Business Practice Manual for Market Instruments

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Approval History

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BPM Owner's Title: Director of Operational Readiness

Revision History

Version	Date	Description
53	05/02/2019	PRR1141 This is related to the stakeholder feedback for improvements for business needs related to the EIM resource sufficiency evaluation. Effective date is 4/16/19 PRR1143 Updating the content of attachment J by simply referencing the Reliability Requirements BPM for the market rules content.
52	04/02/2019	PRR1129 Added comment in sec B.2.2 table to clarify the Participating Generator Agreement Flag for the Generator Resource Data Template. PRR1135 The Commitment Cost Enhancements Phase 3 initiative changes the definition of Use-Limited Resources and allows Use-Limited Resources to include opportunity costs in their commitment costs or default energy bids, where applicable. Effective date: April 1, 2019 This will impact the following attachments: Attachment D Attachment G Attachment H New Attachment N Section 8.2.1.3 PRR1149 Attachment B updates due to Commitment Cost Enhancement Phase 3 project. Effective Date: April 1, 2019
51	02/27/2019	PRR1115 Updating Greenhouse Gas allowance price inputs and fallback logic. Attachments C & K. PRR1118 new report definition in section 12.4 due to FERC 844 PRR1145 Addition of a new CRR Revenue Adjustments Detail

Version	Date	Description
		report definition due to CRR 1B enhancement project.
50	11/05/2018	PRR1110 Due to the extension of Aliso Canyon Tariff provisions. CAISO will extend the temporary measures beyond December 16th. New repot definition due to CRR 1B project.
48	08/08/2018	PRR1065 - Section G.1 update is to improve the efficiency of the monthly validation of registered costs process. Other miscellaneous updates to sections 10 and 12 for report definitions.
47	02-13-2018	PRRs 1034 & 1037 • Due to the extension of Aliso Canyon Tariff provisions. CAISO will extend the temporary measures beyond November 30, 2017. Miscellaneous updates to paragraph 10.1
46	10-30-2017	PRR 1013 New fuel regions and electric regions for use in commitment costs. This is due to Bidding Rules Enhancement part B project.
45	10-06-2017	PRR 1003 includes two changes; (1) Changing the scaling factors to the gas price index due to Aliso Canyon. Effective August 1st, 2017. • (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 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

Version	Date	Description
		Attachments C & M
38	10-01-2015	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
37	05-4/2015	PRR829 added a new section M to describe the Electricity Price Index calculation
36	03-05-2015	PRR 824 added a new language due to price spike process pursuant to Tariff section 39.7.1.1.1.3(b)
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.
28	06-04-2013	PRR 661 for demand response net benefits test. Changes made to Appendix Attachment C sections C.1 and C.3. New section C.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.

Version	Date	Description
27	05-12-2013	PRR 654 for Treatment of Market Participants with Suspended Market-Based Rate Authority. Changes made to sections 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.
26	03-12-2013	PRR 638 for Circular Scheduling. New section 3.4.3 added.
25	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.
23	11-12-2012	PRR 570 for Contingency dispatch enhancements part 1. Change made to section 11.1. 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.
21	05-07-2012	PRR 540 for Bidding enforcement rules for NRS-RA resources. New Appendix Attachment J added. 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

Version	Date	Description
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, 2.2.2, 5.1.3, 10.1, 12.1, and 12.4, Appendix Attachment D sections D.1, D.7, and Appendix Attachment E sections E.2, E.3, and E.4. PRR 536 for Changes to support Multi-stage generation enhancements functionality. Changes made to sections 5.1.1.3, 5.1.4.3, 5.1.5.1.5, and Appendix Attachment A. 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.
19	02-17-2012	PRR 520 to Clarify the CRN report definition. Change made to section 10.1
18	12-08-2011	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. PRR 494 for Changes in support of Flexible Ramping Constraint initiative. Changes made to sections 10.1 and 12.1.
17	10-28-2011	PRR 472 for New OASIS reports - contingency run. Changes made to sections 12.1 and 12.4. PRR 478 for changes to support the 72 hr RUC initiative. Changes made to sections 2.1.3 and 2.1.4. PRR 481 for changes to support the grouping constraints initiative. Change made to section B.2.1. Added new section B.3.
16	09-19-2011	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
15	06-13-2011	PRR 425 for changes to RUC Availability Bids for RA resources. Changes made to sections 3.3 and 7.1 PRR 427 for changes associated with the Ramping Flexibility Nomogram initiative. Change made to section 12.1.
14	05-18-2011	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. PRR 412 for changes to Bidding and Mitigation of Commitment

Version	Date	Description
		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 to the table described in attachment B section B.2.1.
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.
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

Version	Date	Description
		edits. (PRR 88)
2	08-11-2009	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)
1.0	03-27-2009	Initial Posting

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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.

Exhibit 1-1: CAISO BPMs

Title
BPM for Candidate CRR Holder Registration
BPM for Change Management
BPM for Compliance Monitoring
BPM for Congestion Revenue Rights
BPM for Credit Management
BPM for Definitions & Acronyms
BPM for Managing Full Network Model
BPM for Market Instruments
BPM for Market Operations
BPM for Metering
BPM for Outage Management
BPM for Reliability Requirements
BPM for Rules of Conduct
BPM for Scheduling Coordinator Certification and Termination
BPM for Settlements and Billing
BPM for Transmission Planning Process

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.

[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) only[3]. 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. 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

- Regulation Down
- Spinning Reserve

Non-Spinning Reserve

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[4]. 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[5] 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.

[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, 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 4-1: Daily & Hourly Bid Components

	Daily Components	Hourly Components	Submitted through SIBR	Comment
Start-Up	✓		**Yes, only if proxy cost option is**	If the resource has elected to use Registered Cost, the

	Daily Components	Hourly Components	Submitted through SIBR	Comment
			currently effective for Start-Up Cost in Master File.	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.
Minimum Load	✓		**Yes, only if Proxy Cost option is currently effective for Minimum Load Cost in Master File.**	If the resource has elected to use Registered Cost, the Minimum Load cost 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.
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.

	Daily Components	Hourly Components	Submitted through SIBR	Comment
Energy Bid Curve		✓	✓	
Self-Schedule		✓	✓	
Ancillary Services				Bid cannot contain more than certified quantities for each service.
Regulation Down		✓	✓	
Regulation Up		✓	✓	
Spinning Reserve		✓	✓	
Non-Spinning Reserve		✓	✓	
Ramp Rate	✓		✓	Bid by SC, within limits of the minimum and maximum Ramp Rates in the Master File.
Operational Ramp Rate	✓		✓	
Operating Reserve Ramp Rate	✓		✓	
Regulation Ramp Rate	✓		✓	
Contingency Dispatch Indicator	✓		✓	Must be selected if any AS is part of the Bid/Schedule.
Intertie Minimum Hourly Block (DA)		✓	✓	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.
Dispatch Option		✓	✓	A Bid option that determines the participation of an Intertie resource in the Real-Time Market:

	Daily Components	Hourly Components	Submitted through SIBR	Comment
				• 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 in each 5 minute Dispatch Interval of a Trading Hour.
Pump Shut-Down Cost		✓	✓	
Pumping Cost		✓	✓	
Energy Limit (Maximum and Minimum Daily)	✓		✓	
RUC		✓	✓	
Capacity Limit		✓	✓	(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

	Daily Components	Hourly Components	Submitted through SIBR	Comment
				award when bidding multiple services.
Distribution Factors		✓	✓	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.
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 4-2: Default O&M Cost Adders effective April 1, 2012 ($/MWh)

Generation Technology	Recommended VOM Cost Adder ($/MWh)
Solar	$0.00
Nuclear	$1.00
Coal	$2.00
Wind	$2.00
Hydro	$2.50
Combined Cycle and Steam	$2.80

Generation Technology	Recommended VOM Cost Adder ($/MWh)
Geothermal	$3.00
Landfill Gas	$4.00
Combustion Turbine & Reciprocating Engine	$4.80
Biomass	$5.00

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

Bid component	Allowed for non REM?	Allowed for REM?	Comment
Start-Up	No	No	By nature NGRs do not have startup costs.
Minimum Load	No	No	By nature NGRs do not have minimum load costs.
Transition Costs	No	No	By nature NGRs do not have transition costs.
Energy Bid Curve	Yes	No	NGRs selecting the REM option are not allowed to participate in the energy market.

Bid component	Allowed for non REM?	Allowed for REM?	Comment
Self-Schedule	Yes	No	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.
Ancillary Services			NGRs are not allowed to self-provide Ancillary Services
Regulation Down	Yes	Yes	
Regulation Up	Yes	Yes	
Spinning Reserve	Yes	No	NGRs selecting the REM option are only allowed to supply regulation.
Non-Spinning Reserve	Yes	No	NGRs selecting the REM option are only allowed to supply regulation.
Operational Ramp Rate	Yes	Yes	NGRs are limited to two segments. One ramp rate for charging and one ramp rate for discharging
Operating Reserve Ramp Rate	No	No	NGRs are not allowed to submit Operating Reserve Ramp Rates. Operational Ramp rate shall be used for procurement of AS.
Regulation Ramp Rate	No	No	NGRs are not allowed to submit Regulation Ramp Rates. Operational Ramp rate shall be used for procurement of AS.
Contingency Dispatch Indicator	Yes	N/A	Does not apply to REM resources because they cannot supply spinning or non-spinning reserve.
Intertie Minimum Hourly Block	N/A	N/A	Does not apply to NGRs because NGRs must be located within the CAISO balancing authority.
Dispatch Option	N/A	N/A	Does not apply to NGRs because NGRs must be located within the CAISO balancing authority.
Pump Shut-Down Cost	No	No	By nature NGRs do not have pump shut-down costs.
Pumping Cost	No	No	By nature NGRs do not have pumping costs.
Daily Energy Limit (Maximum and Minimum Daily)	No	No	However NGRs do bid an upper and lower charge limit, which is a similar concept.

Bid component	Allowed for non REM?	Allowed for REM?	Comment
RUC	No	No	NGR Resources do not participate in RUC
Capacity Limit	Yes	Yes	
Distribution Factors	Yes	Yes	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.
VER Forecast	N/A	N/A	Does not apply to NGRs because NGRs cannot be a VER.
The following bid components apply to NGRs only			
Lower Charge Limit	Yes	Yes	Lowest stored energy that should be maintained in the device. Cannot be lower than the minimum stored energy value registered in the Master File.
Upper Charge Limit	Yes	Yes	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.
Initial DA State of Charge (SOC)	Yes	No	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.

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

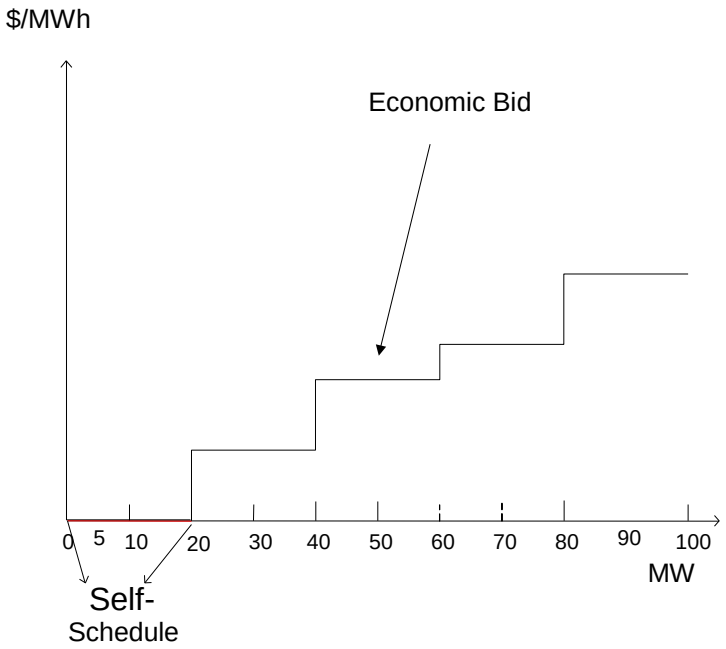
A description of the Bid requirements for Supply Bids

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.[6] 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

[6]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.

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

	Cooling Time (Minutes)	Start-Up Time (Minutes)	Start-Up Cost ($)
Warm	0	600	6,500
Intermediate	240	1390	9,800
Cold	480	1400	12,000

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.

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 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.

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.)**

[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.

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

5.1.1.1.4 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

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

Segment	Operating Level (MW)	Energy Price $/MWh
	500	75

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 File[8]) 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).

[8] Ramp Rates and Forbidden Regions are merged to create a single Clean Bid.

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.

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

MW	MW/Min
70	5
150	8
300	7
400	8
500	8

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:

MW	MW/Min
100	6
200	7
300	8
400	9
600	9

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

MW	MW/Min

MW	MW/Min
100	6
160	2
200	7
280	3
300	8
400	4
410	9
490	5
500	9
600	9

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)[9] 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.

[9] The Regulation Ramp Rate cannot be greater than any segment of the Operational Ramp Rate that is in the Bid.

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.

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[10]

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

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. [11]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

Pumped-Storage Hydro in Pump Mode Bid Components	*Compared to*	Pumped-Storage Hydro in Generator Mode Bid Components
Shut-Down Cost –		Generator's Start Up Cost
Pumping Level		MW Operating Point
Pumping Cost		Energy Bid component

[10] See Section 5.2.1.1 for a complete discussion of bidding rules, including for Energy Bids, for Aggregated Participating Load.

[11] While Participating Load is treated as negative generation in the IFM, SCs enter a positive value in the Bid.

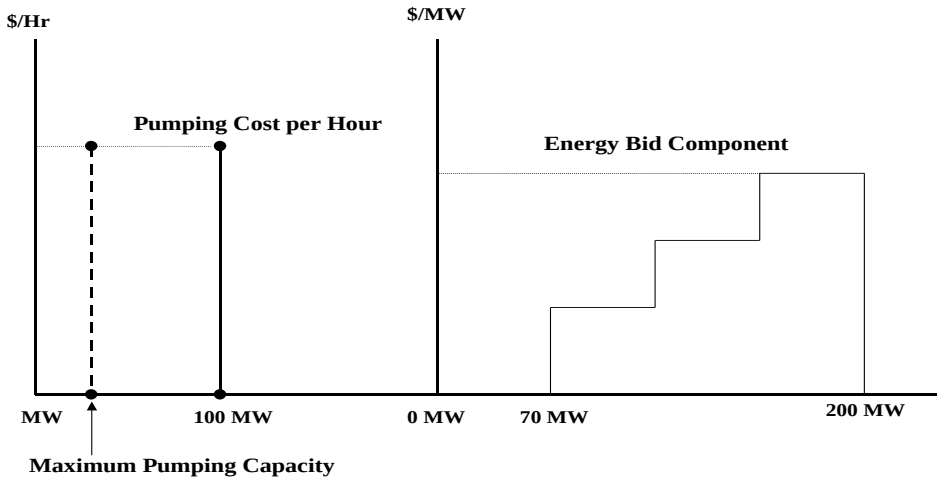


Exhibit 5-2 shows a Bid for a Pumped-Storage Hydro Unit that contains both Generation and Demand components for the same Trading Hour. In the above example, the Generation PMin is 70MW and the PMax is 200 MW. The unit submits a pumping bid of 100 MW.

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

Segment	Operating Level (MW)	Energy Price $/MWh
1	0	25
2	150	30
3	200	35
4	250	40
5	300	45
6	340	50
7	375	55
8	400	60
9	450	65

Segment	Operating Level (MW)	Energy Price $/MWh
10	475	75
	500	75

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

	Cooling Time (Minutes)	Start-Up Time (Minutes)	Start-Up Cost ($)
Warm	0	600	6,500
Intermediate	240	1390	9,800

[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.

Cold	480	1400	12,000

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[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.

[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

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

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.

MW	MW/Min
70	5
150	8
300	7
400	8
500	8

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.

5.2.1.1.1 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.

Generator Bid Components And Attributes	Corresponding Aggregated Participating Load Attributes
Start-Up Cost	Demand curtailment cost, *e.g.* Pump Shut Down Cost ($/curtailment event)
Start-Up Time	Demand curtailment time
Minimum Load	Must be **zero** to prevent unit commitment in the DAM
Minimum Load Cost	Set to **zero** since Minimum Load is set to zero
Maximum Capacity	Certified Non-Spinning Reserve capacity
Best/Worst Operating Reserve Ramp Rate	Certified Non-Spinning Reserve Ramp Rate
Best/Worst Operational Ramp Rate	Best/worst Demand curtailment rate (Note: Since Generating Units do not have different Ramp Rates for Ramping up and down, the Demand pickup rate is ignored.)
Minimum Run Time	Minimum Demand curtailment time
Minimum Down Time	Must be **zero** (Note: Minimum Base Load time is not used because doing so would require the IFM/RTM to link the Generator resource with the Non-Participating Load resource.)
Maximum Daily Start-Ups	Maximum number of daily curtailments
Energy Bid Curve	Must not submit in the DAM or the resource may be dispatched for Energy in the IFM (Bid submitted in the RTM represents offer to curtail Demand associated with the Non-Spinning Reserve ($/MWh).)

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

Segment	Operating Level (MW)	Energy Price $/MWh
1	70	75

Segment	Operating Level (MW)	Energy Price $/MWh
2	150	65
3	200	60
4	250	55
5	300	50
6	340	45
7	375	40
8	400	35
9	450	30
10	475	25
	500	25

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

Segment	Operating Level (MW)	Energy Price $/MWh
1	0	75
2	150	65
3	200	60
4	250	55
5	300	50
6	340	45

Segment	Operating Level (MW)	Energy Price $/MWh
7	375	40
8	400	35
9	450	30
10	475	25
	500	25

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. 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.

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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 5.2.3.4.

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)

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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

Stages	Day-Ahead Timeline	Real-Time Timeline	Activities
1	Up to seven days prior to the Trading Day SC may begin submitting Bids	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	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.
2	10:00 am	T- 75	The DAM and RTM are closed for bid submission CAISO performs any necessary bid generation All market accepted bids with a status

Stages	Day-Ahead Timeline	Real-Time Timeline	Activities
			of Modified or Valid are considered Clean Bids and sent to IFM/RTM to continue processing the markets.

