still realizing the benefits of increased resource diversity. Please refer to the *Energy Imbalance Market Business Practice Manual* document for more information.

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### Convergence Bidding Reports

The following four Convergence Bidding reports are available through the Customer Market Results Interface (CMRI).

Reports 4.2, 4.3 and 4.4 are associated with the CRR Adjustment Settlement Rule. For additional details on the CRR Adjustment Settlement Rule, please see the BPM for Market Operations, Appendix F.

- **Day Ahead Convergence Bidding Awards**
  Displays the market Virtual Bidding supply and demand awards that were cleared in the day-ahead market for energy Addition of a new column called “Intertie”, which defines the “Primary Tie” if the virtual bid Pnode or Apnode is external to CAISO

- **Hourly Prices due to Convergence Bidding for CRR Adjustment**
  Displays the hourly prices that CAISO uses to calculate Congestion Revenue Rights (CRR) adjustments due to Virtual Bidding.

- **Binding Transmission Constraints due to Convergence Bidding for CRR Adjustment Report**
  Displays supporting data for settlement charges imposed on scheduling coordinators, as a result of the application of the CRR settlement rule - specifically CRR flow impact on award locations for each scheduling coordinator.

- **Flow Impact due to Convergence Bidding for CRR Adjustment**
  Displays supporting data for settlement charges imposed on scheduling coordinators, as a result of the application of the CRR settlement rule – specifically CRR flow impact aggregated by Entity, where the Entity is a Convergence Bidding Entity name that coincides with a CRR Holder.

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### A12.9 Prices

CAISO provides information on prices to the public through the OASIS web page. The Price reports contain the following information:

- **Locational Marginal Prices (LMP)** – Posts Hourly Locational Marginal Prices for all PNodes, APNodes and Scheduling Points in $/MWh, for the DAM and RUC market processes. Data fields are as follows:
  
  - LMP
• LMP Marginal Cost of Energy (MCE)
• LMP Marginal Cost of Congestion (MCC)
• LMP Marginal Cost of Losses (MCL)

➢ Note: For the RUC prices, only the RUC price is posted. The three-component LMP breakdown is not applicable for RUC pricing.

➢ HASP Locational Marginal Prices (LMP) – Posts hourly, the 4 15-minute advisory Locational Marginal Prices in $/MWh, for the HASP hour. Posts the LMP, plus the Congestion, Loss and Energy Components that make up the LMP.

➢ Note: In the event of HASP failure, HASP Pnode prices may not be available in OASIS. In this case, CAISO will not backfill these advisory prices.

➢ Data fields are as follows:

➢ LMP

  • LMP Marginal Cost of Energy (MCE)
  • LMP Marginal Cost of Congestion (MCC)
  • LMP Marginal Cost of Losses (MCL)

➢ FMM Locational Marginal Prices (LMP) – Posts on a 15-minute basis, the 15-minute financially binding Locational Marginal Prices in $/MWh, for the FMM market process. Posts the LMP, plus the Congestion, Loss and Energy Components that make up the LMP.

➢ Interval Locational Marginal Prices (LMP) – Posts the five-minute Locational Marginal Prices for PNodes and APNodes in $/MWh, for each five-minute interval Real-Time Economic Dispatch (RTED). Data fields are as follows:

➢ LMP

  • LMP Marginal Cost of Energy (MCE)
  • LMP Marginal Cost of Congestion (MCC)
  • LMP Marginal Cost of Losses (MCL)
• Greenhouse Gas (GHG) 37

- **Contingency Dispatch Locational Marginal Prices (LMP)** – Similar to the Interval Locational Marginal Prices (LMP) report, but for Real Time Contingency Dispatch (RTCD) runs.
  
  - Posts the ten-minute Locational Marginal Prices for PNodes and APNodes in $/MWh, for each ten-minute interval RTCD. Data fields are as follows:
    
    - LMP
      
      • LMP Marginal Cost of Energy (MCE)
      
      • LMP Marginal Cost of Congestion (MCC)
      
      • LMP Marginal Cost of Losses (MCL)

- **EIM Green House Gas Shadow Prices (GHG)** - Provides the Greenhouse Gas Shadow Price of the net imbalance energy export from all EIM Entity BAAs imported into the ISO BAA resulting from the Real-Time Market runs (RTPD and RTD).

- **AS Clearing Prices** – Posts the Ancillary Services Marginal Price (ASMP) for all Ancillary Service types for all binding AS Regions. Posted hourly in $/MW for the DAM.
  
  - DAM - Hourly ASMP ($/MW)

- **Interval AS Clearing Prices - Ancillary** Services Marginal Price (ASMP) for all Ancillary Service types for all binding AS Regions. Posts 15-Minute price relevant to the next 15 minute binding interval for RTM on a fifteen minute basis.
  
  - RTM - 15Min Binding ASMP ($/MW)

- **Intertie Constraint Shadow Prices** – Posts the hourly constraint pricing at each Intertie-based Transmission Interface And Intertie Constraint, for each Market Process (DAM, HASP) in $/MWh, and the 15-Minute Shadow Price in $/MWh for the FMM. Report will also include an indication of whether the Constraints were binding because of the

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37 Greenhouse Gas component is only applicable to the Energy Imbalance Market (EIM)
base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

- **Nomogram/Branch Shadow Prices** – Posts the hourly constraint pricing at each binding Nomogram and Branch, for each Market Process (DAM, HASP) in $/MWh, and the 15-Minute Shadow Price in $/MWh for the FMM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

- **Fuel Prices** – For each Gas Flow Day, lists the gas price in $/MMBTU by fuel region. This report shows the fuel prices applicable for the real-time market. The fuel prices applicable for the day-ahead market are not published. For the regions belonging to SCE and SDG fuel regions, the fuel prices will include a commitment scaling factor in the commodity price.

- **Current Locational Marginal Price** – This report is available for download only. Five minute Locational Marginal Prices for all PNodes and APNodes for the current interval. (Returns the most recently posted interval only) This download is provided to allow Oasis users to quickly receive the most current LMP without any prior intervals included in the payload.

- **Interval Intertie Constraint Shadow Prices** – Posts the 5-Minute constraint pricing at Transmission Interfaces and Intertie Constraints in $/MWh, for the RTD run in the RTM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

- **Contingency Dispatch Intertie Constraint Shadow Prices** – Similar to the Interval Intertie Constraint Shadow Prices report, but for Real Time Contingency Dispatch (RTCD) runs. Posts the 10-Minute constraint pricing at Transmission Interfaces and Intertie Constraints in $/MWh, for the RTCD run in the RTM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

- **Interval Nomogram/Branch Shadow Prices** - Posts the 5-Minute constraint pricing at each Nomogram and Branch in $/MWh, for the RTD run in the RTM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

- **Contingency Dispatch Nomogram/Branch Shadow Prices** - Similar to the Interval Nomogram/Branch Shadow Prices report, but for Real Time Contingency Dispatch (RTCD) runs. Posts the 10-Minute constraint pricing at each Nomogram and Branch in $/MWh, for
the RTCD run in the RTM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

- **Reference Prices** – Posts Quarterly Reference prices associated with each Virtual Bidding PNode and APNode for supply and demand.

- **Nodal Group Constraints Shadow Prices** – This report displays the upper and lower MW limits, cleared MW value and associated hourly shadow prices for any binding Nodal Group Constraint. This report is triggered with the publication of the Day-Ahead results.

- **Flexible Ramping Constraint Results** – Posts the following values for RTUC and RTD market runs, for intervals when the Flexible Ramping Constraint is enforced.

  - **Ramp Up Capacity (MW)** - The required amount of total un-loaded capacity below maximum operating limits (that can be dispatched up) of the ramp-limited resources that is retained through the market optimization. The Flexible Ramping Constraint is enforced on a system level per market run and market interval.