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

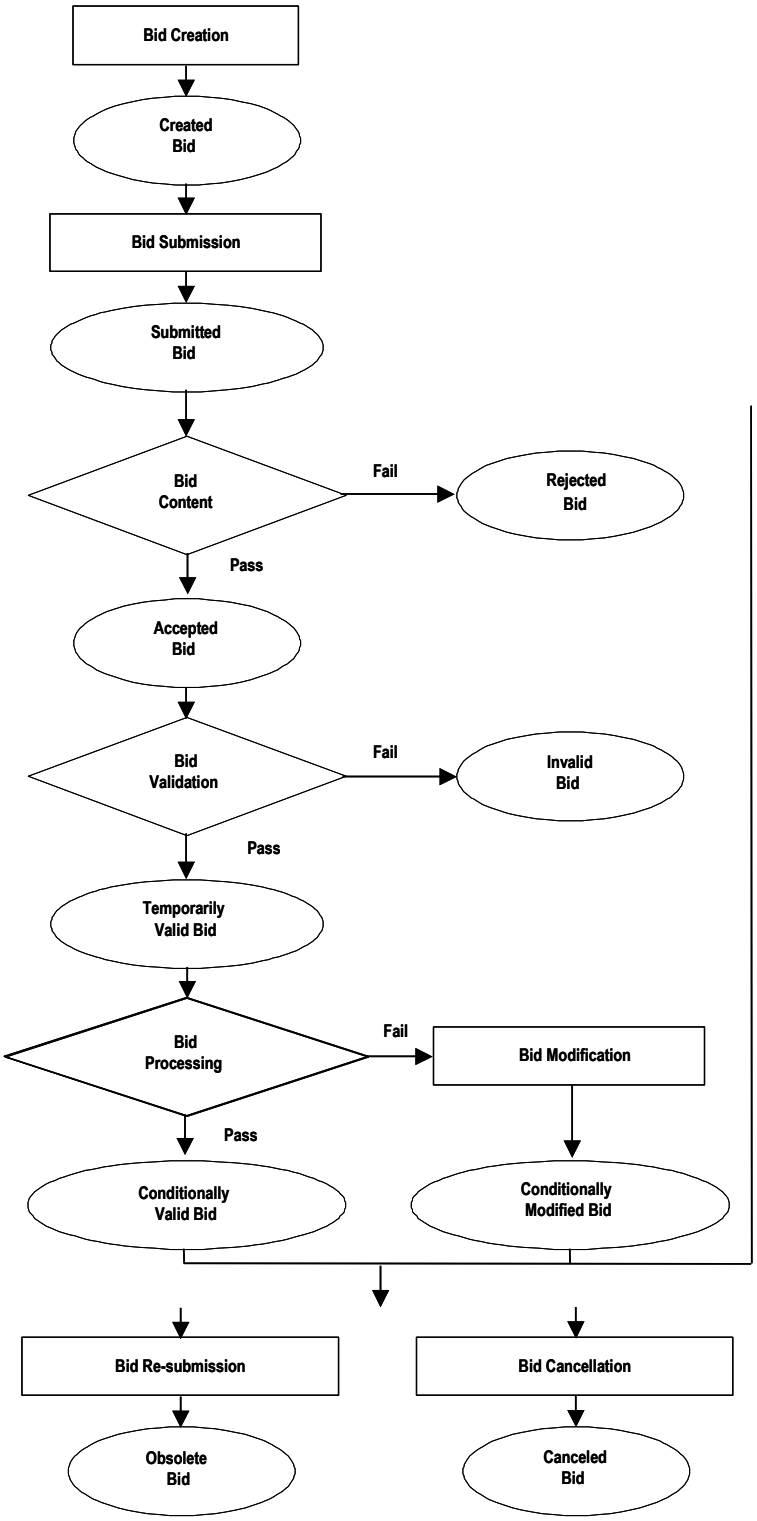
8.2.1 Day-Ahead Market Validation

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



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

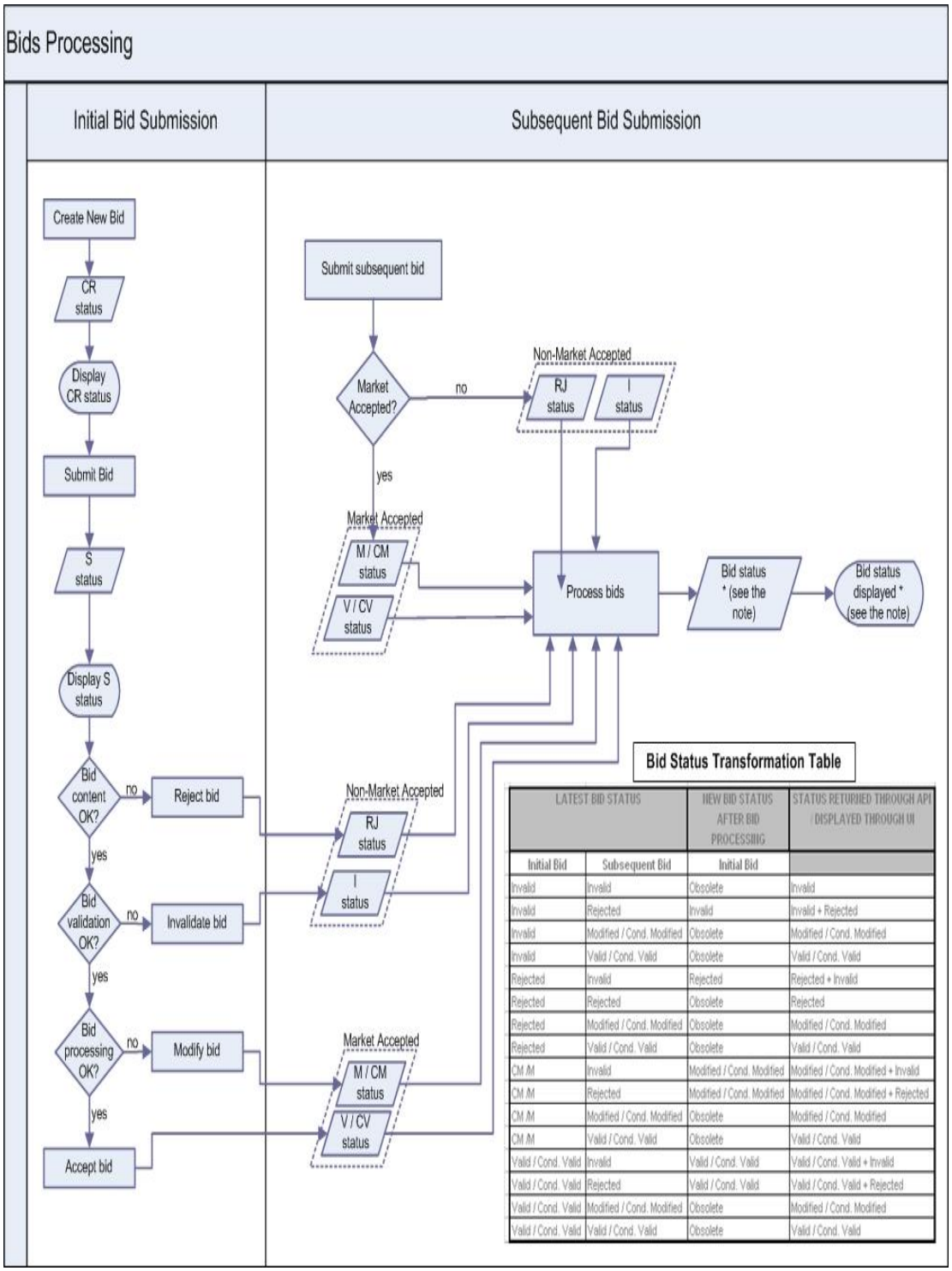
may be modified if it violates any of the processing rules. CAISO analyzes the "Temporarily Valid Bid" to identify any missing Bid components that must be present for the Bid to be valid. CAISO either modifies the Bid for correctness and assigns it a status of "Conditionally Valid Bid" or modifies the 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 Transformation Table

LATEST BID STATUS		NEW BID STATUS AFTER BID PROCESSING	STATUS RETURNED THROUGH API / DISPLAYED THROUGH UI
Initial Bid	Subsequent Bid	Initial Bid	
Invalid	Invalid	Obsolete	Invalid
Invalid	Rejected	Invalid	Invalid + Rejected
Invalid	Modified / Cond. Modified	Obsolete	Modified / Cond. Modified
Invalid	Valid / Cond. Valid	Obsolete	Valid / Cond. Valid
Rejected	Invalid	Rejected	Rejected + Invalid
Rejected	Rejected	Obsolete	Rejected
Rejected	Modified / Cond. Modified	Obsolete	Modified / Cond. Modified
Rejected	Valid / Cond. Valid	Obsolete	Valid / Cond. Valid
CM /M	Invalid	Modified / Cond. Modified	Modified / Cond. Modified + Invalid
CM /M	Rejected	Modified / Cond. Modified	Modified / Cond. Modified + Rejected
CM /M	Modified / Cond. Modified	Obsolete	Modified / Cond. Modified
CM /M	Valid / Cond. Valid	Obsolete	Valid / Cond. Valid
Valid / Cond. Valid	Invalid	Valid / Cond. Valid	Valid / Cond. Valid + Invalid
Valid / Cond. Valid	Rejected	Valid / Cond. Valid	Valid / Cond. Valid + Rejected
Valid / Cond. Valid	Modified / Cond. Modified	Obsolete	Modified / Cond. Modified
Valid / Cond. Valid	Valid / Cond. Valid	Obsolete	Valid / Cond. Valid

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:

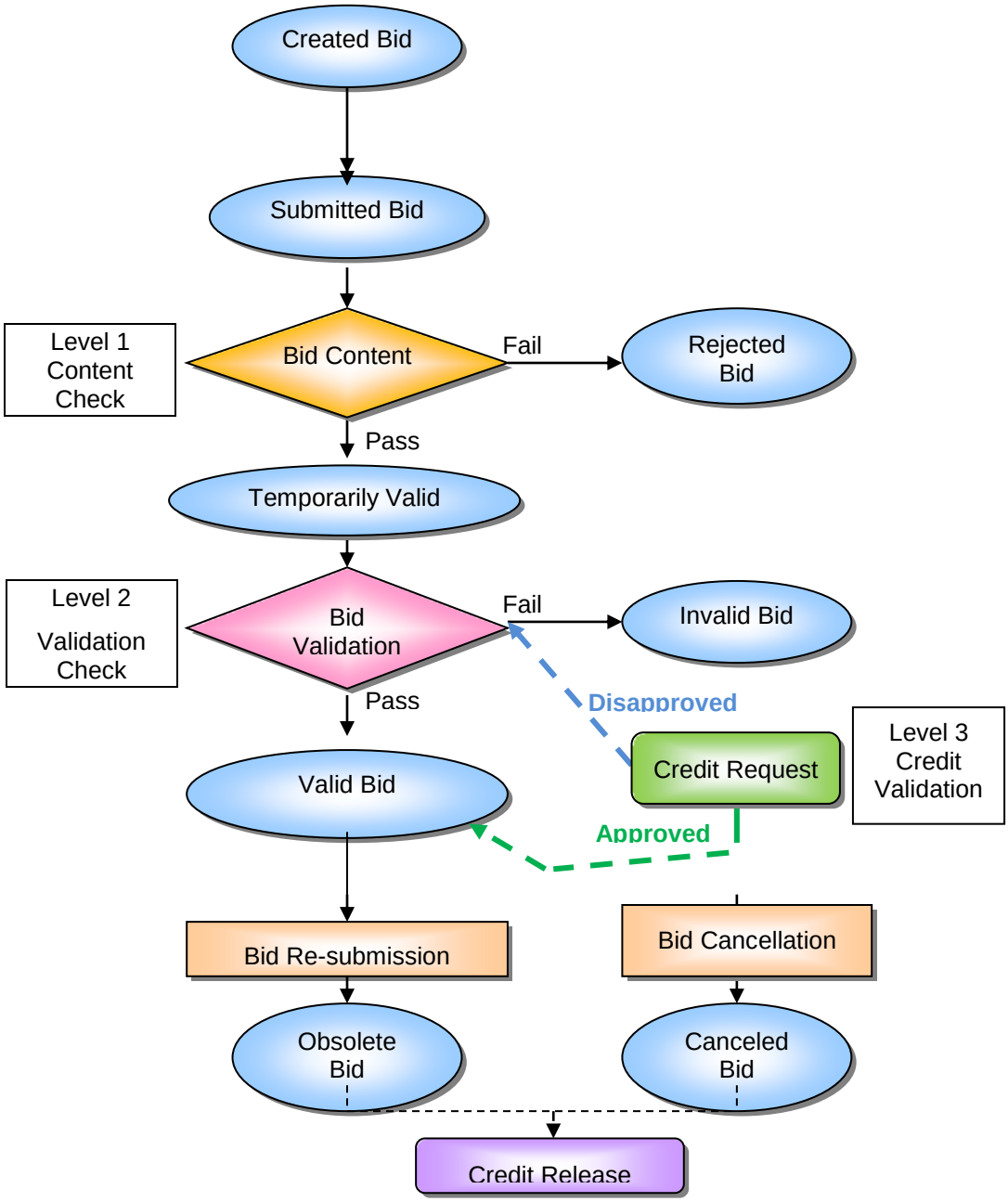
   a) Cancel the Bid, in which case CAISO retains the Bid in the system as a "Cancelled Bid". A cancelled bid will be sent to the Credit Tracking System for a release of the credit.

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



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.

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, which is only available to resources that meet the definition of "Use-Limited" and have fewer than 12 months of LMP data, 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:

    a. Start-Up Energy Cost Curve (registered Start-Up Energy * Energy Price Index).

    b. Start-Up Fuel Cost Curve (registered Start-Up Fuel * Gas Price Index).

    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.

Generated Start-Up Cost Curve = Start-Up Energy Cost Curve + Start-Up Fuel Cost Curve + Greenhouse Gas Start-Up Cost Allowance Curve + Major Maintenance Start-Up Cost Adder + GMC Start-Up Cost Adder.

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

Minimum Load Cost Component

If the Registered Cost Option is applicable, 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.

3. Greenhouse Gas Allowance Minimum Load Cost - the product of the Greenhouse Gas Minimum Load Cost Allowance and the registered Minimum Load (if applicable – see Attachment K for details).

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

   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.

Generated Minimum Load Cost = Minimum Load Fuel Cost + Operation and Maintenance Minimum Load Cost + Greenhouse Gas Allowance Minimum Load Cost + Major Maintenance Minimum Load Cost Adder + GMC Minimum Load Cost Adder.

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.

4. Variable Energy Opportunity Cost, if applicable. See Attachment N of Market Instruments BPM for details on the establishment of Opportunity Cost values for registered energy use limitations.

Generated Energy Bid Curve = energy cost curve + O&M cost + GMC adder + Variable Energy Opportunity Cost

Bid Curve Generation Example

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.

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:

Operating Levels	Average Heat Rate	Gas price index	Operation & Maintenance Cost	Grid Management Charge adder	Variable Energy Opportunity Cost
70	14440	$5.5	$2.80	$0.50	$25
150	11960				
300	10909				
485.17	10366				

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**

3) Generated Energy Curve Calculation

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

Segment 1 – (**53.85** + 2.80 + 0.50 + $25) = **$82.15**

Segment 2 – (**54.22** + 2.80 + 0.50 + $25) = **$82.52**

Segment 3 – (**52.17** + 2.80 + 0.50) = **$80.47**

The resulting Energy Curve is:

70MW – 150MW @ $82.15

150MW – 300MW @ $82.52

300MW – 485.17MW @ $80.47

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

4) Final Generated Energy Curve

70MW - 150MW @ 82.15

150MW – 485.17 MW @ 82.52

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.

5) Minimum Load Cost Calculation

Minimum Load Cost = Minimum Load Fuel Cost + (O&M * Minimum Operating Level) + Greenhouse Gas Allowance Minimum Load Cost + Major Maintenance Minimum Load Cost Adder + 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 resources 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”

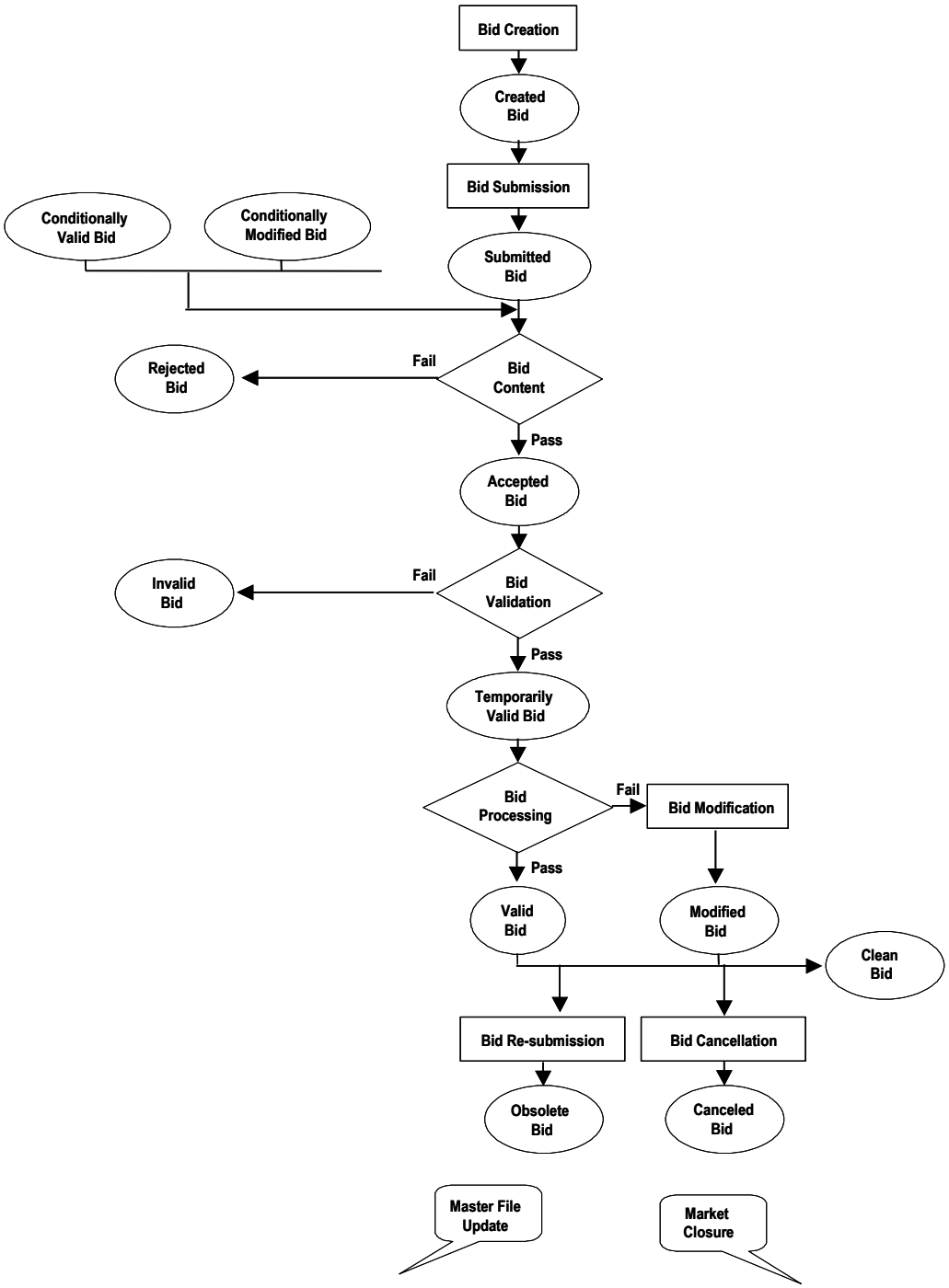
2) CAISO processes the “Temporarily Valid Bid” (using CAISO Market Rules), and either accepts the Bid as submitted, to produce a “Valid Bid” or modifies the Bid to produce a “Modified Bid”.

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”.

Exhibit 8-3: Physical Bid Validation After Final Master File Update and Prior to Market Close



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.

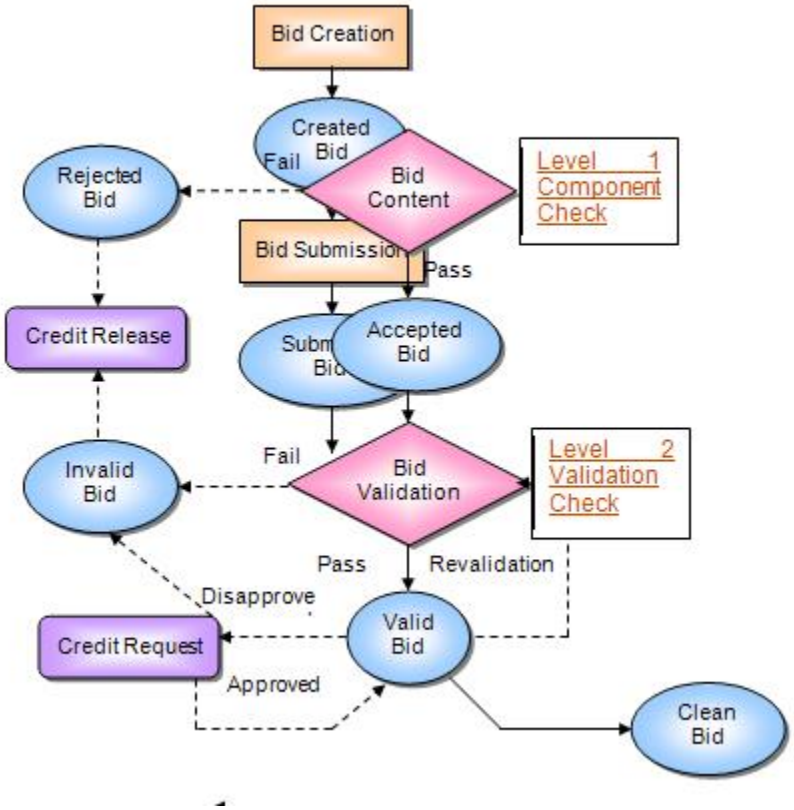
3) The SC reviews the “Valid Bid”, at this time the SC may re-submit the Bid (all validation and Bid processing steps are repeated for the new Bid), or cancel the Bid or allow the Bid to stand.

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”.

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 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.

Exhibit 9-1: Timeline of Inter-SC Trades

Stages	Day-ahead Timeline	Real-time Timeline	Activities
1	Up to seven days prior to the Trading Day Only ISTs for Energy (both PHY and APN) are submitted into the DAM.	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.	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.
2	Between 0600 hours and 11:00 hours of the day prior to the Trading Day.	Between T-180 and T-45 min (the Inter-SC Trade Close Time for IST submission in the RTM)	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 the time.

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 11:00 hours), CAISO notifies SCs if their submitted IST does not have a counterparty. At 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 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

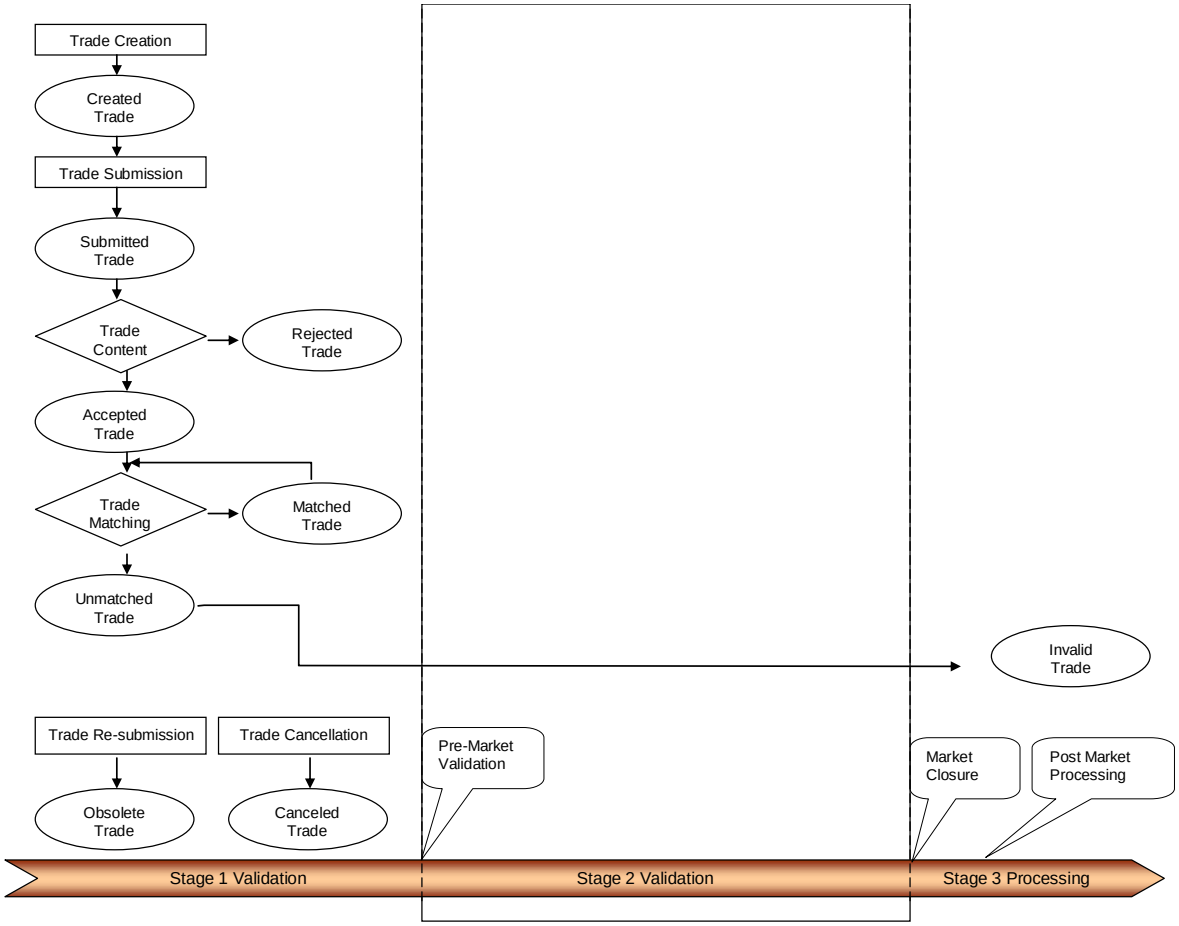
CAISO validates three aspects of the IST:

- 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.

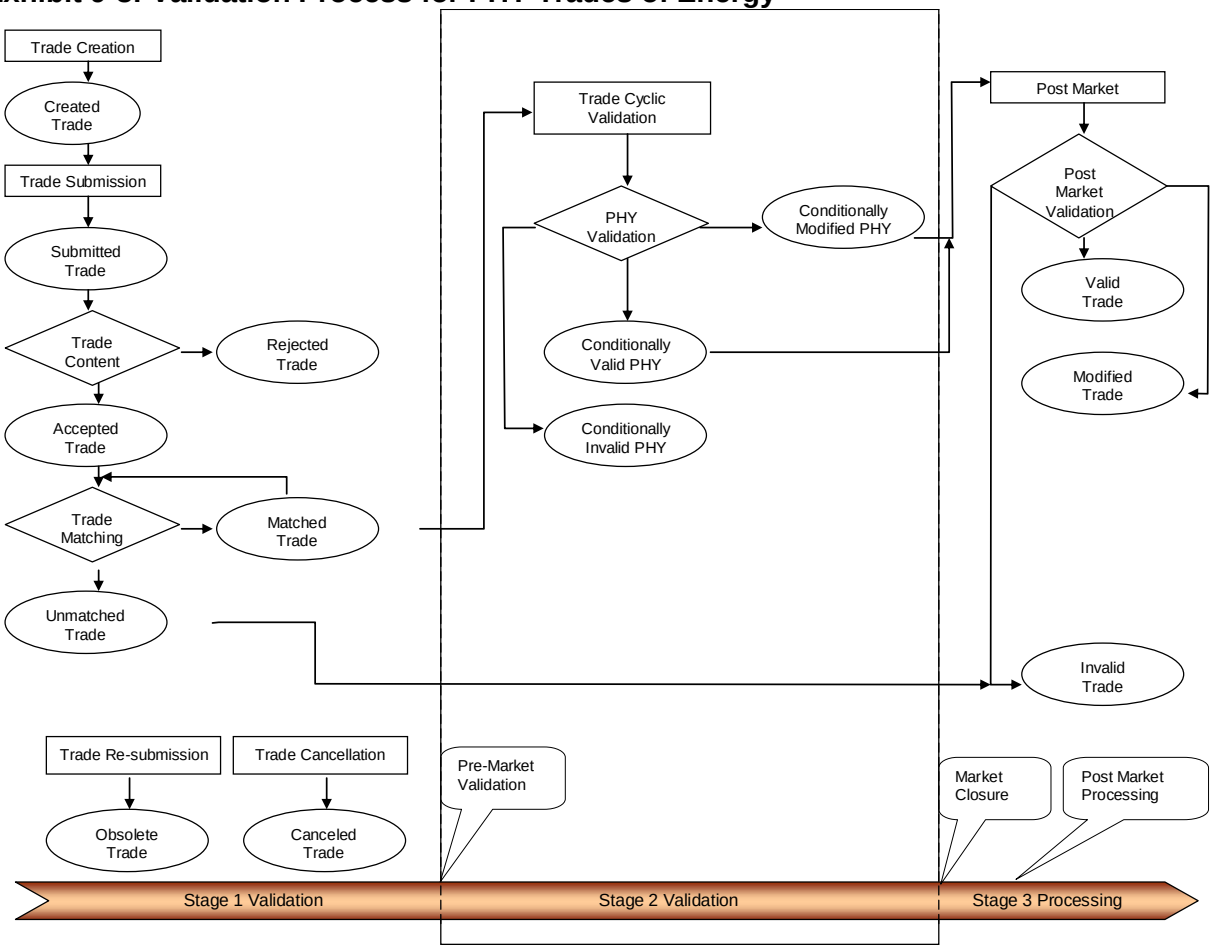
1) At the Inter-SC Trade Close Time, in the event that the capacity of a matched IST exceeds the capacity of the dependent Generating Unit or IST, CAISO adjusts the amount of the matched IST pro-rata. As noted above, the validation process for the RTM also considers the Day-Ahead PHY ISTs at the same 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

Timeline	Activities
RTM Inter-SC Trade Period	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.

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

Timeline	Activities
Submitted as early as 12:00 midnight on the Trading Day up to the close time of T-45.	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.

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

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

Title	Contents
Day Ahead Reports The following Day Ahead reports are available through the Customer Market Results Interface (CMRI).	
Day-Ahead Generation Market Results	Day-Ahead Energy Schedules, Ancillary Services Awards, Load Following and RUC Capacity for Generating Units
Day-Ahead Demand Market Results	Day-Ahead Energy Schedules and Ancillary Services Awards of Participating Loads and Day-Ahead Energy Schedules for Non-Participating Loads
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.

Title	Contents
	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.
Day-Ahead Instructions	Start-Up instructions resulting from the RUC process
Day-Ahead Ancillary Service Market Results	Resource-specific Ancillary Service Awards resulting from the Integrated Forward Market run
Day-Ahead Market Power Mitigation (MPM) Results	Segments of the "new" or mitigated Bid as a result of the Day-Ahead Market Power Mitigation Process (MPM)
Day-Ahead Generation Commodity Prices	Day-Ahead resource-specific prices (for Energy Schedules, Ancillary Services Awards, RUC Awards) of Generating Units
Day-Ahead Demand Commodity Prices	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
Day Ahead Finally Qualified Load Following Capacity	Day-Ahead Finally Qualified Load Following Up and Down Capacity for Metered Subsystems (MSS) resources
Day-Ahead Unit Commitments	Resources that are self-committed or CAISO committed by the IFM or RUC process in the Day-Ahead Market
Day-Ahead Import-Export Commodity Prices	Day-Ahead resource-specific prices (for Energy Schedules, Ancillary Services Awards, RUC Awards) of System Resources
Extremely Long Start Resource Instructions	Startup instructions resulting from the Extremely Long Start Commitment (ELC) process.
Day-Ahead Reliability Must Run (RMR) Dispatches	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
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.
Two Day-Ahead Residual Unit Commitment (RUC) Advisory Schedules	RUC Capacity and RUC advisory awards from the Residual Unit Commitment process run two days ahead. Posted hourly, the following values:

Title	Contents
	• 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. • Advisory Award (RUC Award portion) – this is the portion of the RUC capacity from resources that can potentially receive RUC Availability Payments if awarded during the Day Ahead Market process. For Interties the total RUC Schedule is displayed as the RUC Award product
Real Time Reports The following Real Time reports are available through the Customer Market Results Interface (CMRI).	
Hour-Ahead Scheduling Process (HASP) Market Power Mitigation (MPM) Results	Segments of the "new" or mitigated Bid as a result of the HASP Market Power Mitigation Process (MPM)
Fifteen-Minute Market (FMM) Market Power Mitigation (MPM) Results	Segments of the "new" or mitigated Bid as a result of the FMM Market Power Mitigation Process (MPM)
Hour-Ahead Scheduling Process (HASP) Schedules	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.
Hour-Ahead Scheduling Process (HASP) Schedule Prices	Displays Hour-Ahead Scheduling Process advisory resource-specific prices for the next Trading Hour.
Fifteen-Minute Market (FMM) Schedules	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

Title	Contents
	Cleared and Market will result to equal values as the flexible ramping product can't be self-scheduled.
Fifteen-Minute Market (FMM) Schedule Prices	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.
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.
Real-Time Unit Commitment (RTUC) Advisory Schedules	Reports the 15-minute interval based resource level advisory energy schedules from the real-time 15-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. For VER Resources using the CAISO forecast, the advisory energy schedule is the persistent forecast plus any advisory market dispatch. **Note: Data retention for this report will be a rolling period of five (5) trading days plus the current date.
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. This report should be used to see the forecast generated by CAISO systems in relation to the VER Persistence Market Model.
Real-Time Dispatch (RTD) Schedules	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. For VER resources using the CAISO forecast, the binding energy schedule is the persistent forecast

Title	Contents
	plus any market dispatch.
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. "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. For VER Resources using the CAISO forecast, the advisory energy schedule is the persistent forecast plus any advisory market dispatch. **Note: Data retention for this report will be a rolling period of five (5) trading days plus the current date.
Real-Time Dispatch (RTD) Schedule Prices	Reports the 5-minute interval based resource level binding prices from the real-time 5-minute market runs.
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.
Fifteen Minute Market(FMM) Movement Points	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.
Real Time Dispatch(RTD) Movement Points	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.
Fifteen Minute Market(FMM) Flexible Ramp Price Breakdown	Provide the flexible ramping total price (FRMP) and its BAA level price breakdown, resulting from the FMM/15-minute market outputs.
Real Time Dispatch(RTD) Flexible Ramp Price Breakdown	Provide the flexible ramping total price (FRMP) and its BAA level price breakdown, resulting from the RTD/5-minute market outputs.
Resource Ramp Capacity	Reports hourly resource 15 minute ramp capacity Up/Down for SC from Base Schedule Test Results
Resource Operating Limits	Publish the operation range for Overlapping Resource Aggregation (ORA) resources. Overlapping resource aggregation are multiple aggregate market resources that are registered out of the same set of physical units in a

Title	Contents
	Balancing Authority Area (BAA).
Post-Market Reports The following Post-Market reports are available through the Customer Market Results Interface (CMRI).	
Expected Energy Allocation Details	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
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
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
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

Title	Contents
	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.
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.
Regulation Pay for Performance	Provides the 15-minute performance accuracy values for regulation mileage up (RMU) and regulation mileage down (RMD). In addition, instructed and adjusted regulation mileage data will also be available in this report. Zero values for all these three data elements indicate that either the resource was not awarded regulation or the resource's actual mileage for the interval was zero.
Resource Level Movement	Provide 15-minute and 5-minute resource-level Forecasted Movement (FM) and Uncertainty Movement (UM) for generator and intertie resources, published at TD+1.
CRR Revenue Adjustments	This report provides CRR Holder specific adjustments related to CRR settlements that were adjusted due to DAM flows on binding constraints being lower than the CRR flows on the same constraint as awarded through the CRR allocation and auction process. **Transmission Constraint ID**: Constraint Name from the market. **Constraint Case**: This field contains either Base Case, or the name of the contingency case. **CRR ID**: '0' if the CRR is an obligation type CRR, if an option type CRR then the CRR ID when the CRR was awarded **Hedge Type**: Obligation or Option **CRR Type**: AGG – If an obligation CRR, otherwise MT-Merchant Transmission or MT_TOR-Merchant Transmission TOR **Notional Revenue**: Full CRR value for a CRR Holder without reduction on the constraint **Offset Revenue**: Offset adjustment by hour, by constraint. Positive is a surplus, negative is a deficit **CRR Clawback Revenue**: Clawback amount for a CRR Holder by constraint **Circular Scheduling**: Circular scheduling adjustment amount for a CRR Holder by constraint

Title	Contents
Default Bids Reports The following Default Bids reports are available through the Customer Market Results Interface (CMRI).	
Default Energy Bid Curves	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.
Default RMR Minimum Load & Startup Cost Bid Curves	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.
Greenhouse Gas Bid Cap	Provides the daily greenhouse gas maximum cost value ($/mwh) of EIM participating resources. This report is available to the scheduling coordinator of the resource.
Daily Electricity Price Index	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.
Daily Electricity Price Index (EPI)	Provides resource level daily EPI, based on Wholesale or Retail Electric Region type, which is calculated on daily basis.
Actual Limitation Values	Provides actuals (scheduled) starts (including MSG transitions), run-hours and energy output for use-limited each resource.
Resource Opportunity Costs	Provides modeled opportunity costs results for each resource on monthly and daily basis depending on OC Used Flag (Y/N)
Default Commitment Costs	This daily report includes the latest default commitment costs that includes Minimum Load Costs, Start-Up Costs, and Transition Costs. This report is published three times daily approximately at 2:30 AM, 9:00 AM, and 10:00 PM. DAM and RTM will use the latest default commitment costs that are available at the time when these markets start to run. If no payload consumption failure by CMRI, DA will use the payload broadcasted at 9:00 AM and RTM will use the payload broadcasted at 10:00 PM.

Title	Contents
	This applies to EIM and non-EIM resource types.
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.
Forecast Reports The following Forecast reports are available through the Customer Market Results Interface (CMRI).	
Variable Energy Resource Forecast	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.
Reference Reports The following Reference reports are available through the Customer Market Results Interface (CMRI).	
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

Title	Contents
	• PrimaryFlowgate identifier • SecondaryFlowgate 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
Energy Imbalance Market Reports The following Energy Imbalance Market reports are available through the Customer Market Results Interface (CMRI).	
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).
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.
Load Base Schedules	Reports the base schedules for load resources under the real-time markets
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 Sufficiency 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

Title	Contents
	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.
EIM After-the-fact Interchange Schedules	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.
EIM Bid Capacity	This report publishes the hourly high and low percentile of interchange schedule deviation for the BAA EIM Entity.
EIM Bid Capacity	Reports hourly interchange schedule deviation. System will report on the new calculated bid capacity percentage for the next month. System will report high and low percentile of import histogram for each EIM BAA and ISO for each hour (24 hours) for the applicable month. The EIM entity who get the base schedule test results shall see the percentage. Ex: PAC, NVE
Resource Operating Limits	Publish the operation range for Overlapping Resource Aggregation (ORA) resources. Overlapping resource aggregation are multiple aggregate market resources that are registered out of the same set of physical units in the Energy Imbalance Market (EIM) Balancing Authority Area (BAA).