  - **Ramp Up Shadow Price ($/MW)** - Shadow price of the ramping up constraint when binding in the relevant market run and in the binding market interval. Binding interval shadow price is the Ramp Up Shadow Price.

  - Payment to resources providing the flexi-ramp capacity will be paid based on the following price: For each applicable fifteen-minute FMM interval, the Flexible Ramping Constraint derived price will be equal to the lesser of: 1) $800/MWh; or 2) the greater of: (a) 0; (b) the Real-time Ancillary Services Marginal Price for Spinning Reserves for the applicable fifteen-minute FMM interval; or (c) the Flexible Ramping Constraint Shadow Price minus seventy-five percent of the maximum of (i) zero (0); or (ii) the Real-Time System Marginal Energy Cost, calculated as the simple average of the three five-minute Dispatch Interval System Marginal Energy Costs in the applicable fifteen-minute FMM interval.

  - The flexi-ramp cost for each binding FMM interval can be estimated by the amount of procured RAMP Up Capacity multiplied by the price described above in that binding interval. If the flexi-ramping constraint is binding and feasible, the procured Ramp Up Capacity is equal to the flexi-ramping capacity requirement (Ramp Up Capacity or RAMP_UP_CAP_REQ). However, if the flexi-ramping constraint is infeasible, meaning that the FMM market run is unable to procure the full required flexi-ramping capacity, the procured Ramp Up Capacity would be less than the flexi-ramping capacity requirement. On OASIS, the flexi-ramping capacity requirement not the procured amount is posted.
- **MPM DA Locational Marginal Prices (LMP)** – Hourly Locational Marginal Prices from the Day-Ahead MPM run for all PNodes and APNodes associated with market resources with physical bids in $/MWh. Posts the LMP, including the competitive congestion component, non-competitive congestion component, loss and energy components that make up the LMP.

- **MPM RTM Locational Marginal Prices (LMP)** – 15-minute Locational Marginal Prices from the HASP and FMM MPM runs for all PNodes and APNodes associated with market resources with physical bids in $/MWh. Posts hourly for the 4 intervals of the HASP hour and every 15 minutes for FMM. Posts the LMP, plus the competitive congestion component, non-competitive congestion component, loss and energy components that make up the LMP.

- **MPM Nomogram/Branch Group Shadow Prices** – Posts the constraint pricing at each binding nomogram and branch group, for each market process of the MPM run (DAM, HASP, FMM) in $/MWh. Posts hourly data for DAM and 15 minute data for HASP and FMM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

- **MPM Nomogram/Branch Group Competitive Paths** – Posts the results of the dynamic competitive path determination, for binding nomogram and branch constraints for each market process of the MPM run (DAM, HASP, FMM). Posts hourly data for DAM and 15 minute data for HASP and FMM. Posts a flag indicating whether each binding constraint was competitive or not.

- **MPM Intertie Constraint Shadow Prices** – Posts the constraint pricing at Transmission Interfaces and Intertie Constraints, for each market process of the MPM run (DAM, HASP, FMM) in $/MWh. Posts hourly data for DAM and 15 minute data for HASP and FMM. Report will also include an indication of whether the Constraints were binding because of the base operating conditions or contingencies, and if caused by a Contingency, the identity of the specific Contingency.

- **MPM Intertie Constraint Competitive Paths** – Posts the results of the dynamic competitiveness constraint, for binding interchange, market scheduling limit, and branch group constraints for each market process of the MPM run (DAM, HASP, FMM). Posts hourly data for DAM and 15 minute data for HASP and FMM. Posts a flag indicating whether each binding constraint was competitive or not.
- **MPM Reference Bus** – Posts the reference bus used in the MPM run for each market process of the MPM run (DAM, HASP, FMM). Contains hourly data for the Day-Ahead market and 15-minute data for HASP and FMM. Note, the IFM, RUC, and regular HASP and FMM runs use a distributed reference bus.

- **Greenhouse Gas Allowance Prices** – Posts the index price for the greenhouse gas allowance in $/allowance.

  Historical ACE Data – Pursuant to FERC Order 784; 18 C.F.R § 385 37.6(k), the CAISO will post on OASIS historical one-minute and ten-minute area control error data for the most recent calendar year, and update this posting once per year. The CAISO will post this annual data by the end of January for the previous year.

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**Attachment C**

**GAS PRICE INDEX CALCULATION RULES**

**AC Gas Price Index Calculation Rules**

**AC.1 Background**

The daily Gas Price Index (GPI) is the index that is used in the calculation of the Default Energy Bids, as well as the generated bids including Startup Costs, and Minimum Load Costs subject to the proxy cost option. The GPI has a number of key components, including principally the gas price indices themselves and the intra-state gas transport costs. Gas Price Indices consist of a single price ($/mmBTU) for each GPI Region, of which there is at least one for each of the main LSEs. Each Resource is associated with the GPI Region in which it resides, or to which it is geographically closest. The GPI calculated for resources assigned to a BAA regional fuel region (e.g., CISO) will be the minimum of all GPI index values for GPI Regions within the BAA. Monthly futures gas prices are used in the calculation of Demand Response net benefits test (DR NBT) threshold prices and projected proxy costs. The monthly price is calculated similar to the daily price, but using an average of several days' futures prices instead of a single day-ahead price.
AC.2  Gas Transport Cost

The proxy gas transport costs are based on the cost of gas transport in the respective service territories of the main LSEs. It is calculated in the following manner:

- Units served by SDG&E: The Southern California Gas Company intrastate transportation rate (currently GT-SD) plus the volumetric component of the SDG&E gas transportation rate for electric generation service, including the ITCS38 (currently GTUEG – SD), or any successor rate for electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.

- Units served by Southern California Gas: The Southern California Gas Company intrastate transportation rate for firm electric generation service, including the ITCS39 (GT-F) plus the G-ITC Wheeler Ridge Interconnection Access fee, if applicable, or any successor rate for firm electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.

- Units served by PG&E: The PG&E intrastate transportation charge stated in Rate Schedule G-EG, or any successor rate for electric generation service applicable to deliveries to the Facility, divided by one minus the applicable in-kind shrinkage allowance, if any.39

AC.3  Daily Gas Prices

Pursuant to tariff section 30.4 and 39.7.1.1.1.3, the CAISO will use different gas prices for the Day-Ahead Market and the Real-Time Market. Gas price index will be calculated for both the day-ahead and real-time markets for the following fuel regions:

<table>
<thead>
<tr>
<th>Gas Price Index hubs</th>
<th>Gas Price Index plus applicable regional transportation adder</th>
</tr>
</thead>
<tbody>
<tr>
<td>PG&amp;E Citygate</td>
<td>PGE2</td>
</tr>
<tr>
<td>SoCal Citygate</td>
<td>SCE1</td>
</tr>
</tbody>
</table>

38 ITCS means Interstate Transition Cost Surcharges.

39 If the Facility does not qualify for service under Rate Schedule G-EG, the applicable rate shall be given by Rate Schedule G-NT.
The specific calculations for day-ahead and real-time are different and are described in sections C.3.1 for day-ahead and C.3.2 for real-time.

**AC.3.1  Standard Calculation Process for the Day-Ahead Market**

For the Day-Ahead Market, the CAISO will use the gas price reported by the Intercontinental Exchange between 8:00 and 9:00 Pacific Time. The CAISO will use a volume-weighted average price calculated by the Intercontinental Exchange based on the trades transacted for next-day gas for the PG&E Citygate and Southern California (SoCal) Citygate hub prices.

The CAISO then adds the appropriate transportation adder to create five specific different regional gas cost values, plus one region for CAISO (outlined in section C.1 above), utilized in the CAISO market systems.

If for any reasons the ICE price is not available by 9am, the day ahead market will use the gas price indices estimated through the real-time market process described in section C.3.2.

**AC.3.2  Standard Calculation Process for the Real-Time Market**

For the Real-time market, the CAISO will use at least two prices from two or more of the following publications: Natural Gas Intelligence, SNL Energy/BTU’s Daily Gas Wire, Platt’s Gas Daily, and the Intercontinental Exchange. The gas price indices reflect the commodity gas price.

If for any reason there are fewer than two available gas price indices, the real-market will use the last available gas price indices.

<table>
<thead>
<tr>
<th>Source</th>
<th>Earliest Time Available (PST)</th>
<th>Latest Time Available (PST)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ICE</td>
<td>11:30 AM</td>
<td>12:00 PM</td>
</tr>
<tr>
<td>SNL Energy/BTU Daily</td>
<td>16:00 PM</td>
<td>19:00 PM</td>
</tr>
<tr>
<td>NGI</td>
<td>19:00 PM</td>
<td>2:00 AM (flow date)</td>
</tr>
<tr>
<td>Platt’s</td>
<td>17:00 PM</td>
<td>19:00 PM</td>
</tr>
</tbody>
</table>
The CAISO calculates the Real-Time Market gas price indices each day between 19:00 and 22:00 Pacific Time using natural gas prices published earlier on the same day.

**AC.3.2.1 Real-Time Market Gas Price Index for Southern California**

Due to limited operations of the Aliso Canyon natural gas storage facility, the CAISO will increase the gas price for resources receiving gas service from Southern California Gas Company and San Diego Gas and Electric Company based on gas and electric system conditions. This will improve the dispatch of these resources so that they are more likely to be dispatched to address local needs rather than system needs, account for the systematic differences between day-ahead and same-day natural gas prices and improves the ability to manage the generators’ gas usage within applicable gas balancing rules. Applicable resources are gas-fired resources that have registered SCE1, SCE2, SDG1 or SDG2 as the fuel region for the resource in the Master File.

For applicable resources, the CAISO will increase the gas commodity used in the calculation of Start-Up Costs, Minimum Load Costs and Transition Costs as described in Tariff Section 30.4.1.1 by a scalar value. The CAISO will set this value at an amount that is consistent with system conditions and with Section 39.7.1.1.1.3(d): 75%.

- Improves the dispatch of these resources so that they are more likely to be dispatched to address local needs rather than system needs.
- Better accounts for systematic differences between day-ahead and same-day natural gas prices.
- Improves the ability to manage the generators’ gas usage within applicable gas balancing rules.

**Tariff Section 39.7.1.1.1.3(d) allows for increases and decreases in the scalar percentages.**

For example, if the commitment scalar for a given trade date is 75%, the adjustment will be as follows:

Gas Price Index for Southern California Commitment Costs = SoCal Citygate commodity price * 1.75 + applicable Transportation Cost

**Similarly, for applicable resources, the CAISO will increase the gas commodity used in the calculation of variable cost Default Energy Bids as described in Tariff Section 39.7.1.1 by a scalar value 25%.**

For example, if the scalar for bids for a given trade date is 25%;
Gas Price Index for Southern California Default Energy Bids = SoCal Citygate commodity price *1.25 + applicable Transportation Cost

The CAISO will issue a Market Notice specifying the amount of both scalars that are in effect as soon as practicable and prior to the close of the bid submission of the applicable Real-Time Market Tariff Section 39.7.1.1.3(d) allows for increases and decreases in the percentages. The CAISO will issue a Market Notice specifying the amount of the increase or decrease.
Bid components are divided into two categories:

- **Daily Bid components** – These Bid components are constant across all Trading Hours in a Trading Day and do not change for that Trading Day, except for Start-Up, Minimum Load and Transition Costs which can be re-bid in RTM.

- **Hourly Bid components** – These Bid components can vary in each Trading Hour of the Trading Day.

With the exception of three Bid components (Start-Up, Minimum Load and Transition Costs), all Bid components can vary each day, and are submitted by SCs as part of their DAM and RTM Bids. For Start-Up and Minimum Load Bid components, the SC selects one of two alternatives: Registered Cost or Proxy Cost. The elections are independent; that is, a Scheduling Coordinator electing either the Proxy Cost option or Registered Cost option for Start-Up Costs may make a different election for Minimum Load Costs. The Start-Up and Minimum Load Bid components are constant for each Trading Day for the period submitted.

If Registered Cost is selected for Start-Up and/ or Minimum Load, the SC submits information for Start-Up and/ or Minimum Load respectively to CAISO for entry into the Master File. Subject to the applicable cap, these values can be updated every 30 days through the Master File Update process that is described in Attachment B. Start-Up and Minimum Load Costs under the Registered Cost Option may not exceed 150 percent of the unit’s Projected Proxy Cost for Start-Up and Minimum Load Costs. If the SC selects the Registered Cost Option, the values will be fixed for 30 days unless the resources costs, as calculated pursuant to the Proxy Cost option, exceed the Registered Cost option, in which case the SC may switch to the Proxy Cost option for the balance of the 30 day period. (see Attachment G for details).

If the Proxy Cost option is selected, the Start-Up and Minimum Load Bid components are calculated daily for each Generating Unit based on the daily gas price and includes, in addition, auxiliary power costs (for Start-Up), O&M costs (Minimum Load adder as listed in Exhibit 4-2, the adder is a value registered in the Master File), greenhouse gas allowance Start-Up and
Minimum Load costs if applicable (see Attachment K), the Market Services Charge and System Operations Charge components of the Grid Management Charge (GMC) (for Start-Up), the Market Services Charge and System Operations Charge components of the GMC and the Bid Segment Fee component (for Minimum Load), and a major maintenance cost adder if applicable (see Attachment L), which may be different for Start-Up and Minimum Load. The process that CAISO uses to calculate the daily gas price is shown in Attachment C, and there is an example in section 8.2.1.3 for a Generated Bid. The SC is also allowed to submit a Start-Up and/or Minimum Load Cost Bid as part of a generator’s Bid in the Day-Ahead Market (DAM) and or the Real-Time Market (RTM) as long as the SC elected the Proxy Cost option for them and the submitted Bid is not negative and is less than or equal to the proxy cost calculated using the daily Gas Price Index and the Relative Proxy (Start-up or Minimum Load) Cost Ceiling. RTM submissions will not be used if the resources was committed in the DAM, the DAM Daily Components will be copied to the RTM bid.

Transition Cost will be calculated as the product of the Transition Fuel and the Daily Gas Price Index associated with the resource. This will be the same for all Multi-Stage Generating Resources regardless of the resource’s elected Cost option.

The details of the Bid components are described in subsequent sections.

### Exhibit 0-1: Daily & Hourly Bid Components

<table>
<thead>
<tr>
<th></th>
<th>Daily Components</th>
<th>Hourly Components</th>
<th>Submitted through SIBR</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start-Up</td>
<td>![Checkmark]</td>
<td></td>
<td>Yes, only if proxy cost option is currently effective for Start-Up Cost in Master File.</td>
<td>If the resource has elected to use Registered Cost, the Start-Up cost used is that registered in the Master File. If the resource has elected the Proxy Cost option, the SC can submit a Start-Up Cost through SIBR in either DAM or RTM. SIBR would use the submitted Start-up cost if it is not negative and is less than or equal to the Start-Up Cost calculated based on daily gas prices.</td>
</tr>
<tr>
<td>Minimum Load</td>
<td>![Checkmark]</td>
<td></td>
<td>Yes, only if Proxy Cost option is currently</td>
<td>If the resource has elected to use Registered Cost, the Minimum Load cost</td>
</tr>
<tr>
<td>Daily Components</td>
<td>Hourly Components</td>
<td>Submitted through SIBR</td>
<td>Comment</td>
<td></td>
</tr>
<tr>
<td>------------------</td>
<td>-------------------</td>
<td>------------------------</td>
<td>---------</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>effective for Minimum Load Cost in Master File.</strong></td>
<td>used is that registered in the Master File. If the resource has elected the Proxy Cost option, the SC can submit a Minimum Load Cost through SIBR in either DAM or RTM. SIBR would use the submitted Minimum Load Cost if it is not negative and is less than or equal to the Minimum Load is calculated based on gas daily prices.</td>
<td></td>
</tr>
</tbody>
</table>

Transition Costs  
Yes, these values are calculated as defined in Attachment H, based on the calculated start-up costs for each configuration  
For a Multi-Stage Generating Resources, the dollar cost per feasible transition associated with moving from one online configuration to another. SC can submit Transition Cost through SIBR in either DAM or RTM. The calculation is the same for all MSG regardless of the Cost option.