Phase Shifter Reports

The CAISO controlled grid includes phase shifter transformers that enable the CAISO as the balancing authority area to monitor and adjust the power flow on the CAISO controlled grid. Phase-shifting transformers are designed to ensure the reliable and secure operation of the grid is maintained. Phase-shifting transformers help control the power flow through transmission lines by changing the phase angle between the input voltage and the output voltage of the transmission lines. The CAISO market systems model the phase-shifting transformers in its congestion management and produces a least cost security

Title	Contents
constrained dispatch phase-shifting transformer tap control and manages the power flow directly. The CAISO market systems can optimize phase-shifting transformer tap control by including the tap position movement impact on the transmission flow on a particular constraint.	
Tap Position	This report present the PST devices optimized PST tap position for IFM, RTUC, RTD for binding intervals for the each market time horizon, in the same manner as resource.
Advisory Tap Position	This report present the PST devices optimized PST tap position for RTUC, RTD for advisory intervals for the each market time horizon, in the same manner as resource.
Contingency Dispatch Tap Position	This report present the PST devices optimized PST tap position for RTCD/RTDD for binding intervals for the each market time horizon, in the same manner as resource.
Gas Burn Reports The following Gas Burn reports are available to gas companies through the Customer Market Results Interface (CMRI). These reports calculate and present gas burn estimates to gas companies serving electric generation located within the CAISO BAA. This functionality provides timely information to the gas companies for their use to manage their respective system operations. Gas burn estimate data are calculated using IFM and RUC results for Day Ahead and Two Day Ahead (Daily) reports and using RTUC results for Real Time reports. The reports are published immediately following completion of the applicable market and burn values are displayed in MMcf. The Daily reports show hourly values for each electric market day and the Real Time reports show fifteen minute values for available RTPD intervals.	
Gas Burn Detail	CMRI shall consume and publish Gas burn data in MMcf for Resources that belong to Gas Companies on; • hourly basis for the entire next day for IFM and RUC pass • hourly basis for the entire day after tomorrow (D+2) for IFM and RUC pass 15 minute basis for the RTPD binding and STUC advisory intervals
Gas Burn Summary	CMRI shall consume and publish Gas burn summary data in MMcf for various levels like Gas Company, Service Area, Forecast Zone, Transmission Zone, Gas Meter on; • hourly basis for the entire next day for IFM and RUC pass • hourly basis for the entire day after tomorrow (D+2) for IFM and RUC pass

Title	Contents
	15 minute basis for the RTPD binding and STUC advisory intervals

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:

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

Portal:

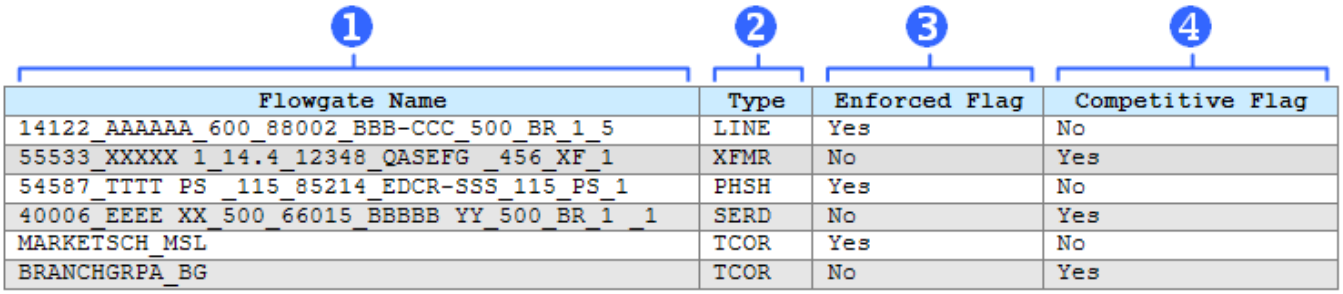
Title	Contents
Day-Ahead Load Distribution Factors	Displays the load distribution factors used in the Day-Ahead Market.
Shift Factors	Displays the complete list of shift factors for all binding constraints in the IFM, HASP, and RTED markets.
Transmission Limits	Displays the transmission limits for all critical constraints in the IFM, HASP, and RTED markets. Critical constraints are classified as those

Title	Contents
	constraints for which in each respective market run are at or approaching their limit.

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:



Flowgate Name	Type	Enforced Flag	Competitive Flag
14122_AAAAAA_600_88002_BBB-CCC_500_BR_1_5	LINE	Yes	No
55533_XXXXX 1_14.4_12348_QASEFG _456_XF_1	XFMR	No	Yes
54587_TTTT PS _115_85214_EDCR-SSS_115_PS_1	PHSH	Yes	No
40006_EEEE XX_500_66015_BBBBB YY_500_BR_1 _1	SERD	No	Yes
MARKETSCH_MSL	TCOR	Yes	No
BRANCHGRPA_BG	TCOR	No	Yes

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

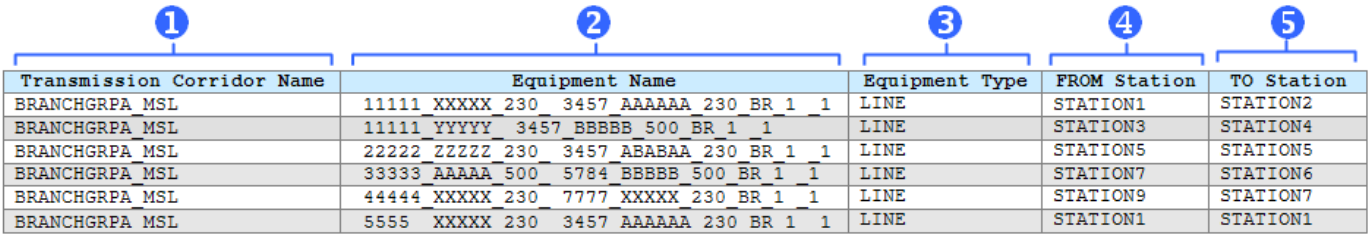
#	Attribute	High-Level Description
	Trade Date PG	Date on when the trade transaction occurs within the market
	Market PG	Type of market in which the nomogram constraints applies to: ▪ Post Day-Ahead ▪ Pre Day-Ahead

1	Flowgate Name	The unique alphanumeric identifier name of a flowgate
2	Type	The equipment classification of the flowgate, as follows: ▪ LINE (Individual transmission line between two sta ions) ▪ XFMR (Transformer in station transforming from one voltage to another) ▪ PHSH (Phase shifter controlling flow) ▪ SERD (eries dev ce capacitor, reactor) ▪ TCOR (Transmission Corridor)
3	Enforced Flag	The indicator specifying if the flowgate is enforced or not (Yes/No)
4	Competitive Flag	The indicator specifying if the flowgate is competitive (Yes/No)

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:



1 Transmission Corridor Name	2 Equipment Name	3 Equipment Type	4 FROM Station	5 TO Station
BRANCHGRPA_MSL	11111_XXXXX_230_ 3457_AAAAAA_230_BR_1 _1	LINE	STATION1	STATION2
BRANCHGRPA_MSL	11111_YYYYY_ 3457_BBBBB_500_BR_1 _1	LINE	STATION3	STATION4
BRANCHGRPA_MSL	22222_ZZZZZ_230_ 3457_ABABAA_230_BR_1 _1	LINE	STATION5	STATION5
BRANCHGRPA_MSL	33333_AAAAA_500_ 5784_BBBBB_500_BR_1 _1	LINE	STATION7	STATION6
BRANCHGRPA_MSL	44444_XXXXX_230_ 7777_XXXXX_230_BR_1 _1	LINE	STATION9	STATION7
BRANCHGRPA_MSL	5555 XXXXX 230 3457 AAAAAA 230 BR 1 1	LINE	STATION1	STATION1

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

#	Attribute	High-Level Description
	Trade Date PG	Date on when the trade transaction occurs within the market
	Market PG	Type of market in which the transmission corridor constraints applies to: ▪ Post Day-Ahead ▪ Pre Day-Ahead
1	Transmission Corridor Name	The unique alphanumeric identifier name of a transmission corridor
2	Equipment Name	The unique alphanumeric identifier for an equipment comprising a transmission corridor

3	Equipment Type	The classification of the equipment, as follows: ▪ LINE (Ind vid transmission line between two stations) ▪ XFMR (Transformer in station transforming from one voltage to anothe ▪ PHSH (Phase shifter controlling flow) ▪ SERD (Series device capacitor, reactor)
4	FROM Station	This refers to the name of station at the “FROM” end of the line
5	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:

1 Nomogram Name	2 Enforced Flag	3 Competitive Flag	4 Constraint Type	5 Curve ID	6 Segment ID	7 Effective Start Datetime	8 Effective End Datetime
T-XXX_SALXX_NG_SUM	Yes	Yes	LE	1	1	mm/dd/yyyy hh:mm:ss AM/PM	mm/dd/yyyy hh:mm:ss AM/PM
BBBB_YYYYYY_NG	No	Yes	LE	1	1	mm/dd/yyyy hh:mm:ss AM/PM	mm/dd/yyyy hh:mm:ss AM/PM
2222220-ABAB-OLPOL-LOS9	Yes	Yes	GE	1	1	mm/dd/yyyy hh:mm:ss AM/PM	mm/dd/yyyy hh:mm:ss AM/PM
X-111 AAAAAA_NG_SUM	No	No	GE	1	1	mm/dd/yyyy hh:mm:ss AM/PM	mm/dd/yyyy hh:mm:ss AM/PM
PAULX_115_NM	Yes	No	LE	1	1	mm/dd/yyyy hh:mm:ss AM/PM	mm/dd/yyyy hh:mm:ss AM/PM
ZZZZZZ_TKs_QAFLG_NG	No	No	LE	1	1	mm/dd/yyyy hh:mm:ss AM/PM	mm/dd/yyyy hh:mm:ss AM/PM
SC_OOOOO_XYXYXYX_NG	Yes	Yes	GE	1	1	mm/dd/yyyy hh:mm:ss AM/PM	mm/dd/yyyy hh:mm:ss AM/PM

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

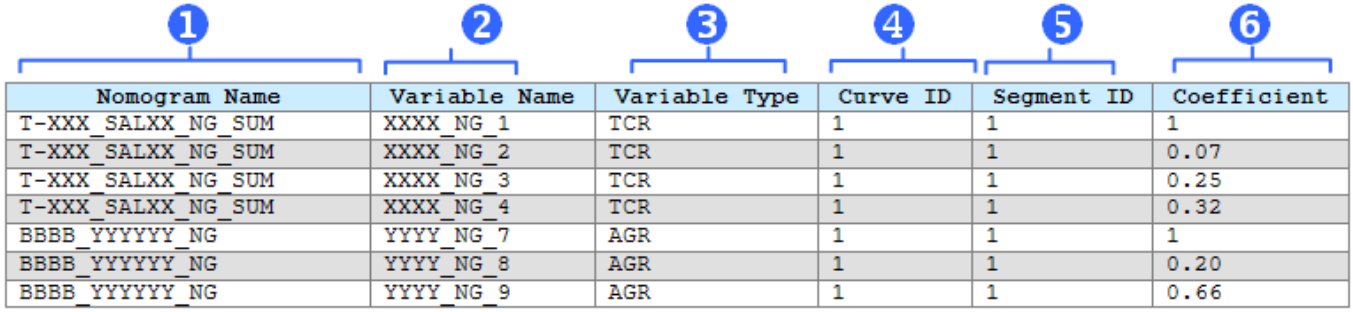
#	Attribute	High-Level Description

	Trade Date PG	Date on when the trade transaction occurs within the market
	Market PG	Type of market in which the nomogram constraint enforcements applies to: ▪ Post Day-Ahead ▪ Pre Day-Ahead
1	Nomogram Name	The unique alphanumeric identifier name of a nomogram
2	Enforced Flag	The indicator specifying if the nomogram is enforced or not (Yes/No)
3	Competitive Flag	The indicator specifying if the nomogram is competitive (Yes/No)
4	Constraint Type	The classification of the constraint, as follows: ▪ LE (Less or equal) ▪ GE (Greater or equal)
5	Curve ID	The numeric identifier of the Curve. There can be up to N number of Curves defined per transmission corridor
6	Segment ID	The numeric identifier of the Segment of the Curve. There can be up to N number of segments per Curve
7	Effective Start Datetime	The effective start datetime of the nomogram enforcement (Pacific)
8	Effective End Datetime	The effective end datetime of the nomogram enforcement (Pacific)

10.2.4 Nomogram Constraint Definitions

Exhibit 10-2.5: Nomogram Constraint Definitions

Report Description	Displays the complete list of defined nomogram constraints 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:



Nomogram Name	Variable Name	Variable Type	Curve ID	Segment ID	Coefficient
T-XXX_SALXX_NG_SUM	XXXX_NG_1	TCR	1	1	1
T-XXX_SALXX_NG_SUM	XXXX_NG_2	TCR	1	1	0.07
T-XXX_SALXX_NG_SUM	XXXX_NG_3	TCR	1	1	0.25
T-XXX_SALXX_NG_SUM	XXXX_NG_4	TCR	1	1	0.32
BBBB_YYYYYY_NG	YYYY_NG_7	AGR	1	1	1
BBBB_YYYYYY_NG	YYYY_NG_8	AGR	1	1	0.20
BBBB_YYYYYY_NG	YYYY_NG_9	AGR	1	1	0.66

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

#	Attribute	High-Level Description
	Trade Date PG	Date on when the trade transaction occurs within the market
	Market PG	Type of market in which the nomogram constraints applies to: ▪ Post Day-Ahead ▪ Pre Day-Ahead
1	Nomogram Name	The unique alphanumeric identifier name of a nomogram
2	Variable Name	The unique alphanumeric identifier of the nomogram variable
3	Variable Type	The variable type, representing flow across a transmission corridor (TCR), aggregated generator (AGR), or generator (G)
4	Curve ID	The numeric identifier of the Curve. There can be up to N number of Curves defined per nomogram
5	Segment ID	The numeric identifier of the Segment of the Curve. There can be up to N number of segments per Curve.
6	Coefficient	The participation factor of the variable in the nomogram inequality

10.2.5 Transmission Contingencies

Exhibit 10-2.6: Transmission Contingencies

Report Description	Displays the complete list of transmission contingencies 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:

Contingency Title	Enforced Flag	TAC Area	Equipment Station	Equipment Voltage	Equipment Name
mTC1-SUNNY-XXXXX	Yes	TAC-1	STATION1	115	11111_XXX AAA1_115_41517_YYYYYY_115_BR_1 _1
mTC1-SUNNY-XXXXX	Yes	TAC-1	STATION1	115	22222_YYY BBB _16.0_41712_QQQ BQA1_115_XF_1
mTC1-SUNNY-XXXXX	Yes	TAC-1	STATION2	230	33333_PPPPPP_115_21554_BABABABA_115_BR_1 _1
mTC2-CLOUDY-MMMMM-1	Yes	TAC-2	STATION1	115	44444_LLLLL PT_115_20273_MMMMM C_115_BR_1 _1
mTC2-CLOUDY-MMMMM-1	Yes	TAC-2	STATIONA	230	55555_EEEEE PT_115_54128_KKKKK C_115_BR_1 _1
mTC3-WWWWW-DDDDDD-3	Yes	TAC-3	STATIONB	115	66666_ABDCE PT_115_23244_MMMMM C_115_BR_3 _1
mTC3-WWWWW-DDDDDD-3	Yes	TAC-3	STATIONC	230	99999 SSSPP PT 115 33244 XXXXX C 115 BR 3 1

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

#	Attribute	High-Level Description
	Trade Date PG	Date on when the trade transaction occurs within the market
	Market PG	Type of market in which the transmission contingencies applies to: ▪ Post Day-Ahead ▪ Pre Day-Ahead
1	Contingency Title	The unique alphanumeric identifier of the contingency name
2	Enforced Flag	The indicator specifying if the contingency is enforced or not (Yes/No)
3	TAC Area	This represents the zone at which the contingency is defined in
4	Equipment Station	The substation where the outaged equipment is located at

5	Equipment Voltage	The voltage level of the outaged equipment (e.g. 115, etc)
6	Equipment Name	The alphanumeric identifier of the outaged equipment

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:

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

Attributes

Listed below are the data elements contained in this report.

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

Attribute	High-Level Description
GMT Interval	Start time of the time interval (GMT)
DLAP	Default Load Aggregation Point. Used to select nodes within a particular DLAP.
Node	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"
LDF	The load distribution factor used in the Day-Ahead Market for the node and interval.

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.

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

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

Attribute	GMT Interval	Constraint Name	Constraint Cause	Curve ID	Segment ID	Node Name	Shift Factor
FLOWGATE	4/13/2012 11:00:00 AM	31512_BIG BEN2_115_31516_WYANDJT2_115_BR_1 _2	Base Case			NDE_1_N001	0.038230803
FLOWGATE	4/13/2012 11:00:00 AM	31512_BIG BEN2_115_31516_WYANDJT2_115_BR_1 _2	Base Case			NDE_1_N002	0.092708223
FLOWGATE	4/13/2012 11:00:00 AM	31512_BIG BEN2_115_31516_WYANDJT2_115_BR_1 _2	Base Case			NDE_1_N003	0.027463121
FLOWGATE	4/13/2012 11:00:00 AM	31512_BIG BEN2_115_31516_WYANDJT2_115_BR_1 _2	Base Case			NDE_1_N004	0.027463121
FLOWGATE	4/13/2012 11:00:00 AM	31512_BIG BEN2_115_31516_WYANDJT2_115_BR_1 _2	Base Case			NDE_1_N005	0.027463121
NOMOGRAM	4/13/2012 11:00:00 AM	RAVENSWDSANMAT_NG_1	Base Case	1	1	NDE_1_GN10	0.038230803
NOMOGRAM	4/13/2012 11:00:00 AM	RAVENSWDSANMAT_NG_1	Base Case	1	1	NDE_1_GN11	0.092708223
NOMOGRAM	4/13/2012 11:00:00 AM	RAVENSWDSANMAT_NG_1	Base Case	1	1	NDE_1_GN12	0.027463121
NOMOGRAM	4/13/2012 11:00:00 AM	RAVENSWDSANMAT_NG_1	Base Case	1	1	NDE_1_GN13	0.027463121
NOMOGRAM	4/13/2012 11:00:00 AM	RAVENSWDSANMAT_NG_1	Base Case	1	1	NDE_1_GN14	0.027463121

Attributes	Listed below are the data elements contained in this report. Note: the reports are contained in files accessed from the CAISO Portal.

Attribute	High-Level Description
Constraint Class	Indicates whether the constraint is a Flowgate (branch or branch group), Nomogram, or Intertie.
GMT Interval	Start time of the time interval (GMT)
Constraint Name	Name of transmission element, including interchanges, branches, branch groups, and nomograms.
Constraint Direction	The direction in which the constraint is binding: "From-To" or "To-From" for Flowgates; "Import" or "Export" for Interties; "LE" (Less or Equal) or "GE" (Greater or Equal) for Nomograms.
Constraint Type	For ITC constraints only, the type of the ITC constraint: "Energy/AS" for Energy/AS scheduling limit; "AS" for AS scheduling limit.
Constraint Cause	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.
Curve ID	For Nomograms, indicates which curve ID the limit applies to.
Segment ID	For Nomograms, indicates which segment ID the limit applies to.
Node Name	The unique alphanumeric identifier of the Node name
Shift Factor	The power flow contribution from an injection at the Node on the constraint in the specified direction during the specified time interval.