Energy Bid Curve  
Self-Schedule  
Ancillary Services  
Regulation Down  
Regulation Up  
Spinning Reserve  
Non-Spinning Reserve  
Ramp Rate  

Bid cannot contain more than certified quantities for each service.

Bid by SC, within limits of the minimum and maximum Ramp Rates in the Master File.
<table>
<thead>
<tr>
<th></th>
<th>Daily Components</th>
<th>Hourly Components</th>
<th>Submitted through SIBR</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operational Ramp Rate</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Operating Reserve Ramp Rate</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Regulation Ramp Rate</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Contingency Dispatch Indicator</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td>Must be selected if any AS is part of the Bid/Schedule.</td>
</tr>
<tr>
<td>Intertie Minimum Hourly Block (DA)</td>
<td>✓</td>
<td>✓</td>
<td>✓</td>
<td>For Non-Dynamic System Resources, specifies minimum number of hours that an intertie bid must be awarded in the DA market, if economic. If no Minimum Hourly Block is set, it defaults to 1.</td>
</tr>
</tbody>
</table>
| Dispatch Option                |                  | ✓                | ✓                      | A Bid option that determines the participation of an Intertie resource in the Real-Time Market:  
  - Hourly: submission of a HASP Block Intertie Schedules  
  - Once: submission of an Economic Hourly Block Bid with Intra-Hour option.  
  - 15min: dispatched in each 15 minute Interval of a Trading Hour with a flat Dispatch for all 5 minute Dispatch Intervals of that 15 minute Interval. Dynamic: dispatched |
<table>
<thead>
<tr>
<th>Component</th>
<th>Daily Components</th>
<th>Hourly Components</th>
<th>Submitted through SIBR</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pump Shut-Down Cost</td>
<td></td>
<td>✓</td>
<td>✓</td>
<td>in each 5 minute Dispatch Interval of a Trading Hour.</td>
</tr>
<tr>
<td>Pumping Cost</td>
<td></td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Energy Limit (Maximum and Minimum Daily)</td>
<td>✓</td>
<td></td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>RUC</td>
<td></td>
<td>✓</td>
<td>✓</td>
<td></td>
</tr>
<tr>
<td>Capacity Limit</td>
<td></td>
<td>✓</td>
<td>✓</td>
<td>(Unrelated to Capacity Limit Indicator). Specifies an upward limit on the total Energy and Ancillary Services awards for a given hour. Limit must be set no lower than the maximum of the highest energy bid or the RA obligation amount. Used mainly for partial RA or non-RA resources who want to limit the total award when bidding multiple services.</td>
</tr>
<tr>
<td>Distribution Factors</td>
<td></td>
<td>✓</td>
<td>✓</td>
<td>These apply to Generating Units only. Generation Distribution Factors are provided on a per-unit basis. SC may submit through SIBR. If none are provided through SIBR, CAISO will use Generation Distribution Factors (GDF) from the GDF Library based on historical generation pattern.</td>
</tr>
</tbody>
</table>
VER Forecast

If a Variable Energy Resource (VER) chooses to supply an energy forecast, the forecast shall be submitted through SIBR. Forecast is submitted for a configurable rolling time horizon as often as every 5 minutes.

**Exhibit 0-2: Default O&M Cost Adders effective April 1, 2012 ($/MWh)**

<table>
<thead>
<tr>
<th>Generation Technology</th>
<th>Recommended VOM Cost Adder ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar</td>
<td>$0.00</td>
</tr>
<tr>
<td>Nuclear</td>
<td>$1.00</td>
</tr>
<tr>
<td>Coal</td>
<td>$2.00</td>
</tr>
<tr>
<td>Wind</td>
<td>$2.00</td>
</tr>
<tr>
<td>Hydro</td>
<td>$2.50</td>
</tr>
<tr>
<td>Combined Cycle and Steam</td>
<td>$2.80</td>
</tr>
<tr>
<td>Geothermal</td>
<td>$3.00</td>
</tr>
<tr>
<td>Landfill Gas</td>
<td>$4.00</td>
</tr>
<tr>
<td>Combustion Turbine &amp; Reciprocating Engine</td>
<td>$4.80</td>
</tr>
<tr>
<td>Biomass</td>
<td>$5.00</td>
</tr>
</tbody>
</table>

**A5.1.1.1 Start-Up Component**

This Bid component applies only to Generating Units (and to Dynamic and Non-Dynamic Resource-Specific System Resources, Proxy Demand Resources, and Reliability Demand Response Resources, which are modeled in the same way as Generating Units). Start-Up component contains:
Start-Up Time – The Start-Up Time is a staircase curve with up to three segments reflecting the conditions for Start-Up (Warm, Intermediate and Cold). The Start-Up Time (expressed in minutes) is expressed as a function of Cooling Time (expressed in minutes) and can range from zero to infinity. *(CAISO inserts registered Master File Data).*

Start-Up Cost – The Start-Up Cost is a staircase curve with up to three segments reflecting the conditions for Start-Up (Warm, Intermediate and Cold). Start-Up Cost is expressed in $, as a function of Cooling Time (in minutes) and can range from zero to infinity. The value used for Start-Up Cost is determined as follows:

If the SC has elected the Registered Cost option for Start-Up Cost and the SC submits registered value, CAISO overwrites any submitted Bid component with the Start-Up Cost data from the Master File. Under this option, the registered value can be changed every 30 days through the Master File change process.

If the SC has elected the Proxy Cost option for the Start-Up Cost, the CAISO calculates this value daily using the daily Gas Price Index and the Relative Proxy Start-up Cost Ceiling. In addition, SCs may include Start-Up Cost Bids into their DAM Bid submissions as long as the Start-Up Cost value is not negative and is less than or equal to the Start-Up Cost value calculated using the daily Gas Price Index. If the SC does not submit a Start-Up Cost Bid or when the submitted Start-Up Cost Bid is greater than the calculated Start-Up Cost, the CAISO uses the Start-Up Cost calculated using the daily Gas Price Index. The process used by CAISO to calculate the daily Gas Price Index is described in Attachment C.

Example of Start-Up Bid Component

<table>
<thead>
<tr>
<th></th>
<th>Cooling Time (Minutes)</th>
<th>Start-Up Time (Minutes)</th>
<th>Start-Up Cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Warm</td>
<td>0</td>
<td>600</td>
<td>6,500</td>
</tr>
<tr>
<td>Intermediate</td>
<td>240</td>
<td>1390</td>
<td>9,800</td>
</tr>
<tr>
<td>Cold</td>
<td>480</td>
<td>1400</td>
<td>12,000</td>
</tr>
</tbody>
</table>

If a value is submitted in the Bid for the Start-Up Cost it will be overwritten by the Master File value. If no value for Start-Up Cost is submitted in the Bid, CAISO will insert the Master File value for the Start-Up Cost into the bid.
The Start-Up Cost component is a daily Bid component and can be bid into both the DAM and the RTM. RTM submissions will not be used if the resources was committed in the DAM, the DAM Daily Components will be copied to the RTM bid.

If the SC has selected Registered Cost option for the Start-Up Cost, this value can be changed every 30 days through the Master File change process. The process used by CAISO to calculate the daily Gas Price Index is described in Attachment C. Whenever the Start-Up Cost submitted by the SC is overwritten, the CAISO notifies the SC that the daily Bid Start-Up Cost has been overwritten by the default values when the Bid confirmation is provided to the SC.

### A5.1.1.1.2 Minimum Load Cost Component

This Bid cost component applies to Generating Units and Proxy Demand Resources. The Minimum Load Cost component contains:

- The hourly cost of operating the Generating Unit at Minimum Load, expressed in $/hr.\textsuperscript{41}

The Minimum Load Cost can be bid into both the DAM and the RTM. RTM submissions will not be used if the resources was committed in the DAM, the DAM Daily Components will be copied to the RTM bid.

If the SC has elected the Registered Cost option for Minimum Load Cost, and the SC submits data for this component, CAISO overwrites the Bid component with the data from the Master File. If the SC selected Registered Cost Minimum Load Cost, this value can be changed every 30 days through the Master File.

If the SC has elected the Proxy Cost option for Minimum Load Cost, CAISO calculates this value daily based on the daily Gas Price Index. In addition, SCs may include Minimum Load Cost Bids into their DAM Bid as long as the value is not negative and is less than or equal to the Minimum Load Cost value calculated using the daily Gas Price Index and the Relative Proxy Minimum Load Cost Ceiling. If the SC does not submit a Minimum Load Cost Bid or when the submitted Minimum Load Cost Bid is greater than the calculated Minimum Load Cost, the CAISO uses the Minimum Load Cost calculated using the daily Gas Price Index. The process used by CAISO to calculate the daily Gas Price Index is described in Attachment C.

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\textsuperscript{41} If a value is submitted in the Bid for the Minimum Load Cost it will be overwritten by the Master File value. If no value for Minimum Load Cost is submitted in the Bid, CAISO will insert the Master File value for the Minimum Load Cost into the bid.
The CAISO notifies the SC that the Minimum Load Cost component has been overwritten by the default values when the Bid confirmation is provided to the SC.

A8.2.1.3 SIBR Generated Bid (Physical Bids only)

In the event that SIBR must generate a Bid or Bid component to comply with Tariff requirements SIBR will generate a Bid or Bid component for the resource. There is a series of processing rules that are executed to establish the Start-Up and Minimum Load Cost in SIBR to generate the Bid with the proper Start-Up and Minimum Load costs based on the resource’s election of either the Proxy Cost Option or the Registered Cost Option, and if it is a Natural Gas resource or Non-Natural Gas resource. Registered Cost resources use the values provided for the resource that are in the Master File.

Resources that are subject to CAISO Tariff Appendix II must select the Proxy Cost Option for Start-Up and Minimum Load costs. The SIBR Rules (Appendix A) sections 411xx (Generating Resource Start-Up Bid Component Processing and Generating Resource Minimum Load Cost Bid Component Processing detail the generation of these costs.

Start-Up Bid Component

If the Registered Cost Option is selected, a Registered Start-Up Cost will be generated. See Attachment G for details.

If the Proxy Cost Option is selected, the following two curves will be generated for a Start-Up Bid component if the Scheduling Coordinator has not submitted a Start-Up Bid component, or if the submitted Start-Up Bid component is higher than the proxy cost:

3. The Start-Up Time Bid Curve - this is the registered value retrieved from Master File for the resource and most current Trading Day.

4. The Start-Up Cost Curve - this is calculated using the following information:


   c. Greenhouse Gas Start-Up Cost Allowance Curve (if applicable – see Attachment K for details).

   d. Major Maintenance Start-Up Cost Adder (if applicable – see Attachment L for details).
e. Grid Management Charge (GMC) Start-Up Cost Adder (Minimum Load * GMC Adder * (shortest Start-Up Time/60) * .5). The GMC Adder is made up of the Market Services Charge and System Operations Charge components.

f. Relative Proxy Start-Up Cost Ceiling (125%) – for validation of submitted Start-Up Bid Component.


For examples of a Start-Up Bid component calculation, see Attachment G.

**Minimum Load Cost Component**

If the Registered Cost Option is selected, a Registered Minimum Load Cost will be generated. See Attachment G for details.

If the Proxy Cost Option is selected, the Minimum Load Cost is generated using the following information if the Scheduling Coordinator has not submitted a Minimum Load Cost bid, or if the submitted Minimum Load Cost bid is higher than the proxy cost:

6. Minimum Load Fuel Cost – the product of the Minimum Load Heat Rate, the Minimum Load, and the daily Gas Price Index.

7. Operation and Maintenance Minimum Load Cost - the product of the registered Operation and Maintenance Cost and the registered Minimum Load. Alternatively, a custom O&M adder may be negotiated with the CAISO or the Independent Entity.


9. Major Maintenance Minimum Load Cost Adder (if applicable – see Attachment L for details).

10. Grid Management Charge (GMC) Minimum Load Cost Adder - product of the GMC Minimum Load Cost Adder and the registered Minimum Load. The GMC Minimum Load Cost Adder is made up of the Market Services Charge and System Operations Charge components and a third value representing the Bid Segment Fee component divided by the resource Pmin.


For examples of a Minimum Load Cost Component calculation, see Attachment G.

**Energy Bid Component**

An Energy Bid will be generated as provided in accordance with the CAISO’s SIBR rules using the following information if the Scheduling Coordinator has not submitted an Energy Bid:

4. Energy cost curve – product of the incremental heat rate curve multiplied by the Gas Price Index.

5. Operation and Maintenance (O&M) cost - specified in Exhibit 4-2. Alternatively, a custom O&M adder may be negotiate with the CAISO or the Independent Entity.

6. 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 component divided by the bid segment MW size.

Energy Bid curve = energy cost curve + O&M cost + GMC adder.

Below is an example of how the Bid is generated for Generating Units and Resource Specific System Resources. Additional examples are contained in Attachment F. For non-Resource Specific System Resources, please see Appendix Attachment I.

**Bid Curve Generation Example**

The Generating Unit in the following example is registered as a natural gas resource. The following registered Master File data is used in the example. These values are for illustrative purposes only:

<table>
<thead>
<tr>
<th>Operating Levels</th>
<th>Average Heat Rate</th>
<th>Gas price index</th>
<th>Operation &amp; Maintenance Cost</th>
<th>Grid Management Charge adder</th>
</tr>
</thead>
<tbody>
<tr>
<td>70</td>
<td>14440</td>
<td>$5.5</td>
<td>$2.80</td>
<td>$0.50</td>
</tr>
<tr>
<td>150</td>
<td>11960</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>300</td>
<td>10909</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>485.17</td>
<td>10366</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
1) Generated Energy Curve Calculation

The generated Energy Curve is calculated as the sum of the Incremental Fuel Cost curve (calculated in section 3 and 4 below), the registered Operation and Maintenance Cost ($/MWh), and the GMC adder.

\[
\text{Segment 1} - (53.85 + 2.80 + 0.50) = \$57.15 \\
\text{Segment 2} - (54.22 + 2.80 + 0.50) = \$57.52 \\
\text{Segment 3} - (52.17 + 2.80 + 0.50) = \$55.47 \\
\]

The resulting Energy Curve is:

- 70MW – 150MW @ $57.15
- 150MW – 300MW @ $57.52
- 300MW – 485.17MW @ $55.47

The Generated Energy curve must be adjusted to be monotonically increasing. If a Generated Energy Bid Curve is not monotonically increasing, CAISO adjusts the Energy Bid price of each Energy Bid segment after the first one, to the previous Energy Bid segment, if higher, and the two Energy Bid segments are merged in the Energy Bid Curve.

2) Final Generated Energy Curve

70MW - 150MW @ 57.15

150MW – 485.17 MW @ 57.52

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

3) Incremental Fuel Cost Curve Calculation

The Incremental Fuel Cost Curve used to derive the Energy Bid Curve must be calculated as the product of the Incremental Heat Rate Curve and the registered Gas Price Index ($/MMBtu) for that Trading Hour and the Generating Resource specified in that Bid, if that Generating Resource is registered as a Natural Gas Resource for that Trading Hour.