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:

GMT Interval	Constraint Name	Direction	Constraint Cause	Curve ID	Segment ID	Limit
4/13/2012 11:00:00 AM	CASCADE_ITC	Export	Base Case			300
4/13/2012 11:00:00 AM	SCE_PCT_IMP_BG	Import	Base Case			2000
4/13/2012 11:00:00 AM	34112_EXCHEQUR_115_34116_LE GR		Base Case			50
4/13/2012 11:00:00 AM	RAVENSWDSANMAT_NG_1		Base Case	1	1	300

Attributes

Listed below are the data elements contained in this report.

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

Attribute	High-Level Description
GMT Interval	Start time of the time interval (GMT)
Constraint Name	Name of transmission element, including interchanges, branches, branch groups, and nomograms.
Direction	For branch groups and interchanges, indicates whether the limit is in the import or export direction.
Constraint Case	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.
Curve ID	For nomograms, indicates which curve ID the limit applies to.
Segment ID	For nomograms, indicates which segment ID the limit applies to.
Limit	The actual limit used on the transmission element for the market and interval.

10.3 SIBR Reports

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

Exhibit 10-3.1: SIBR Report Content

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

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

Reports	Policy
Reports listed in section 10.1, except the Conformed Dispatch Notice report.	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.
Conformed Dispatch Notice report.	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.
Reports listed in section 10.2	Data will be available for 90 calendar days after it was published.
Reports listed in section 10.3	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.

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

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

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 mode[15]), 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[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,

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;

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

[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:
http://www.caiso.com/Documents/2330C.pdf

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

[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.

This reports 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, 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 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.

Hourly RTM LAP Prices - Posts daily for T-1, the LAP prices with hourly granularity from Real Time Market Run.

Flexible Ramp Requirements Inputs - Flexible Ramp Requirements Inputs - This report contains balancing authority area-level 15-minute interval data published at T-75', T-55' and T-40' for both "UP" and "DOWN" Ramp Types for the following:

- Requirement Amount
- Credit
- Net Import Capability
- Net Import Capability
- Diversity Benefit

Competitive Solicitation Process Offer - The Reliability Service Initiative (RSI) is a multi-year effort to address the ISO's rules and processes surrounding resource adequacy (RA) resources.

OASIS shall publish a new report for finalized bids into the competitive solicitation process for annual, monthly and intra-monthly offer period.

- This data will be posted on a rolling five-quarter delay that starts on the period offer start date. (end of 15 months after last day of the month).

- Supplier offers shall be described by generation technology type, MW quantity, price, RA capability (system, flexible, local), and competitive solicitation process offered.
- Offers shall be aggregated in the event less than three resources are in a single generation technology type.

The Offer Data is only downloadable to XML and CSV.

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 = hourly TTC – CBM - total TRM - AS from imports - scheduled net energy from imports/exports - 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.

Net EIM Transfer Limits - This report broadcast the net EIM transfer limits for both the import and/or export directions based on the following rules:
- Flexible Ramping Sufficiency Test (FRST) failure for RTPD and RTD intervals will only report the direction of FRST failure.
- EIM BAA contingency event (RTD only), occurs for both import and export direction.
- EIM Operator manually locks EIM transfer level via BAAOP (RTPD, RTD), occurs for both import and export directions.~~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 cacpacity 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.

Expected Energy – Lists after-the-fact Energy accounting, per Energy type. Posted daily at T+1, in MWh for ISO total.

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).

Convergence Bidding Aggregate Awards - Posts Day Ahead CAISO aggregate Virtual Bidding Awards for Energy for Supply and Demand. Publishes with the Day Ahead Market results.

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.

Zonal uplift – This report contains monthly uplift payments to resources. The report identifies uplift payments by transmission zone, day, and uplift category, i.e. charge code. For purposes this report, a transmission zone within the CAISO shall reflect the Transmission Access Charge Area of each Participating Transmission Owner. The ISO will publish this report 18 days after the end of each trade month plus 18 calendar days, and again 80 days after the end of each trade month plus 80 calendar days. Please refer to the Configuration Guides posted on the BPM Settlements and Billing page to obtain the charge code descriptions included on this report.

Resource-Specific Uplift – This report contains the uplift paid to each resource by uplift category and aggregated across a trade month. The ISO will publish this report 80 days after the end of each trade month. Please refer to the Configuration Guides posted on the BPM Settlements and Billing page to obtain the charge code descriptions included on this report.

Operator-Initiated Commitment – This report contains monthly information reflecting operator commitments that includes the following information

- Commitment size (MW),
- Transmission zone,
- Commitment reason. Please refer to Market Operations Appendices BPM section K.1 Table 2 for the reason code mapping.
- Commitment start time of each operator-initiated commitment.

For RUC commitments, the reason will be as “system wide capacity” and clarified reason would be “Optimization” since the commitment for RUC is coming from the market optimization. The ISO will publish report 25 days at the end of each trade month.

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

CRR Aggregated Revenue Adjustment Data – This report provides aggregated CRR Holder adjustments related to CRR settlements that were adjusted due to DAM flows on binding constraints being lower than the CRR flows on the same constraint as awarded through the CRR allocation and auction process.

Transmission Constraint ID: Constraint Name from the market

Constraint Case: This field contains either “Base Case”, or the name of the contingency case.

Notional Revenue: Full CRR value for all CRR Holders without reduction on the constraint.

Offset Revenue: The total offset adjustment on a constraint, for a trade day and hour. A positive value is a surplus and a negative value is a deficit.

CRR Revenue Adjustments Details – This report will provide data at the CRR ID level with the exception of the Offset Revenue amount. The offset revenue amount is at the hourly constraint level, the same as in the CRR Revenue Adjustment report. The CRR ID reflected in the below report is the netted MW amount based on netted source/sink locations as described in section 17 of the BPM for CRRs. For example, if an entity holds CRR1 from A to B for 10MW and CRR2 from B to A for 5MW for the same period the below report would reflect CRR1 from A to B for 5MW.

Transmission Constraint ID: Constraint Name from the market.

Constraint Case: This field contains either “Base Case” or the name of the contingency case

CRR ID: The CRR ID is the CRR ID associated with netted source/sink methodology as described in section 17 of the BPM for CRRs. If there are no CRRs to net then it will be the CRR ID as originally awarded.

Hedge Type: Obligation or Option

CRR Type: Possible CRR types include; LSE-Load Serving Entity, AUC-Auction, LSE_LMT-LSE Load Migration Flow, LMT_CNT-Load Migration Counter-flow, LSE_THCNT-LSE Trading Hub Counter-flow, MT-Merchant Transmission or MT_TOR-Merchant Transmission TOR. The CRR type will be the value associated with the netted CRR as listed under CRR ID above.

Notional Revenue: Full CRR value for this CRR ID

Offset Revenue: Offset adjustment by hour, by constraint. This value is not at the CRR ID level. Positive is a surplus, negative is a deficit.

CRR Clawback Revenue: Clawback amount for a CRR ID by constraint

Circular Scheduling: Circular scheduling adjustment amount for a CRR Holder by constraint

Derate Factor: This value will be '1' unless there is a derate associated with MT_TOR type CRRs

CRR Award MW: This value is the netted MW based on source/sink locations as described in section 17 of the BPM for CRRs.

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.

[18] This listing does NOT include Load Resources – this is covered by the Load Aggregation Point listing.

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.

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:

http://www.caiso.com/participate/Pages/ApplicationAccess/Default.aspx

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.

Section 4.6.4 of the tariff requires resource information submitted to master file to "be an accurate reflection of the design capabilities of the resource and its constituent equipment when operating at maximum sustainable performance over Minimum Run Time, recognizing that resource performance may degrade over time." The design capability refers to how the resource and its equipment was designed to operate under normal conditions, subject to whatever performance degradation the resource has experienced over its lifespan.

Updates can be made 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:

Spreadsheet Tab	Contents
Instruction	Contains report details
Definition-GRDT	Link to blank template on CAISO website
Code	Blank
RESOURCE	Resource data
RAMPRATE	Resource ramp rate
HEATRATE	Resource heat rate
STARTUP	Resource start-up data
FORBIDDEN OPR REGION	Resource forbidden operating region
REGULATION	Resource regulation range
REG RAMP	Resource regulation ramp rate
OP RES RAMP	Resource operating reserve ramp rate
MSG_CONFIG	MSG Configuration detail
TRANSITION	Details of transitions between configurations
CONFIG_RAMP	Configuration ramp rate
CONFIG_HEAT	Configuration heat rate
CONFIG_STRT	Configuration start-up detail
CONFIG_REG	Configuration regulation range
CONFIG_RREG	Configuration regulation ramp rate
CONFIG_ROPR	Configuration operating reserve ramp rate
GEN_RES_AGGR	Child Resources of Aggregate Resource

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 describe in the following table in the order they appear in the GRDT. Non-modifiable fields are described in the next section.

RDT Column Name	Unit	Definition	Business Rule
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 (negative) withdrawn from the grid when unit is charging 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

RDT Column Name	Unit	Definition	Business Rule
MIN_ON (Minimum On Time)	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 RDRR, must be <= 60
MAX_ON (Maximum On Time)		*This data element is not used - Market software does not reference this data element.*	
MIN_OFF (Minimum Off Time)	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 (Maximum Startups Per Day)	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
MKT_MAX_STRT (Market Maximum Startups Per Day)		*This data element is not currently used.*	

RDT Column Name	Unit	Definition	Business Rule
MIN_LOAD_COST (Minimum 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
ML_COST_BASIS_TYPE (Minimum Load 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 that do not have at least twelve consecutive months of LMPs or have not reached the start of the second month after the end of the twelve months of consecutive LMPs 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 (Start-Up 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 that do not have at least twelve consecutive months of LMPs or have not reached the start of the second month after the end of the twelve months of consecutive LMPs 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
MAX_PUMP (Maximum Pump Capacity)	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
MIN_PUMP_CST (Pumping Minimum Cost)	$/hour	The hourly cost of operating a hydro pump, expressed in $/hour	• Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP
PUMPING_FACTOR (Pumping Factor)	numeric	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)	starts/day	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

RDT Column Name	Unit	Definition	Business Rule
PUMP_MIN_UP_TM (Pump Minimum Up Time)	minutes	The minimum time that a Pumped Storage Hydro Resource must stay in pumping mode after switching to that mode.	• Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP
PUMP_MIN_DWN_TM (Pump Minimum Down Time)	minutes	The minimum time that a Pumped Storage Hydro Resource must stay out of pumping mode after switching out of that mode.	• Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP
MIN_DWN_TM_GP (Gen-to-Pump Minimum Down Time)	minutes	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.	
MIN_DWN_TM_PG (Pump-to-Gen Minimum Down Time)	minutes	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.	
MAX_PUMP_SD_CST (Pump Maximum Shutdown Cost)	$/shutdown	The maximum cost it would take to shut down the pump.	• Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP
PUMP_SHTDWN_TM (Pump Shutdown Time)	minutes	The pump shutdown time	• Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP
COST_RANK_LMPM (Variable Cost Option)	1, 2, 3	A method of calculating Default energy Bids based on fuel costs and variable operations and maintenance costs.	• Default setting is 1 • Only one of the three ranking fields (COST_RANK_LMPM, NEGO_RANK_LMPM, and PRC_RANK_LMPM) can be ranked as 1
NEGO_RANK_LMPM (Negotiated Rate Option)	1, 2, 3	A method of calculating Default energy Bids based on a negotiation with the CAISO or an Independent Entity.	• Default setting is 2 • Only one of the three ranking fields (COST_RANK_LMPM, NEGO_RANK_LMPM, and PRC_RANK_LMPM) can be ranked as 1

RDT Column Name	Unit	Definition	Business Rule
PRC_RANK_LMPM (LMP Option)	1, 2, 3	A method of calculating Default energy Bids based Locational Marginal Prices.	• Default setting is 3 • Only one of the three ranking fields (COST_RANK_LMPM, NEGO_RANK_LMPM, and PRC_RANK_LMPM) can be ranked as 1
RSRV_CAP_SPIN (Reserve Capacity: Spin)	MW	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.	• Must have a value if CERT_SPIN is Y. • Cannot be greater than the tested Spin capacity. • Must be <= (MAX_GEN - MIN_GEN)
RSRV_CAP_NSPIN (Reserve Capacity: Non-Spin)	MW	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.	• 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 <= MAX_GEN
CERT_REG_DOWN (Certified for AS: Regulation Down)	Y/N	An identifier of a resource that is certified to provide Regulation Down	• If Y, the REG and RREG curves must be defined
CERT_REG_UP (Certified for AS: Regulation Up)	Y/N	An identifier of a resource that is certified to provide Regulation Up	• If Y, the REG and RREG curves must be defined
CERT_SPIN (Certified for AS: Spin)	Y/N	An identifier of a resource that is certified to provide Spinning Reserve.	• If Y, RSRV_CAP_NSPIN must have a value and the ROPR curve must be defined
CERT_NSPIN_DAM (Certified for AS DAM: Non-Spin)	Y/N	An identifier of a resource that is certified to provide Non-Spinning Reserve in the DAM.	• If Y, RSRV_CAP_NSPIN must have a value and the ROPR curve must be defined
CERT_NSPIN_RTM (Certified for AS RTM: Non-Spin)	Y/N	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.	• If Y, RSRV_CAP_NSPIN must have a value and the ROPR curve must be defined
REM (Regulation Energy Management)	Y/N	Indicator of a non-generator resource that participates only in the regulation markets.	

RDT Column Name	Unit	Definition	Business Rule
MIN_CONT_ENERGY_LIMIT (Minimum Continuous Energy Limit)	MWh	Minimum stored energy for an LESR. If no real physical energy limit, leave blank.	
MAX_CONT_ENERGY_LIMIT (Maximum Continuous Energy Limit)	MWh	Maximum stored energy for an LESR. If no real physical energy limit, leave blank.	
CURT_ENERGY_LIMIT (Curtailment Energy Limit)	MWh	The energy limit for curtailing the consumption of energy for NGR. If no limit, leave blank. This is a placeholder for future functionality.	
ENERGY_EFFIC (Energy Efficiency)	numeric	The percentage of charging energy that the device can store and later discharge; 0<= n <=1	
EMISSION_RATE	mtCO2/ mmBTU	For gas-fired resources, the emission rate (mtCO2/mmBTU) used to determine a resource's greenhouse gas compliance obligation	
GHG_COMPLIANCE_OBLIG	Y / null	Indicator of a resource that has a green-house gas compliance obligation and is eligible to recover greenhouse gas allowance costs	
FORECAST_SELECTION	ISO or SC	Indicator for whether a resource will provide its own forecast (select 'SC') or will utilize the ISO's forecast (select 'ISO')	• VER flag must be Y for this election to be made • Selecting 'SC' requires certification

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.

RDT Column Name	Unit	Definition	
PGA_NAME (Participating Generator Agreement Name)		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	A revision to this name must match the name on the agreement.
SC_ID (Scheduling Coordinator ID)		An entity certified by the CAISO for the purposes of undertaking the functions specified in Section 4.5.3 of the CAISO Tariff.	
RES_ID (Resource ID)		The ISO resource identifier used for tracking each resource for market scheduling and outage coordination purposes.	
RES_NAME (Resource Name)		Descriptive Name for the Resource from the PGA or NSPGA Schedule 1, MSS Schedule 14, DR Registration, etc.	A revision to this name must match the facility name on the agreement schedule.
RES_TYPE (Resource Type)		Descriptive identifier denoting the type of resource: Generating Unit (GEN), Tie Generator (TG), Load.	
AGGREGATE_YN (Aggregate?)	Y/N	A generator resource that consists of more than one individual “child” resources as modeled in the CAISO system	
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	

RDT Column Name	Unit	Definition	
FUEL_TYPE (Primary Fuel Type)		Description of Primary Fuel Type of the Generator; such as, Natural Gas, Oil, Nuclear, etc. GAS – Natural Gas COAL – Coal/Coke DDR – Dispatchable Demand Response DIST - Distillate OIL – Oil NUCL – Nuclear WAST – Waste to Energy BIOM – Biomass GEOT – Geothermal LESR – Limited Energy Storage Resource SOLR – Solar WATR – Water BGAS – Bio Gas (Landfill Sewage Digester etc.) HRCV – Heat Recovery WIND – Wind OTHR – Other	A revision to fuel type must match the agreement schedule.
GEN_TECH_TYPE (Prime Mover Technology)		Description of the Prime Mover Technology associated with Generators ; such as, Hydro Turbine, Gas Turbine, Combined Cycle, etc HYDR – Hydro Turbine PTUR – Hydro Pump-Turbine GTUR – Gas Turbine STUR – Steam Turbine CCYC – Combined Cycle RECP – Reciprocating Engine PHOT – Photovoltaic WIND – Wind Turbine PUMP – Pump	A revision to technology type must match the agreement schedule.
GEN_TYPE (Generator Type)		H = Hydro resources T = Other resources	
FUEL_REGN_TYPE (Fuel Region)		Represents the fuel region price used in the calculation of Start-up and Minimum Load costs, as well as the variable based option for Default Energy Bid for a resource. For a full list of the available fuel regions, see here: [http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx] See Attachment C for how to request a change to fuel region.	

RDT Column Name	Unit	Definition	
ELECTRIC_REGN (Electric Region)		The electric region associates the corresponding electricity price for the resource's startup auxiliary power. For a full list of the available electric regions, see here: [http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx] Each fuel region has a corresponding wholesale electric region. See Attachment M for how to request a retail electric region.	
POWER_PRICE_HUB (Power Price Hub)		Power trading hub assignment to associate the wholesale power price appropriate to a resource or Multi-Stage Generator based on the power price hub location documented in Open Access Transmission Tariffs for the Balancing Authority Area where the resource is located or if unavailable then the closest trading hub to the resource location. PHMIDC - Mid-Columbia PHPALO - Palo Verde PHNP15 – North of Path 15 PHSP15 – South of Path 15	

RDT Column Name	Unit	Definition	
AQM_DIST_TYPE (Air Quality Management District)		The Air Quality Management District or Air Pollution Control District in which the resource is located. AMAD – Amador ANTV - Antelope Valley BUTT – Butte CALA – Calaveras COLU – Colusa ELDO - El Dorado FRVR - Feather River GBUN - Great Basin Unified GLEN – Glenn IMPE – Imperial KERN – Kern LAKE – Lake LASS – Lassen MARI – Mariposa MBUN - Monterey Bay Unified MEND – Mendocino MODO – Modoc MOJD - Mojave Desert NCUN - North Coast Unified NSER - Northern Sierra NSON - Northern Sonoma OTHR - Other Region PLAC – Placer SACM - Sacramento Metro SBRB - Santa Barbara SCOA - South Coast SDIE - San Diego SFBA - San Francisco Bay Area SHAS – Shasta SISK – Siskiyou SJVU - San Joaquin Valley Unified SLUO - San Luis Obispo TEHA – Tehama TUOL – Tuolumne VENT – Ventura YOSO - Yolo/Solano	
CERT_PIRP (Certified PIRP)	Q, Y, P, I, N, or null	Q = Wind or solar resource in the process of having forecast information evaluated 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	

RDT Column Name	Unit	Definition	
MOO_QUALIFIED (Must Offer Obligation Qualified)	R or N,	N: Resource is exempt from CAISO inserting a Generated Bid R: CAISO will insert generated bids if a resource has a must offer requirement and is not exempt from bid generation and has not submitted a bid. .	
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.	
COM_MW (Commercial Operation for Market MW)	MW	The portion of a new Generating Unit that has synchronized to the CAISO controlled grid and has completed on-site test operations and commissioning that is allowed to Bid into the CAISO markets in advance of achieving COD for the entire Electric Generating Unit. NOTE, once the resource declares COD, this field will become null.	
COG (Constrained Output Generator Flag)	Y/N	The output of the generation resources is not variable, ie PMax = PMin. Y: output is constrained.	
CERT_BLKSTRT (Certified for Black Start)	Y/N	An identifer 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 identifer of a resource eligible to participate in the Day Ahead market.	• Y for Generators and TG resources • N for Discrete Dispatch RDRR and EIM resources (participating and non-participating)
CERT_RTM (Certified for Real Time Market)	Y/N	An identifer 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

RDT Column Name	Unit	Definition	
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)
LMPM (Market Power Mitigation Participation Flag)	Y/N	An identifier of a resource that is subject to the market power mitigation process. Defined per tariff.	• Y for Generators, TG resources, and participating EIM resources • N for non-participating EIM resources
MSS_LD_FLNG_DWN (MSS Load Following Down)	Y/N	Identifier if a resource is load following down – applies to Metered Subsystem only	
MSS_LD_FLNG_UP (MSS Load Following Up)	Y/N	Identifier if a resource is load following up – applies to Metered Subsystem only	
QF (FERC Qualifying Facility Flag)	Y/N	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	
USE_LIMIT (Use Limit)	Y/N	Identifier of a resource that is energy use limited, such as limitation of energy or emission control, etc.	
OPER_MAINT_COST (Operating Maintenance Cost Adder)	$/MWh	Variable operations and maintenance (O&M) costs. See Exhibit 4-2 in Section 4 in the body of this BPM for default values of O&M cost adders. For resources that have a negotiated O&M adder, that value will display in this field.	Contact ndeb@caiso.com to establish a negotiated O&M adder.
OPER_MAINT_ADDER_TYPE (Operating Maintenance Cost Adder Type)	D/N	This flag identifies whether the Operating Maintenance Cost Adder is the default value (D) or a negotiated (N) value.	
PRIOR_TYPE (Priority Type)		Designator of Regulatory Must-Run, Reliability Must Run, and Must Take resources	
DISP (Dispatchable)	Y/N	Designates a dispatchable resource	
DISCRETE_DISP (Discrete Dispatch)	Y/null	Indicator of a resource that is dispatchable for a specified megawatt quantity. Applies to Reliability Demand Response only.	
RMR (Reliability Must Run)		Designates a resource that has a Reliability Must Run contract	

RDT Column Name	Unit	Definition	
MAX_RR (Maximum Ramp Rate)		This is a derived field that represents the maximum ramp rate in the operational ramp rate curve.	
PRC_SET_DAM (Price Setter – DAM)		Can set Market Clearing price in Day Ahead market	
PRC_SET_RTM (Price Setter – RTM)		Can set Market Clearing price in Real Time market	
MSG_YN (Multi-Stage Generator Flag)	Y/null	Indicator of a resource that is modeled with multiple configurations under the Multi-Stage Generator (MSG) model.	
STARTUP_RAMP_TIME (Startup Ramp Time)		Represents the time it takes to physically ramp unit from zero to pmin after the closing of the breaker.	
SUPPLY_CONFIG_YN (Supplied Configuration Flag)		This is a placeholder for future functionality.	
HR_PRE_DISP (Hourly Pre-Dispatch)	Y/N/null	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)	
NGR (Non Generator Resource Flag)	Y/N/null	Indicator of a non-generator resource Y = NGR N or null = not NGR	
CHP (Combined Heat and Power Resource Flag)	Y/N/null	Indicator of a combined heat and power resource Y = CHP N or null = not CHP	
RMTG_MAX_ON_PEAK (RMT Max On Peak)	MW	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.
RMTG_ON_PEAK_EXPIR_DT (RMT Max On Peak)	DD/MM/YY	Expiration date of the stated RMTG-eligible capacity For exempt QF resources, no expiration date applies.	

RMTG_MAX_OFF_PEAK (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.	
ADDER_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 MMAs@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.

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Segment Type = RAMP			
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 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
Market Ramp Rate (RAMP_MKT_RAMP_RATE)		*This data element is not currently used.*	

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

RDT Colun Name	Unit	Definition	Business Rule
Resource ID			
Segment Type = HEAT			
Segment Number		The point numbers 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 11 points allowed
Heat Rate Operating Level	MW	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.	• Value of the first point must equal MIN_GEN • Value of the last point must equal MAX_GEN • A break-point cannot fall within a Forbidden region • A break-point cannot fall within a Regulation range
Heat Rate HEAT_HEAT_RATE	BTU / kWh	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.	Heat Rate must be provided if FUEL_TYPE = GAS 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)]
Emission Rate HEAT_EMISSION_RATE	lbs of NOx/MWh	*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)	
Average Cost	$/MWh	Use this value for fuel costs of non-gas fired units instead of Heat Rate and natural gas	These values are used to calculate the incremental fuel

RDT Colun Name	Unit	Definition	Business Rule
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.

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Segment Type = STRT			
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 down time 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)

RDT Column Name	Unit	Definition	Business Rule
Start-Up Time	minutes	Startup 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 MMAs@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.

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Segment Type = FBRD			
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 >= 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 <= 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 >= 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.

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Segment Type = REG			
Segment Number		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.	• Up to 2 segments allowed.
Lower MW for Regulation	MW	The Lower MW output of the current Regulation Range segment.	• Must be >= MIN_GEN
Higher MW for Regulation	MW	The Higher MW output of the current Regulation Range segment.	• Must be > Lower MW for Regulation and <= MAX_GEN

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.

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Segment Type = RREG			
Segment Number		One regulation ramp rate is allowed per resource and applies to all defined regulation ranges for the resource.	• 1 segment allowed
Worst Regulation Ramp Rate	MW/ minute	The maximum Regulation Ramp Rate under the worst condition.	• Must be > 0
Best Regulation Ramp Rate	MW/ minute	The maximum Regulation Ramp Rate under the best condition.	• Must be <= Best Operating Ramp Rate (RAMP curve) • Must be <= the tested Regulation ramp rate
Market Regulation Ramp Rate		*This data element is not currently used.*	

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.

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Segment Type = ROPR			
Segment Number		One operating reserve ramp rate covers procurement of both Spinning and Non-Spinning reserve.	• 1 segment allowed
Worst Operating Res Ramp Rate	MW/ minute	The maximum Operating Reserve Ramp Rate under the worst condition	• Must be > 0
Best Operating Res Ramp Rate	MW/ minute	The maximum Operating Reserve Ramp Rate under the best condition.	• Must be <= Best Operating Ramp Rate (RAMP curve) • Must be <= the tested Spin or Non-Spin ramp rate
Market Operating Res Ramp Rate		*This data element is not currently used.*	

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

RDT Column Name	Unit	Definition	Business Rule
Resource ID		The ISO resource identifier used for tracking each resource for market scheduling and outage coordination purposes.	
Configuration ID		Identifier of the MSG configuration.	
Configuration Name		MSG configuration name	

RDT Column Name	Unit	Definition	Business Rule
Maximum Generation Capacity	MW	The maximum normal capability at the configuration level.	• Config's MAX_GEN <= resource's MAX_GEN • Config's MAX_GEN >= config's MIN_GEN • Must equal the maximum output level (last segment) in the config's HEAT curve • Must equal the maximum output level (last segment) in the config's RAMP curve
Minimum Generation Capacity	MW	For a configuration, the minimum sustained operating level (Pmin) at which it can operate at a continuous level.	• Config's MIN_GEN >= resource's MIN_GEN • Config's MIN_GEN <= config's MAX_GEN • Must equal the minimum output level (segment 1) in the config's HEAT curve • Must equal the minimum output level (segment 1) in the config's RAMP curve
Minimum On Time	minutes	The minimum amount of time that the MSG resource will operate in this configuration	
Minimum Off Time	minutes	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.	• Cannot be null for a start-able configuration
Minimum Load Cost	$ / hour	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.	• Cannot be null if ML Cost Basis Type of REGC (Registered) is selected
Reserve Capacity: Spin	MW	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.	• Must have a value if CERT_SPIN is Y. • Cannot be greater than the tested Spin capacity. • Must be less than or equal to MAX_GEN - MIN_GEN of the configuration

RDT Column Name	Unit	Definition	Business Rule
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 shutdown 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 Down	Y / N	An indentifier of a configuration that is certified to provide Regulation Down Reserve.	• Set to Y if configuration is certified for Regulation Down • Must be Y for at least one configuration if resource is certified for regulation down
Certified for AS: Regulation Up	Y / N	An indentifier 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 indentifier 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

RDT Column Name	Unit	Definition	Business Rule
Certified for AS DAM: Non-Spin	Y / N	An indentifier of a configuration that is certified to provide Non-Spinning Reserve in the DAM.	• Set to Y if configuration is certified for Non-Spin • Must be Y for at least one configuration if resource is certified for non-spin
Certified for AS RTM: Non-Spin	Y / N	An indentifier of a configuration 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.	• Set to Y if configuration is certified for Non-Spin • Must be Y for at least one configuration if resource is certified for non-spin
Minimum Load Major Maintenance Adder	$/hour	A configuration-specific adder for minimum load cost, if applicable. This field is READ-ONLY.	Contact MMAs@caiso.com to establish this value or revise it.
RA Range Min	MW	For each configuration, indicates the minimum level of Resource Adequacy capacity that the configuration will provide.	• 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 • RA Range Min of subsequent configurations must be equal to the RA Range Max of the previous configuration plus 0.01. • 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
RA Range Max	MW	For each configuration, indicates the maximum level of Resource Adequacy capacity that the configuration will provide.	• Must be equal to or less than the MAX_GEN for that configuration

RDT Column Name	Unit	Definition	Business Rule
Implied Starts		Indicates the n number of starts associated with moving a MSG resource from offline to online or from a lower configuration to a higher configuration that is defined by the use limitation plan's supporting documentation. Each implied start will contribute to the usage of the start limitation on file in the ULPDT in the 'LIMITATION' field. Implied starts registered in the GRDT should be the same resolution level on which the start limitation value is determined. Only use limited MSG resources with start limitation(s) can have implied starts greater than 1. MSG resources with registered start limitations have to include an implied start value in the MSG_CONFIG tab of the GRDT for every configuration of the MSG resource. For each configuration, the number of implied starts for an MSG configuration shall be measured from the MSG resource being entirely off to being started directly to that configuration. An implied start for the configuration can be set to zero. .	• Required if USE_LIMIT = Y for the MSG resource and must be 1 or greater.

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.

RDT Column Name	Unit	Definition	Business Rule
Configuration ID - From		This configuration ID is the starting point for a transition between two configurations. Each transition represents one direction.	
Configuration ID - To		This configuration ID is the ending point for a transition between two configurations. Each transition represents one direction.	
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	
Market Max Daily Transitions		*This data element is not currently used.*	
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	

RDT Column Name	Unit	Definition	Business Rule
Implied Starts		This is a derived value equal to the IMPLIED_STRTS of the "TO Configuration" minus the IMPLIED_STRTS of the "FROM Configuration". This field is READ-ONLY	

B.2.12 MSG Configuration Ramp Rate Curve – CONFIG_RAMP tab

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Configuration ID			
Segment Type = RAMP			
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 (RAMP_MAX_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
Market Ramp Rate (RAMP_MKT_RAMP_RATE)		*This data element is not currently used.*	

B.2.13 MSG Configuration Heat Rate Curve – CONFIG_HEAT tab

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Configuration ID			
Segment Type = HEAT			
Segment Number		The point numbers between the PMin and PMax of the configuration MW output. The point starts at 1. Up to 11 points are allowed.	• First point must be 1 • Point numbering must be sequential • No more than 11 points allowed
Heat Rate Operating Level	MW	The configuration MW output at point 1. The first point (1) of MW output must start at the configuration's PMIN. The last point (n) 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
Heat Rate	BTU/kWh	For gas-fired units only, the average heat rate of the configuration 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 poin (n) (PMax). If not a gas-fired unit, leave blank and instead complete the Average Heat Cost field.	Heat Rate must be provided if resource's Fuel Type = Gas
Heat Emission Rate	lbs of NOx/MWh	*This is informational only - Market software does not reference this data element.* The emission rate of the configuration 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).	
Average Cost	$/MWh	Use this value for non-gas fired units to represent fuel costs instead of Heat Rate and natural gas price index. The average cost of the configuration on point (i) in $. 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).	• Average Cost must be provided if resource's Fuel Type is not Gas. • 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

RDT Column Name	Unit	Definition	Business Rule
			charges. Average fuel cost values may be subject to verification and require supporting documentation upon request by the ISO.

B.2.14 MSG Configuration Start-Up Curve – CONFIG_STRT tab

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Configuration ID			
Segment Type = STRT			
Segment Number		The segment numbers corresponding to cooling time of the configuration. The segment starts at 1. Up to 3 segments are allowed (hot, warm and cold).	• First segment must be 1 • Segment numbers must be sequential • 3 segments allowed
Registered Cooling Time	minutes	The amount of time the configuration must be off (in minutes) within sequence (i). The first down time must be zero to account for a configuration has just shut down.	• Value in first segment must be 0
Startup Time	minutes	Startup Time is the time (in minutes) it takes a configuration to achieve PMin 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.	• Value must increase with each sequential segment
Startup Cost	$ / start	The startup cost of a configuration (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. Startup cost provided for a start-able GAS configuration under Proxy Cost, or for any "indirect" configuration, will be ignored by the software.	• Value must increase with each sequential segment • May not exceed 150% of configuration'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

RDT Column Name	Unit	Definition	Business Rule
Start-Up Aux	MWh	The electrical power used by a configuration during startup, or for an "indirect" 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 "indirect" configuration will be used in the calculation for Transition Cost.	
Start-Up Fuel	mmBTU	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 "indirect" 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.	
Start-Up MMA	$ / start	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	Contact MMAs@caiso.com to establish this value or revise it.

B.2.15 MSG Configuration Regulation Range – CONFIG_REG tab

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Configuration ID			
Segment Type = REG			
Segment Number		Number of the regulation range. One regulation range is allowed for a configuration.	• 1 Segment allowed
Lower MW for Regulation	MW	Lower level of the Regulation Range.	• Must be >= MIN_GEN of configuration
Higher MW for Regulation	MW	Higher level of the Regulation Range.	• Must be <= MAX_GEN of configuration

B.2.16 MSG Configuration Regulation Ramp Rate – CONFIG_RREG tab

RDT Column Name	Unit	Definition	Business Rule
Resource ID			

RDT Column Name	Unit	Definition	Business Rule
Configuration ID			
Segment Type = RREG			
Segment Number		One regulation ramp rate is allowed for a configuration.	• 1 Segment allowed
Worst Regulation Ramp Rate	MW / minute	The maximum Regulation Ramp Rate for the segment under the worst condition.	• Must be > 0
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
Market Regulation Ramp Rate		*This data element is not currently used.*	

B.2.17 MSG Configuration Operating Reserve Ramp Rate – CONFIG_ROPR tab

RDT Column Name	Unit	Definition	Business Rule
Resource ID			
Configuration ID			
Segment Type = ROPR			
Segment Number		One ramp rate covers procurement of both Spinning and Non-Spinning reserve.	• 1 Segment allowed
Worst Operating Res Ramp Rate	MW / minute	The maximum Operating Reserve Ramp Rate under the worst condition	• Must be > 0
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)
Market Operating Res Ramp Rate		*This data element is not currently used.*	

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.

RDT Column Name	Definition	Business Rule
Aggregate Resource ID	The ISO resource identifier used for tracking each resource for market scheduling and outage coordination purposes.	
Aggregate Resource Name	Descriptive name for the resource.	
Child Resource ID	The ISO resource identifier used for tracking each resource.	
Child Resource Name	Descriptive name for the resource.	
Maximum Child Generation Capacity	The maximum generating capability of the child unit.	

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.

RDT Column Name	Definition	Business Rule
MIN_HR_BLK_LIM (Minimum Hourly Block Limit (1-24 hours))	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.	Must be a whole number from 1 to 24.
GMC_RANK_LMPM (Price Taker Option)	A method of calculating Generated Bids based on a price taker value of zero plus an estimate of the Grid Management Charge.	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
NEGO_RANK_LMPM (Negotiated Rate Option)	A method of calculating Generated Bids based on a negotiation with the CAISO or the Independent Entity.	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
PRC_RANK_LMPM (LMP Option)	A method of calculating Generated Bids based on Locational Marginal Prices.	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
HR_PRE_DISP (Hourly Pre_Dispatch)	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	

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	NEGO_RANK_LMPM	PRC_RANK_LMPM	GMC_RANK_LMPM
1			
2			**1**
3	**1**		
4		**1**	**2**
5	**2**	**1**	

- 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.

RDT Column Name	Definition	Business Rule
RES_ID (Resource ID)	The ISO resource identifier used for tracking each resource for market scheduling.	Once created, the resource ID cannot be changed. The resource must end-dated and a new resource ID created.
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

RDT Column Name	Definition	Business Rule
CERT_RUC (Certified for RUC)	Identifier of a resource that is eligible to participate in RUC.	This flag is set to Y if a resource has Resource Adequacy capacity for a given trade date.
MOO (MOO Resource)	This field is no longer used and will be removed in next version of IRDT	
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.

B.6 Use Limit Plan Data Template

The ULPDT is an Excel spreadsheet containing multiple worksheet tabs, which contain static use limitations stored in the CAISO Master File database. The worksheet tabs listed in the table below are described in the following sections:

Spreadsheet Tab	Contents
Instruction	Contains report details
Definition-GRDT	Link to blank template on CAISO website
Code	Blank
Use_Limit_Plan	Use limitation data

B.6.1 Use_Limit_Plan tab

Many of the data elements in the Use_Limit_Plan tab are modifiable via the ULPDT update process, by submitting a revised ULPDT through the Master File User Interface. Those data elements are described in the following table in the order they appear in the ULPDT[19].

RDT Column Name	Unit	Definition	Business Rule
SC_ID	Text	Scheduling Coordinator ID submitting the Use Limit Plan Data Template record.	• Cannot be null • Submitting SC must own the resource on the start date of the plan. • SC ID not valid for authenticated user.
RES_ID (Resource ID)	Text	Existing, active resource provisioned to the SC ID uploading the ULPDT	• Cannot be null • Resource must exist and be active in RDT

[19] For more information see Master File Interface User Guide version 1.8, http://www.caiso.com/Documents/MasterFileUserGuide_Mar2018.pdf.