Segment 1 - 9790/1000 * 5.5 = 53.85
Segment 2 – 9858/1000 * 5.5 = 54.22
Segment 3 – 9486/1000 * 5.5 = 52.17

4) Incremental Heat Rate Calculation

The Incremental Heat Rate of the Incremental Heat Rate Curve segment between two Operating Levels is calculated as the ratio of the difference between the product of the registered Average Heat Rate at the higher Operating Level times that Operating Level, minus the product of the registered Average Heat Rate at the lower Operating Level times that Operating Level, over the difference between the higher Operating Level and the lower Operating Level.

Segment 1 – ((11960 * 150) – (14440 * 70))/(150 – 70) = 9790
Segment 2 – ((10909*300) – (11960 * 150))/(300-150) = 9858
Segment 3 – ((10366*485.17) –(10909 * 300))/(485.17 – 300) = 9486

5) Minimum Load Cost Calculation


6) Transition Cost Calculation - See Attachment H of this BPM for details.

Generator Resource – May request data change

This table contains operational data for the Generator resources where changes to the data can be initiated by the Market Participants via the RDT update process. The field names are listed in the order they appear in the GRDT.
<table>
<thead>
<tr>
<th>Master File Field Name (RDT Column Name)</th>
<th>Definition</th>
<th>Parameter and/or Enumerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>MAX_GEN (Maximum Generation Capacity)</td>
<td>The Net Dependable Capacity (NDC or PMAX) a Generator Resource can produce on a sustained basis as measured at or compensated to the Generating Unit’s defined point of delivery.</td>
<td>Cannot be null</td>
</tr>
</tbody>
</table>
| MIN_GEN (Minimum Generation Capacity)   | The minimum output level at which a Generator Unit can operate.  
Note: Depending on schedules and bids submitted in the market, the CAISO may dispatch units in the real-time market between the values of min gen and max gen. Therefore, the CAISO strongly recommends that the min gen level be set at the Minimum Output Level (PMIN) at which a Generator Unit can operate on a sustained basis. | Cannot be null |
<p>| MIN_DISP_LEVEL (Minimum Dispatchable Level) | The Minimum operating level at which a Generating Unit is able to readily respond to a dispatch instruction. | |
| MIN_ON (Minimum On Time)               | The minimum amount of time that a Generating Unit must stay on-line after starting up and reaching PMin, prior to being shut down, due to physical operating constraints. In case of a Pump Storage resource, this field represents the minimum time that the resource must stay on-line in the generating mode prior to being shut down. | Cannot be null if Fuel Type is equal to GAS |
| MAX_ON (Maximum On Time)               | The maximum amount of time that a Generating Unit can stay on-line per day, due to environmental or physical operating constraints. | If no constraint, then leave this field blank |
| MIN_OFF (Minimum Off Time)             | The minimum amount of time that a Generating Unit must stay off-line after being shut down, due to physical operating constraints. In case of a Pump Storage resource, this field represents the minimum time that the resource must stay off-line after being shutdown from the generating mode prior to being started again in the generating mode. | |
| MAX_STRRT (Maximum Startups Per Day)   | The maximum number of times a Generating Unit can be started up within one day, due to environmental or physical operating constraints. | Cannot be null |</p>
<table>
<thead>
<tr>
<th>Master File Field Name (RDT Column Name)</th>
<th>Definition</th>
<th>Parameter and/or Enumerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>MIN_LOAD_COST (Minimum Load Cost)</td>
<td>The costs a Generating Unit or a Participating Load incurs operating at minimum load.</td>
<td>The value is needed for a resource with the Cost Basis of Registered Cost (fixed value) only.</td>
</tr>
</tbody>
</table>
| ML_COST_BASIS_TYPE (Minimum Load Cost Basis Type) | 30 days Election of the type of Operational Cost used for maintaining operation at Minimum Load:  
- If Proxy Cost: The Operating Cost of a generating resource is calculated using the Heat Rate data in the Master File and daily gas price. (PRXC). The SC is also allowed to submit a daily component in either DAM or RTM bid for Minimum Load Cost as long as the bid is not negative and less than or equal to the calculated Minimum Load Cost based on the Heat Rate, Daily Gas Price Index and the Operations and Maintenance (O&M) adder.  
- If Registered Cost: Please refer to Attachment G. | If RES_TY_PE = GEN or TG then ML_COST_BASIS_TYPE can be null, must be filled with one of the following: PRXC - Proxy Cost REGC - Registered Cost |
| SU_COST_BASIS_TYPE (Start-Up Cost Basis Type) | 30 days Election of the type of Operational Cost used for Start-Up:  
- If Proxy Cost: The Start-Up Cost of a generating resource is calculated using the Start-Up data in the Master File and daily gas price. (PRXC). The SC is also allowed to submit a daily component in either DAM or RTM bid for Start-Up Cost as long as the bid is not negative and is less than or equal to the calculated Start-Up Cost based on the Start-Up data and daily gas price.  
- If Registered Cost: Please refer to Attachment G. | If RES_TY_PE = GEN or TG then SU_COST_BASIS_TYPE can be null, must be filled with one of the following: PRXC - Proxy Cost REGC - Registered Cost |
<p>| MAX_PUMP (Maximum Pump Capacity)       | The Maximum Operating Level of a Pump or a Pumped-Storage-Hydro Unit operating as a hydro pump | Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP |
| MIN_PUMP_CST (Pumping Minimum Cost)    | The minimum cost to start the pump up. | MIN_PUMP_CST cannot be null if GEN_TECH_TYPE = PTUR or PUMP |
| PUMPING_FACTOR (Pumping Factor)        | The efficiency or recovering energy potential in pumping water from the lower to the upper reservoir. | Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP |
| PUMP_MAX_STRT (Pump Maximum Daily Startups) | The maximum number of times a Pumped Storage Hydro Resource can switch into pumping mode during a Trading Day. | Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP |</p>
<table>
<thead>
<tr>
<th>Master File Field Name (RDT Column Name)</th>
<th>Definition</th>
<th>Parameter and/or Enumerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>PUMP_MIN_UP_TM (Pump Minimum Up Time)</td>
<td>The minimum time that a Pumped Storage Hydro Resource must stay in pumping mode after switching to that mode.</td>
<td>Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP</td>
</tr>
<tr>
<td>PUMP_MIN_DWN_TM (Pump Minimum Down Time)</td>
<td>The minimum time that a Pumped Storage Hydro Resource must stay out of pumping mode after switching out of that mode.</td>
<td></td>
</tr>
<tr>
<td>MIN_DWN_TM_GP</td>
<td>The Gen-to-Pump minimum down time applies to Pump Storage Resources and reflects the minimum time (in minutes) that the resource must be offline (or self-scheduled) after being de-committed from generation mode and before being dispatched in pumping mode.</td>
<td></td>
</tr>
<tr>
<td>MIN_DWN_TM_PG</td>
<td>The Pump-to-Gen minimum down time applies to Pump Storage Resources and reflects the Minimum time (in minutes) that the resource must be offline (or self-scheduled) after being de-committed from pumping mode and before being dispatched in generation mode.</td>
<td></td>
</tr>
<tr>
<td>MAX_PUMP_SD_CST (Pump Maximum Shutdown Cost)</td>
<td>The maximum cost it would take to shutdown the pump.</td>
<td>MAX_PUMP_SD_CST cannot be null if GEN_TECH_TYPE = PTUR or PUMP</td>
</tr>
<tr>
<td>PUMP_SHTDWN_TM (Pump Shutdown Time)</td>
<td>The pump shutdown time.</td>
<td></td>
</tr>
<tr>
<td>COST_RANK_LMPM (Variable Cost Option)</td>
<td>A method of calculating Default energy Bids based on fuel costs and variable operations and maintenance costs.</td>
<td>Rank 1, 2, or 3</td>
</tr>
<tr>
<td>NEGO_RANK_LMPM (Negotiated Rate Option)</td>
<td>A method of calculating Default energy Bids based on a negotiation with the CAISO or the Independent Entity.</td>
<td>Rank 1, 2, or 3</td>
</tr>
<tr>
<td>PRC_RANK_LMPM (LMP Option)</td>
<td>A method of calculating Default energy Bids based Locational Marginal Prices.</td>
<td>Rank 1, 2, or 3</td>
</tr>
<tr>
<td>RSRV_CAP_SPIN (Reserve Capacity: Spin)</td>
<td>The portion of unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and that is capable of running for at least 30 minutes.</td>
<td></td>
</tr>
<tr>
<td>RSRV_CAP_NSPIN (Reserve Capacity: Non-Spin)</td>
<td>The portion of off-line generating capacity that is capable of being synchronized and Ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least 30 minutes.</td>
<td></td>
</tr>
<tr>
<td>Master File Field Name (RDT Column Name)</td>
<td>Definition</td>
<td>Parameter and/or Enumerations</td>
</tr>
<tr>
<td>----------------------------------------</td>
<td>------------</td>
<td>------------------------------</td>
</tr>
<tr>
<td>CERT_REG (Certified for AS: Regulation - CERT_REG)</td>
<td>An identifier of a resource that is certified to provide Regulation Reserve.</td>
<td></td>
</tr>
<tr>
<td>CERT_SPIN (Certified for AS: Spin - CERT_SPIN)</td>
<td>An identifier of a resource that is certified to provide Spinning Reserve.</td>
<td></td>
</tr>
<tr>
<td>CERT_NSPIN_DAM (Certified for AS DAM: Non-Spin - CERT_DAM_NON_SPI N)</td>
<td>An identifier of a resource that is certified to provide Non-Spinning Reserve in the DAM.</td>
<td></td>
</tr>
<tr>
<td>CERT_NSPIN_RTM (Certified for AS RTM: Non-Spin - CERT_RTM_NON_SPI N)</td>
<td>An identifier of a resource that is certified to provide Non-Spinning Reserve in the RTM. To be procured in the RTM, a unit must also have a Startup Code Type of FAST.</td>
<td></td>
</tr>
<tr>
<td>REM (Regulation Energy Management)</td>
<td>Indicator of a non-generator resource that can only provide regulation energy</td>
<td></td>
</tr>
<tr>
<td>MIN_CONT_ENERGY_LIMIT (Minimum Continuous Energy Limit)</td>
<td>Minimum stored energy for an NGR. If no real physical energy limit, leave blank.</td>
<td></td>
</tr>
<tr>
<td>MAX_CONT_ENERGY_LIMIT (Maximum Continuous Energy Limit)</td>
<td>Maximum stored energy for an NGR. If no real physical energy limit, leave blank.</td>
<td></td>
</tr>
<tr>
<td>CURT_ENERGY_LIMIT (Curtailment Energy Limit)</td>
<td>The energy limit for curtailing the consumption of energy for NGR. If no limit, leave blank. This is a placeholder for future functionality.</td>
<td></td>
</tr>
<tr>
<td>ENERGY_EFFIC (Energy Efficiency)</td>
<td>The percentage of charging energy that the device can store and later discharge; 0&lt;= n &lt;=1</td>
<td></td>
</tr>
<tr>
<td>RMT_MAX_ON_PEAK</td>
<td>For CHP resources, the portion of capacity that is eligible for Reliability Must-Take scheduling priority during on-peak hours. Must be reestablished annually. If there is no off-peak value established, this value will be used in all hours.</td>
<td></td>
</tr>
<tr>
<td>RMT_MAX_ON_PEAK_EXP_DT</td>
<td>Expiration date of the stated RMTG-eligible capacity</td>
<td></td>
</tr>
<tr>
<td>Master File Field Name (RDT Column Name)</td>
<td>Definition</td>
<td>Parameter and/or Enumerations</td>
</tr>
<tr>
<td>------------------------------------------</td>
<td>------------</td>
<td>-----------------------------</td>
</tr>
<tr>
<td>RMT_MAX_OFF_PEAK</td>
<td>For CHP resources, the portion of capacity that is eligible for Reliability Must-Take scheduling priority during off-peak hours. This value is optional. Must be reestablished annually.</td>
<td></td>
</tr>
<tr>
<td>RMT_MAX_OFF_PEAK_EXP_DT</td>
<td>Expiration date of the stated RMTG-eligible capacity</td>
<td></td>
</tr>
<tr>
<td>EMISSION_RATE</td>
<td>For gas-fired resources, the emission rate (mtCO2/mmBTU) used to determine a resource's greenhouse gas compliance obligation</td>
<td></td>
</tr>
<tr>
<td>GHG_COMPLIANCE_OBLIG</td>
<td>Indicator of a resource that has a greenhouse gas compliance obligation and is, therefore, eligible to recover greenhouse gas allowance costs</td>
<td></td>
</tr>
<tr>
<td>FORECAST_OWNER</td>
<td>Indicator for whether a resource will provide its own forecast or will utilize the ISO's forecast</td>
<td></td>
</tr>
</tbody>
</table>