RDT Column Name	Unit	Definition	Business Rule
CONFIG_ID (Configuration ID)	Text	Configuration ID associated to MSG Resource for MSG that have configuration level limitations. If the MSG is registering a parent resource level limitation, the CONFIG_ID field should be null.	• Configuration must exist and be active in RDT by effective start date
USE_LIMIT_TYPE (Use Limit Type)	Text	The type of resource operation that is impacted by the design, environmental, or qualifying contractual limitation. If the limitation restricts the energy output level of the resource, field value should be 'ENERGY'. If the limitation restricts the number of run-hours of the resource, field value should be 'RUNHOURS'. If the limitation restricts the number of starts of the resource, field value should be 'STARTS'. If the limitation restricts resource operation other than a start, run-hour, or energy output level, the field value should be 'OTHER'.	• Cannot be null • Value must be valid value of 'ENERGY', 'RUNHOURS', 'STARTS', or 'OTHER'
GRANULARITY (Granularity/Applicability)	Text	The granularity of the time period that the limitation is applicable to the resource operation. If the limitation restricts number of uses across a fixed, consecutive 12 month period, the field value should be 'ANNUALLY'. If the limitation restricts number of uses across a rolling, consecutive 12 month period, the field value should be 'ROLL_12'. If the limitation restricts number of uses across a month period, the field value should be 'MONTHLY'. If the limitation restricts number of uses across a 24 hour period, the field value should be 'DAILY'. If the limitation restricts number of uses across a period other than those available, the field value should be 'OTHER'.	• Cannot be null • Value must be valid value of 'ANNUALLY', 'ROLL_12, 'MONTHLY', 'DAILY', or 'OTHER'

RDT Column Name	Unit	Definition	Business Rule
PLAN_STRT_DT_TM (Effective Start Date)	Date	If the limitation number is a fixed limitation value across the registered granularity, this effective start date is the date the registered limitation becomes effective (MM/DD/YYYY). If the limitation number is a dynamic value that fluctuates across the registered granularity, this effective start date is the date the relevant granularity period becomes effective (MM/DD/YYYY).	• Cannot be null • Cannot overlap with incomplete or complete existing record with same Resource ID, Limit Type, Granularity, and Configuration • Must fall within start and end date of resource and configuration, if applicable • Must align with first day of month unless granularity is 'DAILY'
PLAN_END_DT_TM (Effective End Date)	Date	If the limitation number is a fixed value across the registered granularity, this effective end date is the date the registered limitation expires (MM/DD/YYYY). If the limitation number is a dynamic value that fluctuates across the registered granularity, this effective start date is the end date the relevant granularity period ends (MM/DD/YYYY).	• Cannot be null • Cannot overlap with incomplete or complete existing record with same Resource ID, Limit Type, Granularity, and Configuration • Must fall within start and end date of resource and configuration, if applicable • Must align with last day of month unless granularity is 'DAILY' • Must span multiple of 12 consecutive months if granularity is 'ANNUALLY' • Must span 12 or more consecutive months if granularity is 'ROLL_12' • Must occur after PLAN_STRT_DT_TM

RDT Column Name	Unit	Definition	Business Rule
LIMITATION (Limitation Number)	Numeric	The number or amount of the uses for the use limit type that is availble for use for each granularity period (e.g. number of starts for the year). For a use limitation registered as a fixed value limitation, the same number of uses will be made available at the beginning of each granularity until the limitation type expires. For a use limitation registered as a dynamic value limitation or for use limitations registered with 'OTHER' granularities, the number of uses made available at the beginning of each granularity will vary and the limitation number is associated with granularity period start and end date (PLAN_STRT_DT_TM and PLAN_END_DT_TM).	• Cannot be null • Cannot be negative • Cannot be 0 • Cannot be a fraction if use limit type is 'START'
MIN_USE_LIMIT (Minimum Capacity Level Subject to Use Limitation)	MW	*This data element is not used*	
MAX_USE_LIMIT (Maximum Capacity Level Subject to Use Limitation)	MW	*This data element is not used.*	
DOC_NAME (Supporting Documentation Details)	Text	Each record must have a CAISO determination that the use limitatino is a valid limitation to be submitted for registration in Master File User Interface. CAISO will attach to each CIDI ticket requesting registration a document identifying each limitation record accepted for registration. This field must contain in the following order: CIDI Ticket #, documentation name, page number, if LIMITATION is a fixed or dynamic limitation. Use the exact string, 'CIDI Ticket #'.	• Cannot be null • Cannot exceed 255 characters

B.6.2 Daily limitations

The day-ahead market time horizon of 24 hours allows the optimization to recognize daily limitations for resources that participate in the day-ahead market. Resources with binding commitment instructions in the day-ahead time frame will not be eligible to register daily use limitations for use limit types of START. The Scheduling Coordinator should utilize the Master File operating characteristic fields to the extent possible for:

- Maximum Daily Transitions

- Maximum Startups per Day
- Pump Maximum Daily Startups
- Maximum Daily On Time
- Maximum On Time (Not Used in Market)

The SC should also reflect its daily ENERGY use limit type by submitting the maximum daily energy limit bid through SIBR.

The following example is how the SC should create the record for daily limitations.

Resource with Daily Limitation with fixed limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	RES_D		RUNHOURS	DAILY	1/1/2018	12/31/2018	6			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_D		RUNHOURS	DAILY	1/1/2019	12/31/2019	6			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: Daily limitation (fixed or dynamic)

Regardless of whether the limitation is fixed or dynamic in nature, the SC should create daily records with effective ranges of 12 month increments. The value in the ULPDT should be a projected value if the limitation is of a dynamic nature.

REMINDER: Daily limitations are not eligible for Opportunity Cost adders. SC should ensure it registers its operating characteristics in the GRDT and/or bids daily energy limit. If the resource has a validated daily use limitation, the SC will be exempt from bid generation and have access to short-term use limit reached card to ration uses within the operating day.

B.6.3 Monthly limitation

Monthly limitations may only be registered for the current or upcoming calendar year and should specify use limit type, granularity, effective period for the plan, and fixed or dynamic limitation number. Include the fixed or dynamic information in DOC NAME field. The examples below in Section B.6.2.1 show resources with monthly limitations of a fixed or dynamic nature.

The fixed examples below show resources with monthly use limitations where the plan documents specify the number of the limitation explicitly in the plan. The limitation values will be fixed for the term of the limitation (fixed values), where changes to the limitation value are not supported. If a resource has a revision to its use limitation that changes the explicit limitation number then the SC must submit a new Use-Limited Resource registration request. Monthly limitations may only be registered for the current or upcoming calendar year.

The dynamic examples below show resources with monthly use limitations where the plan documents support that the specific limitation value will vary throughout the term of the plan.

The limitation value will be dynamic for the term of the limitation (dynamic values), where changes to the limitation value are eligible ULPDT updates. If the resource has a revision to its use limitation that changes the drivers that the limitation number is a function of then the SC must submit a new Use-Limited Resource registration request. Otherwise changes in limitation values as supported by the use plan should be reflected through updates to the Use Limit Plan Data Template with the CIDI # included for the approved limitation. Updated values are updated projections on the uses available across the granularity period – a year – based on more accurate, up-to-date information. The value remains the limitation across the period, the CAISO processing will account for prior uses. A justification for updates to the ULPDT is needed to explain the change in values.

B.6.3.1Resource Examples

Initial submission for RES_B that is defined as a fixed value in documentation. The SC should submit a single record the year and flag the granularity as 'MONTHLY.' The limitation number will be applied on the same level as the granularity flag. For example, the following table shows RES_B with a monthly limitation on its starts where each month from 1/1/2018 through 12/31/2018 is limited to 50 starts per month.

Resource with Monthly Limitation with fixed limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	RES_B		START	MONTHLY	1/1/2018	12/31/2018	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_B		START	MONTHLY	1/1/2019	12/31/2019	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: Monthly fixed limitation

Initial submission for RES_B where the limitation is defined as dynamic (e.g. fluctuations of storage capability). If the SC projects its usage capabilities on a monthly basis based on end-of-month storage inventory targets, these limitations would apply on a granularity level and would likely need to reflect various values for each month. In this case, the SC has the ability to submit the ULPDT records in monthly profiles with the initial projects. The monthly profiles span 2018 and 2019 and reflect prior months ULPDT records effective today and future months' projections, if available. If unavailable, attach a ULPDT with blank records for those months.

Resource with Monthly Limitation with dynamic limitation (e.g. changes in storage capability)										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	RES_B		START	MONTHLY	1/1/2018	1/31/2018	50			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	2/1/2018	2/28/2018	40			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	3/1/2018	3/31/2018	30			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	4/1/2018	4/30/2018	20			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	5/1/2018	5/31/2018	20			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	6/1/2018	6/30/2018	30			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	7/1/2018	7/31/2018	30			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	8/1/2018	8/31/2018	20			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	9/1/2018	9/30/2018	20			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	10/1/2018	10/31/2018	30			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	11/1/2018	11/30/2018	40			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.
SC_A	RES_B		START	MONTHLY	12/1/2018	12/31/2018	40			CIDI Ticket #00333333 Limited storage capability documented in Energy Revenue Recovery Acccount Filing, Page 4, dynamic value registered.

Example: Monthly dynamic limitation

B.6.3.2 Multi-Stage Generators

Initial submission for MSG_A with a plant level limitation that is defined as a fixed value limiting its use per month.

MSG with Monthly Limitation on the plant with fixed limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	MSG_A		START	MONTHLY	1/1/2018	12/31/2018	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	MSG_A		START	MONTHLY	1/1/2019	12/31/2019	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: MSG plant monthly fixed limitation

Initial submission for MSG_A with a configuration level limitation on its 3rd configuration that is defined as a fixed value limiting its use per month.

MSG with Monthly Limitation on the 3rd configuration with fixed limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	RES_A	CONFIG_3	START	MONTHLY	1/1/2018	12/31/2018	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_A	CONFIG_3	START	MONTHLY	1/1/2019	12/31/2019	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: MSG configuration monthly fixed limitation

MSG_C has both a plant level monthly limitation and a configuration level monthly limitation on its third configuration. Note – Example not intended to imply plant and configuration level combinations on a MSG should be on same granularity.

MSG with Monthly Limitation on the plant and 3rd configuration with fixed limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	RES_A		START	MONTHLY	1/1/2018	12/31/2018	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_A	CONFIG_3	START	MONTHLY	1/1/2018	12/31/2018	10			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_A		START	MONTHLY	1/1/2019	12/31/2020	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_A	CONFIG_3	START	MONTHLY	1/1/2019	12/31/2020	10			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: MSG plant and configuration monthly fixed limitations

B.6.4 Annual limitation

Annual limitations may only be registered for the current or upcoming calendar year and should specify use limit type, granularity, effective period for the plan, fixed or dynamic limitation, and limitation number. Include the fixed or dynamic information in DOC NAME field. The examples below in Section B.6.4.1 show resources and Multi-Stage Generators with annual limitations of a fixed or dynamic nature.

The example below shows resource with annual use limitations where the plan documents specify the numbers of the limitation explicitly in the plan. The limitation values will be fixed for the term of the limitation (fixed values), where changes to the limitation value are not supported. If the resource has a revision to its use limitation that changes the explicit limitation number then the SC must submit a new Use-Limited Resource registration request.

The examples below show resources with annual use limitation where the plan documents support that the specific limitation values will vary throughout the term of the plan. The limitation values will be dynamic for the term of the limitation (dynamic values), where changes to the limitation values are eligible ULPDT updates. If the resource has a revision to its use limitation that changes the drivers that the limitation number is a function of, then the SC must submit a new Use-Limited Resource registration request. Otherwise changes in limitation values as supported by the use plan should be reflected through updates to the Use Limit Plan Data Template with the CIDI # included for the approved limitation. Updated values are updated projections on the uses available across the granularity period – a year – based on more accurate, up-to-date information. The value remains the limitation across the

period, the ISO processing will account for prior uses. A justification for updates to the ULPDT is needed to explain the change in values.

B.6.4.1 Resource Examples

Initial submission for RES_A that is defined as a fixed value in documentation where the 12 month increment begins in January as stated in the use plan.

Resource with annual limitation that begins in January every year with fixed limitation values										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	RES_A		START	ANNUALLY	1/1/2018	12/31/2018	300			CIDI Ticket #0002890 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_A		START	ANNUALLY	1/1/2019	12/31/2019	300			CIDI Ticket #0002890 Air quality management district permit, page 10, fixed value registered.

Example: Annual fixed limitation beginning in January

Initial submission for RES_B that is defined as a fixed value in documentation where the 12 month increment begins in March as stated in the use plan. ISO understands annual plans (plans that span 12 months before the use is available) can begin the first day of any month in the calendar year. ISO does not anticipate any will begin on a day different than the first day of a month.

Resource with Annual Limitation that begins in March every year with fixed limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	RES_B		START	ANNUALLY	3/1/2017	2/28/2018	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_B		START	ANNUALLY	3/1/2018	2/28/2019	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_B		START	ANNUALLY	3/1/2019	2/28/2020	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: Annual fixed limitation beginning in March

Initial submission for RES_C that is defined as a dynamic value in documentation, most likely as a result of a limitation for limited storage capability (gas or hydro). CAISO anticipates resource is likely to update values during the effective period of the limitation. Updates should note reason for update.

Resource with Annual Limitation that begins in January every year with dynamic limitation (e.g. changes in storage capability)										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation	Minimum Capacity	Maximum Capacity	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	RES_C		ENERGY	ANNUALLY	1/1/2018	12/31/2018	200000			CIDI Ticket #00444444 Limited storage capability and reliability requirement for load documented in PUC Order, Page 4, dynamic value registered.
SC_A	RES_C		ENERGY	ANNUALLY	1/1/2019	12/31/2019	200000			CIDI Ticket #00444444 Limited storage capability and reliability requirement for load documented in PUC Order, Page 4, dynamic value registered.

Example: Annual dynamic limitation beginning in January

Update submission during the year for limitations registered as having values that can vary throughout period: SCID ABCD, submits an updated ULPDT for RES_C on 11/1/2018 for the

effective period previously registered. This is backdating the effective limitation. Note: Now that the SC has an annual projection for 2019, the ULPDT record for 2019 should be submitted through the Master File UI.

Resource with Annual Limitation that begins in January every year with dynamic limitation (e.g. changes in storage capability)										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	RES_C		ENERGY	ANNUALLY	1/1/2018	12/31/2018	150000			CIDI Ticket #00444444 Limited storage capability and reliability requirement for load documented in PUC Order, Page 4, dynamic value registered.
SC_A	RES_C		ENERGY	ANNUALLY	1/1/2019	12/31/2019	150000			CIDI Ticket #00444444 Limited storage capability and reliability requirement for load documented in PUC Order, Page 4, dynamic value registered.

Example: Update to annual dynamic limitation beginning in January

B.6.4.2 Multi-Stage Generator Examples

Initial submission for MSG_A with a plant level limitation that is defined as a fixed value in documentation where the 12-month increment begins in January as stated in the use plan.

MSG with Annual Limitation on the plant that begins in January every year with fixed limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	MSG_A		START	ANNUALLY	1/1/2018	12/31/2018	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	MSG_A		START	ANNUALLY	1/1/2019	12/31/2019	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: MSG plant annual fixed imitation beginning in January

Initial submission for MSG_B where the configuration level limitation on the 3rd configuration is defined as a fixed value in documentation where the 12-month increment begins in March as stated in the use plan. CAISO understands annual plans (plans that span 12 months before the use is available) can begin the first day of any month in the calendar year. CAISO does not anticipate any will begin on a day different than the first day of a month.

MSG with Annual Limitation on the configuration that begins in January every year with fixed limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	MSG_B	CONFIG_3	START	ANNUALLY	1/1/2018	12/31/2018	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	MSG_B	CONFIG_3	START	ANNUALLY	1/1/2019	12/31/2019	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: MSG configuration annual fixed limitation beginning in March

Initial submission for MSG_C that is defined as a fixed value in documentation where the 12-month increment begins in January as stated in the use plan. MSG_C has both a plant level annual limitation and a configuration level annual limitation on its third configuration. Note – Example not intended to imply plant and configuration level combinations on a MSG should be on same granularity.

MSG with Annual Limitation on the plant and configuration that begins in January every year with fixed limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	MSG_C		START	ANNUALLY	1/1/2018	12/31/2018	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	MSG_C	CONFIG_3	START	ANNUALLY	1/1/2018	12/31/2018	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	MSG_C		START	ANNUALLY	1/1/2019	12/31/2020	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	MSG_C	CONFIG_3	START	ANNUALLY	1/1/2019	12/31/2020	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: MSG plant and configuration annual fixed limitations

Initial submission for MSG_B with a configuration level limitation that is defined as a dynamic value in documentation. The limitation is on the multi-stage generator for a start into its 3rd configuration. See Section 4 for more details examples.

MSG with Annual Limitation on the configuration that begins in January every year with dynamic limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	MSG_B	CONFIG_3	START	ANNUALLY	1/1/2018	12/31/2018	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	MSG_B	CONFIG_3	START	ANNUALLY	1/1/2019	12/31/2019	50			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: MSG annual dynamic limitation beginning in January

Update submission during the year for limitations registered as having values that can vary throughout period: SCID ABCD, submits an updated ULPDT for MSG_B on 11/1/2018 for the effective period previously registered. This is backdating the effective limitation. Note: Now that the SC has an annual projection for 2019, the ULPDT record for 2019 should be submitted through the Master File UI.

MSG with Annual Limitation on the configuration that begins in January every year with dynamic limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	MSG_B	CONFIG_3	START	ANNUALLY	1/1/2018	12/31/2018	45			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	MSG_B	CONFIG_3	START	ANNUALLY	1/1/2019	12/31/2019	55			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: Update to MSG annual dynamic limitation beginning in January

B.6.5 Rolling 12 limitation

The Scheduling Coordinator should submit ULPDT tab with a rolling 12 limitation with effective dates that represent the effective period of the rolling 12 limitation. For example, if the supporting documentation states the limitation is effective for 4 years, the plan end date To support the CAISO ability to model opportunity cost for the rolling 12 limitations, the Scheduling Coordinator must have a ULPDT record with effective dates that span at least 11 months prior and 11 months after the effective month of the opportunity cost calculation. For example, if the opportunity costs are to be calculated for effective month of May 2019, the plan end date in the ULPDT should be at least through April 2020.

B.6.6 Other limitation

The CAISO understands that a resource may specify a limitation that is applied on a basis greater than one month but that does not fall into either ANNUALLY or ROLL_12 granularity.

The OTHER granularity can be used to submit ULPDT records that provide the granularity of the limitation using the effective start and effective end dates. The limitation value is associated with the entire effective period.

The limitations may only be registered for the current or upcoming calendar year and should specify use limit type, granularity, effective period for the plan, fixed or dynamic limitation, limitation number. Include the fixed or dynamic information in DOC NAME field. The examples below show resources and Multi-Stage Generators with monthly limitations of a fixed or dynamic nature.

The fixed example below shows resource with quarterly use limitation where the plan documents specify the number of the limitation explicitly in the plan. The limitation value will be fixed for the term of the limitation (fixed values), where changes to the limitation value are not supported. If a SC receives a revised use plan that changes the explicit limitation number then the SC must submit a new Use-Limited Resource Registration request. Monthly limitations may only be registered for the current or upcoming calendar year.