### G.2.1.1 Maximum Proxy Cost Start-up Costs

For purposes of determining maximum Start-up costs\(^{42}\) that may be approved for gas-fired units under the Proxy Cost Option, the calculated Start-up costs will be calculated by combining the unit’s Startup fuel and electrical energy consumption curves in the Master File, the daily Gas Price Index calculated as described in Attachment C and the electricity price index as described in attachment M, plus a Grid Management Charge (GMC) adder representing the Market Services Charge and System Operations Charge components. 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), the CAISO will add to the calculated Start-up costs the greenhouse gas allowance start-up cost. The cost will be calculated per Attachment K, using the Greenhouse Gas Allowance Price described in Attachment K. In addition, if the resource has major maintenance expenses approved by the CAISO, the CAISO will add a major maintenance cost adder (MMA). See Attachment L for details.

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\(^{42}\) Multi-stage generating resources have both start-up and indicative start-up costs, as described in greater detail in Attachment H. This section refers to both generically as start-up costs.
For purposes of this calculation, the cost of any auxiliary power needed for start-up (as indicated in the STARTUP_ENERGY field in the Master File) will be calculated multiplying the MWh energy input with the Electricity Price Index. See Attachment M for details.

A Scheduling Coordinator may bid Start-up Costs daily in either DAM or RTM, RTM submissions will not be used if the resources was committed in the DAM, the DAM Daily Components will be copied to the RTM bid. The Start-up Cost bid for a unit cannot exceed the applicable limit of 125 percent of the unit's calculated Proxy Cost for Start-up Costs. For multi-stage generating resources, a Scheduling Coordinator may bid Transition Costs daily. The Transition Cost bid for a unit cannot exceed the applicable limit of 125 percent of the unit's calculated Proxy Cost for Transition Costs. If the Scheduling Coordinator does not bid, the CAISO will generate daily bids based on the calculated Proxy Costs.

**Example: Proxy Start-up Cost Calculation and Bid Cap for Gas-Fired Resource**

An example of this calculation based on a natural gas price index of $8.50/MMBtu is provided in the following table.

For purposes of the GMC adder, assume a PMin of 20 MW, a Start-Up Time Period of 600 minutes, and a GMC adder of $0.50/MWh (made up of a $0.15/MWh Market Services Charge and a $0.35/MWh System Operations Charge). Note that the fastest Start-Up Time Period registered in the Master File is used in this calculation, regardless of segment. In other words, even for warm starts or cold starts, the fastest start-up time will be used. For MSG resources this applies to each configuration. That is, the fastest time period registered for the segment, not the entire resource, will be used.

\[
\text{Start-Up Cost} = (\text{Start-Up Fuel} \times \text{Gas Price}) + (\text{Start-Up Energy} \times \text{Electricity Price Index}) + (\text{PMin} \times \text{Start-Up Time Period in min} / 60 \text{ min/hour} \times \text{GMC adder} / 2)
\]

\[
\text{Gas price index} = 8.50/\text{MMBtu}
\]

**Example of start-up cost calculation (first Start-Up segment):**

\[
\text{Start-Up Cost} = (1,083 \text{ MMBtu} \times \$8.50/\text{MMBtu}) + (20\text{MWh} \times \$80/\text{MWh}) + (20 \text{ MW} \times (600 \text{ minutes}/(60 \text{ minutes/hour})) \times \$0.50/\text{MWh} / 2)
\]

\[
= (9,205.5) + (1,600) + (50)
\]

\[
= 10,855.50
\]

\[
= 10,856 \text{ (rounded)}
\]

43 See Attachment H for transition cost calculations.
Start-Up Costs including a GHG Compliance Obligation:

Start-Up Cost = (Start-Up Fuel x Gas Price) + (Start-Up Energy x Electricity Price Index) + (PMin x Start-Up Time Period in min / 60 min/hour x GMC adder / 2) + (Start-Up Fuel x GHG Emission Rate x GHG Allowance Price)

GHG Allowance Price = $15.34/mtCO\textsubscript{2e}
GHG Emission Rate = 0.053165 mtCO\textsubscript{2e}/MMBtu

Example of start-up:
Start-Up Cost = (1,083 MMBtu x $8.50/MMBtu) + (20MWh x $80/MWh) + (20 MW x (600 minutes / (60minutes/hour)) x $0.50/MWh / 2) + (1083 MMBtu x 0.053165 mtCO\textsubscript{2e} /MMBtu x $15.34)

= (9,205.5) + (1,600) + (50) + (883.24)
= 11,738.74
= 11,739 (rounded)

Start-Up Costs including a major maintenance cost adder:

The major maintenance cost adder is a single line item that is added to the Start-Up Cost. Continuing the example above:

Assume major maintenance cost adder approved by the CAISO is $800.98 (same value applied to all segments).
Start-Up Cost = $11,738.74 + major maintenance cost adder
= $11,738.74 + 800.98
= $12,539.72
= $12,540 (rounded)

Table G3. Example of Calculated Start-up Cost and Maximum Proxy Cost Bid Calculation (Gas Price = $8.50/MMBtu, EPI = $80/MWh)

<table>
<thead>
<tr>
<th></th>
<th>Cooling Time</th>
<th>Start-Up Time</th>
<th>Start-Up Fuel</th>
<th>Start-Up Energy</th>
<th>Start-Up Cost w/o GHG/MMA ($)</th>
<th>Start-Up Cost w/ GHG &amp; MMA ($)</th>
<th>Max Start-Up Bid w/o GHG/MMA ($)</th>
<th>Max Start-Up Bid w/ GHG &amp; MMA ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hot</td>
<td>0</td>
<td>600</td>
<td>1,083</td>
<td>20</td>
<td>$10,856</td>
<td>$12,540</td>
<td>$13,569</td>
<td>$15,675</td>
</tr>
<tr>
<td>Warm</td>
<td>240</td>
<td>1390</td>
<td>1,633</td>
<td>40</td>
<td>$17,196</td>
<td>$19,329</td>
<td>$21,495</td>
<td>$24,161</td>
</tr>
</tbody>
</table>
G.2.1.2 Maximum Proxy Cost Minimum Load Costs

For purposes of determining maximum Minimum Load Cost that may be calculated for gas-fired units under the Proxy Cost Option, the calculated Minimum Load Cost will be calculated using the unit’s Minimum Load Heat Rate and the daily Gas Price Index calculated as described in Attachment C, plus a GMC adder made up of the Market Services Charge and System Operations Charge components and a third value representing the Bid Segment Fee component divided by the resource Pmin. 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), the CAISO will add to the calculated Minimum Load Cost the Greenhouse gas allowance minimum load cost. The cost will be calculated using the Greenhouse Gas Allowance Price described in Attachment K. In addition, if the resource has minimum load major maintenance adder approved by the CAISO, the CAISO will add a major maintenance cost adder (MMA). See Attachment L for details.

A Scheduling Coordinator may daily bids for Minimum Load Costs daily in either DAM or RTM, RTM submissions will not be used if the resources was committed in the DAM, the DAM Daily Components will be copied to the RTM bid. The Minimum Load Cost bid for the unit cannot exceed the cap of 125 percent of the unit’s calculated Proxy Cost for Minimum Load Costs. If the Scheduling Coordinator does not bid, the CAISO will generate daily bids based on the calculated Proxy Costs. The calculation and an example are provided below.

Example: Proxy Minimum Load Cost Calculation and Bid Cap for Gas-Fired Resource

Minimum Load Cost Cap = (Unit Conversion Factor x Minimum Load Heat Rate x Minimum Operating Level x Gas Price) + (O&M x Minimum Operating Level) + (GMC adder x Minimum Operating Level)

Example:
Gas price index = 8.50/MMBtu
O&M adder = $4/MWh
GMC adder = $0.50/MWh
Minimum Load Cost = (0.001 x 14,000Btu/kWh x 20MW x $8.50/MMBtu) + ($4/MWh$^{44} \times 20\text{MW}) + ($0.50/MWh \times 20\text{MW})
= ($2,380) + ($80) + ($10)
= $2,470

Minimum Load Cost with a GHG component = (Unit Conversion Factor \times Minimum Load Heat Rate \times Minimum Operating Level \times Gas Price) + (O&M \times Minimum Operating Level) + (GMC adder \times Minimum Operating Level) + (Minimum Operating Level \times Unit Conversion Factor \times Minimum Load Heat Rate \times Emission Rate \times GHG Allowance Price)

Example:
Emission Rate = 0.053165 \, \text{mtCO}_2e/\text{MMBtu}
GHG Allowance Price = $15.34/\text{mtCO}_2e

= (0.001 \times 14,000\text{Btu/kWh} \times 20\text{MW} \times $8.50/\text{MMBtu}) + ($4/MWh \times 20\text{MW}) + ($0.50/MWh \times 20\text{MW}) + (20\text{MW} \times 0.001 \times 14,000\text{Btu/kWh} \times 0.053165 \, \text{mtCO}_2/\text{MMBtu} \times 15.34)
= ($2,380) + ($80) + ($10) + ($228)
= $2,698

Minimum Load Costs including a major maintenance cost adder:

The major maintenance cost adder is a single line item that is added to the Minimum Load cost. Continuing the example above:

Assume major maintenance cost adder approved by the CAISO is $105.19.
Minimum Load Cost = $2,695 + major maintenance cost adder
= $2,695 + 105
= $2,803

Table G4. Example of Calculated Minimum Load Cost and Maximum Bid Calculation

<table>
<thead>
<tr>
<th>Minimum Operating Level (MW)</th>
<th>Heat Rate (MBtu/MWh)</th>
<th>O&amp;M Cost ($/MWh)</th>
<th>Minimum Load Cost ($)</th>
<th>GHG Allowance Cost &amp; MMA ($/MWh)</th>
<th>Minimum Load Cost with GHG &amp; MMA ($)</th>
<th>Max MLC Bid w/o GHG/MM A ($)</th>
<th>Max MLC Bid with GHG &amp; MMA ($)</th>
</tr>
</thead>
</table>

$^{44}$ This example assumes a $4/MWh O&M adder.
Number 6

Attachment N
Gas Constraint using generation nomograms

AN Gas Constraint using generation nomograms

- Please refer to Managing Full Network BPM
  https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Managing Full Network Model Section 4.2.7.1.2 for Gas Constraint using Generation Nomograms.