If the nature of the limitation is dynamic, the limitation would be registered similarly to the other examples of dynamic limitations. The initial submission is based on a projection and updated as up-to-date information is available. The effective period does not change with updates only the limitation number.

Resource with Quarterly Limitation with fixed limitation										
SC ID	Resource ID	Configuration ID	Use Limit Type	Granularity	Effective Start Date	Effective End Date	Limitation Number	Minimum Capacity Level	Maximum Capacity Level	Documentation Name
SC_ID	RES_ID	CONFIG_ID	USE_LIMIT_TYPE	GRANULARITY	PLAN_STRT_DT_TM	PLAN_END_DT_TM	LIMITATION	MIN_USE_LIMIT	MAX_USE_LIMIT	DOC_NAME
SC_A	RES_B		START	OTHER	1/1/2018	3/31/2018	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_B		START	OTHER	4/1/2018	6/30/2018	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_B		START	OTHER	7/1/2018	9/30/2018	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_B		START	OTHER	10/1/2018	12/31/2018	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_B		START	OTHER	1/1/2019	3/31/2019	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_B		START	OTHER	4/1/2019	6/30/2019	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_B		START	OTHER	7/1/2019	9/30/2019	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.
SC_A	RES_B		START	OTHER	10/1/2019	12/31/2019	300			CIDI Ticket #00204555 Air quality management district permit, page 10, fixed value registered.

Example: Other fixed limitation on quarterly granularity

Attachment C

GAS PRICE CALCULATION RULES

C Fuel Region Gas Price Calculation Rules

C.1 Background

The daily fuel region gas price 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 fuel region price has a number of key components:

- Gas Price Index ($/MMBtu)
- Marginal Transportation Rates ($/MMBtu)
- Cap-and-trade credits to the base natural gas transportation rate
- Fuel Reimbursement Rate adjustments to the base natural gas transportation rate
- Miscellaneous costs including taxes

The gas price calculated for resources assigned to a BAA regional fuel region (e.g., CISO) will be the minimum of all fuel region values within the BAA. Monthly futures gas prices are used in the calculation of Demand Response net benefits test (DR NBT) threshold prices, electricity price indices, and projected proxy costs. The monthly price is calculated similar to the daily price, but using an average of several days' futures prices instead price(s) for a single trading day.

The current list of fuel regions defined for CAISO and EIM entities is located here: [http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx]

C.2 Request a Gas Fuel Region

C.2.1 Establish a new Gas Fuel Region

A Scheduling Coordinator can submit a request to establish a new fuel region. The following items are required:

- Natural gas pricing location
- Transportation rates ($/therm) publication: Transportation rates found on the gas companies' electric generation schedules and/or pipeline company pricing tariff schedule. [Include links and location of the specific schedule.]

- Documentation that the base natural gas transportation rate includes cap-and-trade credits
- Documentation of any fuel reimbursement or shrinkage allowances
- Documentation of any additional miscellaneous costs including taxes. Include links and the specific schedule.

Requests for a new fuel region can be submitted via the CIDI system using the subject “Request for new fuel region”. The timeline for the establishment of a new fuel region will depend on the availability of the components submitted, i.e., whether the CAISO already subscribes to a publication that includes prices for the proposed location. The CAISO will contact the Scheduling Coordinator if additional information in needed to establish the fuel region.

C.2.2 Assign a resource to a Fuel Region

Scheduling Coordinators for resources can submit a request through the CIDI system to change the fuel region associated for the resource using the subject “Assign resource to fuel region”. The request must include an invoice for the actual natural gas procurement for the resource. The CAISO will validate the submittal and change the fuel region in the Master File for the resource if the invoice supports the region change. Resources that do not submit information to support a specific fuel region designation will be assigned the BAA regional fuel region and the daily price for a BAA regional fuel region is the minimum of all gas price values within the BAA.

The validation process will include:

- Commodity price is geographically appropriate to resources physical location
- Base gas transportation rates are supported by invoices
- Cap-and-trade credits are supported by covered entities list and/or invoices
- Fuel reimbursement rate are supported by invoices
- Miscellaneous costs are supported by invoices

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 prices (per fuel region) for use in the next day's day-ahead and real-time markets. For the real-time market calculation, the CAISO uses at least two prices from two or more of the following publications: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, and Platt's Gas Daily. The fuel region prices reflect the commodity gas price index. If a fuel region has three vendor sources for gas prices and one vendor gas price is not available by 22:00 for any reason, the CAISO will use the gas prices from the two vendors that are available for the fuel region price. If a fuel region has three vendor sources for gas prices and two vendor gas prices are not available by 22:00 for any reason, the CAISO will use the fuel region price calculated for the prior trade date for that fuel region. If a fuel region has two vendor sources for gas prices and one vendor gas price is not available by 22:00 for any reason, the CAISO will use the fuel region price calculated for the prior trade date for that fuel region.

For the day ahead market calculation, the volume weighted average hub prices from ICE are obtained between 8 AM – 9 AM Pacific Time and used for the next day's day ahead market. If the ICE gas price is not available between 8 AM – 9 AM Pacific Time for the day-ahead market calculation for any reason, the CAISO will use the fuel region price calculated as described above.

C.3.2 Fuel Region Price Formula

The fuel region gas price is calculated as follows:

Fuel region price = Commodity gas price index + Total transportation cost

The total gas transport costs are based on the cost of marginal gas transport on the respective pipeline(s) or local distribution system(s). These costs may consist of: a marginal usage charge, cap-and-trade credit, a fuel reimbursement rate adjustment for in-kind fuel loss reimbursement/shrinkage, the FERC Annual Charge Adjustments (ACA) where indicated in the pipeline tariffs, or a state natural gas tax or applicable use taxes.

The formula for total transportation cost is:

Total transportation cost = Marginal transport cost + Cap-and-trade credit + Fuel reimbursement cost + Tax-based miscellaneous cost + Non-tax based miscellaneous cost

Where:

Fuel reimbursement cost = Gas price index *(Fuel reimbursement rate/(1-Fuel reimbursement rate))

The formula for tax-based miscellaneous cost is:

Tax-based miscellaneous cost = (Commodity gas price index + Marginal transport cost + Cap-and-trade credit + Non-tax based miscellaneous cost + Fuel reimbursement cost) * Tax Rate

C.4 Monthly Gas Prices for DR Net Benefits Test

The gas price used in the calculation of the Demand Response Net Benefits Test (DR NBT) threshold price is the average of the closing gas prices for all active gas delivery points for the trading days that existed through the X^{th} day of the current calendar month, for delivery in the next calendar month. The value 'X' is configurable; for the example below the CAISO will use trading days through the ninth calendar day of the month. The CAISO will calculate a monthly gas price for all fuel regions in the CAISO and EIM balancing areas[20]. The CAISO calculates future gas price indices for use in the calculation of the DR NBT threshold using an average from the Intercontinental Exchange, Natural Gas Intelligence and SNL Energy/BTU's Daily Gas Wire, as available.

The current gas delivery points are listed in the following table:

Gas Delivery Points
El Paso Permian
El Paso San Juan
El Paso/South Mainline
Kern Delivered
Kings Gate
Malin
Northwest Sumas
Northwest Wyoming Pool
Opal
PG&E Citygate
SoCal Citygate
Stanfield
TW Blanco

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.

[20] For any new EIM entity, the gas delivery point of the new EIM will not be calculated in their activation month.

Example

The following example includes detailed steps for calculating the monthly future gas price for one example gas delivery point, PG&E CityGate. 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[21] 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 M** are the average of the values in **column H**. Taking the average of the futures prices for PG&E CityGate through the ninth; we get a value of $5.11.

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.

[21] A basis swap price for any gas delivery point is the price difference between Henry Hub and that gas delivery point.

A	B	E	F	H	L	M	O	P	C
Closing Date	Trade Month	Henry Hub Price	Basis Swap at PG&E CityGate	Gas Delivery Price at PG&E CityGate		Avg PG&E (month-to-date)			
3/1/2012	Apr-12	$4.18	$0.66	$4.84		4.84			
3/2/2012	Apr-12	$4.17	$0.44	$4.61		4.73			
3/5/2012	Apr-12	$4.55	$0.51	$5.06		4.84			
3/6/2012	Apr-12	$4.92	$0.49	$5.41		4.98			
3/7/2012	Apr-12	$4.66	$0.42	$5.08		5.00			
3/8/2012	Apr-12	$4.98	$0.47	$5.45		5.08			
3/9/2012	Apr-12	$4.69	$0.65	$5.34		5.11			
3/12/2012	Apr-12	$4.71	$0.64	$5.35		5.14			
3/13/2012	Apr-12	$4.66	$0.56	$5.22		5.15			
3/14/2012	Apr-12	$4.61	$0.58	$5.19		5.16			
3/15/2012	Apr-12	$4.52	$0.65	$5.17		5.16			
3/16/2012	Apr-12	$4.25	$0.50	$4.75		5.12			
3/19/2012	Apr-12	$4.89	$0.68	$5.57		5.16			
3/20/2012	Apr-12	$4.86	$0.45	$5.31		5.17			
3/21/2012	Apr-12	$4.89	$0.65	$5.54		5.19			
3/22/2012	Apr-12	$4.64	$0.52	$5.16		5.19			
3/23/2012	Apr-12	$4.76	$0.56	$5.32		5.20			
3/26/2012	Apr-12	$4.08	$0.65	$4.73		5.17			
3/27/2012	Apr-12	$4.15	$0.65	$4.80		5.15			
3/28/2012	Apr-12	$4.66	$0.63	$5.29		5.16			
3/29/2012	Apr-12	$4.26	$0.69	$4.95		5.15			
3/30/2012	Apr-12	$4.17	$0.67	$4.84		5.14			

The final step is to calculate the average of the two month-to-date prices for all of the identified gas delivery points to determine the gas price used in the calculation of the DR NBT threshold price.

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Attachment D

CALCULATION OF DEFAULT ENERGY BIDS

D. Calculation of Default Energy Bids

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

A SC may modify the ranking of the three options for calculating the DEB up to two times during any 365-day period. If a 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 under the Negotiated Rate Option.

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

D.1 Day-Ahead

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

D.2 Real-Time

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

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

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

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

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

There are three methodology options for calculating DEBs:

- LMP Option: A weighted average LMP based on the lowest quartile of validated and/or corrected LMPs set at the Generating Unit location during Trading Hours in the last 90 days when the Unit was dispatched. Generating Units must pass a competitiveness screen to qualify for this option in which 50% of their MWh dispatches over the prior 90-days must have been dispatched competitively.
- Negotiated Rate Option: An amount negotiated with the CAISO. Even if a Resource has ranked the Negotiated Rate Option as the first choice, the CAISO will not calculate a new or updated negotiated default energy bid until the SC has commenced the negotiated default energy bid process and has provided sufficient information.
- Variable Cost Option: This option is based on the variable cost of the unit and includes a 10% adder for non-RMR capacity and a Variable Energy Opportunity Cost, if applicable. Furthermore this option is supplemented by the Frequently Mitigated Unit

(FMR) adder whereby certain units that are often mitigated qualify for a contribution towards their going-forward fixed costs. If a Resource has ranked the Variable Cost Option as the first choice, the complete curve (i.e., including all segments) of the Variable Cost Option will be calculated and selected.

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

The details of the three alternatives are described below.

D.4 LMP Option

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

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

- The first MW point is the Minimum Load
- The last MW point is the Maximum Capacity
- Each forbidden region is represented by a separate bid segment.
- The LMP-Based calculation will be used to modify the bid price for each segment that passes the Feasibility Test, which tests the availability of data for calculating the weighted average of the LMPs for the bid in each segment.
- Not eligible to include a Variable Energy Opportunity Cost in its calculation.

In the event that a resource fails the Feasibility Test, the second choice will be substituted for that particular segment, if the second choice is missing the CAISO will fall back to the most

recently calculated Variable Cost Option default energy bid curve. Finally, adjustments are made to ensure that the staircase bid curve is monotonically increasing.

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

D.4.1 Feasibility Test

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

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

D.4.2 LMP-based DEB Price Calculation

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

D.4.3 Monotonicity Adjustment

Right-To-Left Adjustment

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

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Left-To-Right Adjustment

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

D.5 Variable Cost Option

The Cost-Based DEB will be calculated based on the Incremental Heat Rate curve (for gas fueled units) multiplied by the applicable gas costs[22] 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. If the resource is subject to a greenhouse gas compliance obligation (as indicated by a 'Y' in the GHG_COMPLIANCE_OBLIG field in Master File for resources in the CAISO Control Area), the CAISO will add a greenhouse gas allowance cost. The cost will be calculated per Attachment K, using the projected Greenhouse Gas Allowance Price described in section G.1.3. This amount will then be multiplied by a configurable scalar (e.g., 110%), the

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

DEB Adder, plus a Frequently Mitigated Unit adder if applicable and a Variable Energy Opportunity Cost if applicable, to produce the Cost-Based DEB[23].

D.5.1 Average Heat Rate and Average Cost Curves

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

Non-gas fired resources are required to submit to CAISO in the Master File the Average Cost Curve ($) measured for a minimum 2 and a maximum 11 operating points (MW),), where the first and last operating points refer to the minimum and maximum operating levels, respectively. The Average Cost Curve is the dollar amount of fuel-equivalent costs incurred by resource for providing energy at the operating point for that bid-segment. The average cost curve formed by the ($, MW) pairs is a piece-wise linear between operating points**.**

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

D.5.2 Incremental Heat Rate and Incremental Cost Curves

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

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

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

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

Where:

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

Formula: Incremental Heat Rate Calculation

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

Where:

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

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

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

Formula: Incremental Cost Curve Calculation

D.5.3 Adjustment of Incremental Heat Rate

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

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

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

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

Where:

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

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

Formula: Adjusted Incremental Heat Rate Calculation

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

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

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

Where:

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

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

Formula: Adjusted Incremental Cost Curve Calculation

Examples of this adjustment are provided in Attachment J.

D.5.4 Variable Operation and Maintenance Adder

The Variable Operation and Maintenance (O&M) cost adder is an amount in terms of $/MWh. The exact amount is dependent on technology and/or fuel type of a resource. The default value for the O&M adder is listed in exhibit 4.2. In addition, CAISO will review the default O&M adder values used for DEBs and proxy Minimum Load Cost every three years. RMR Units use the FERC Filed RMR Variable O&M cost. Scheduling Coordinators can also negotiate a custom O&M adder pursuant to Tariff section 39.7.1.1.2 (section D.5 of the BPM) in which case the custom O&M adder will be used to calculate Minimum Load cost as well as Default Energy Bids under the Variable Cost option.

Scalar

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

D.5.6 FMU Bid Adder

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

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

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

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

D.5.7 Left-To-Right Adjustment

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

D.5.8 Summary Examples

Example: Variable Default Energy Bid for Gas-Fired Resource The following example summarizes how the Cost-Based DEB is calculated for an individual segment of a unit's heat rate curve for resource without a greenhouse gas compliance obligation.

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

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

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

= $47.63/MWh

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

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

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

{([IHR * GPI] + O&M + GMC+ [Unit Conversion Factor*IHR*Emission Rate[24]*GHG Cost]) * 1.1} + FMU adder (if eligible) + Variable Energy Opportunity Cost (if eligible)

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

= $54.81/MWh

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

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

For a gas-fired Combined Cycle Gas Turbine (CCGT) with a segment with an 8,000 MMBtu/kWh Incremental Heat Rate, the DEB for that segment would be calculated as follows, given a gas price of $4.50/MMBtu and the proxy gas transport cost were $. 50, making a GPI of $5/MMBtu. The 8,000 Btu/KWh heat rate is converted into MMBtu/MW by multiplying 0.001 to the incremental heat rate. In addition the O&M cost is $2.80/MWh and the GMC adder is $0.50/MWh. If the resource is subject to a greenhouse gas compliance obligation (as indicated by a 'Y' in the GHG_COMPLIANCE_OBLIG field in Master File for resources in the CAISO

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

Control Area), the CAISO will include the greenhouse gas allowance cost in the fuel cost estimate. The cost will be calculated using the Greenhouse Gas Allowance Price described in Attachment K, assume for this scenario the GHG allowance price is $15.34/mtCO2e. Presume that this unit is not eligible for the FMU adder on top of the fuel cost estimate. Based on applying the approach in Attachment N of the Market Instruments Business Practice Manual, the CAISO establishes a Variable Energy Opportunity Cost for the month of $25/MWh[25].

{([IHR * GPI] + O&M + GMC+ [Unit Conversion Factor*IHR*Emission Rate[26]*GHG Cost]) * 1.1} + FMU adder (if eligible) + Variable Energy Opportunity Cost (if eligible)

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

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

= $79.81/MWh

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

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

For a non-gas fired resource with a segment with a $20/MWh Incremental Cost, the DEB for that segment would be calculated as follows. Note – there is no conversion factor applied to the incremental cost since it is in $/MWj. In addition, the CAISO will add the O&M cost (say $2/MWh[27]) and the GMC adder (say $0.50/MWh). Presume that this unit is not eligible for the FMU adder or Variable Energy Opportunity Cost on top of the fuel cost estimate.

{(ICC + O&M + GMC +) * 1.1} + FMU adder (if eligible) + Variable Energy Opportunity Cost (if eligible)

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

= $25.63/MWh

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

[25] Opportunity cost varies based on CAISO processes described in Attachment N of Market Instruments Business Practice Manual.

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

[27] Variable Operation & Maintenance

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

For a non-gas fired resource with a segment of a $20/MW Incremental Cost, the DEB for that segment would be calculated as follows. Note – there is no conversion factor applied to the incremental cost since it is in $/MWh. In addition, the CAISO will add the O&M cost is $2/MWh[28] and the GMC adder is $0.50. If the resource is subject to a greenhouse gas compliance obligation (as indicated by a 'Y' in the GHG_COMPLIANCE_OBLIG field in Master File for resources in the CAISO Control Area), the CAISO will include the greenhouse gas allowance cost in the fuel cost estimate provided the resource has registered its heat rate in the Masterfile. Assume resource has an incremental heat rate of 8000 mmBtu/kWh. The cost will be calculated using the Greenhouse Gas Allowance Price described in Attachment K, assume for this scenario the GHG allowance price is $15.34/mtCO2e. Presume that this unit is not eligible for the FMU adder or Variable Energy Opportunity Cost on top of the fuel cost estimate.

{(ICC + O&M + GMC + [Unit Conversion Factor*IHR*Emission Rate[29]*GHG Cost]) * 1.1} + FMU adder (if eligible) + Variable Energy Opportunity Cost (if eligible){($20 + $2.80 + $0.50 + [8*0.053165*15.34]) * 1.1} + $0 + $0

= $32.80/MWh

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

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

For a non-gas fired resource with a segment with a $20/MW Incremental Cost, the DEB for that segment would be calculated as follows. Note – there is no conversion factor applied to the incremental cost since it is in $/MW. In addition, the CAISO will add the O&M cost is $2/MWh[30] and the GMC adder is $0.50. If the resource is subject to a greenhouse gas compliance obligation (as indicated by a 'Y' in the GHG_COMPLIANCE_OBLIG field in Master File for resources in the CAISO Control Area), the CAISO will include the greenhouse gas allowance cost in the fuel cost estimate. The cost will be calculated using the Greenhouse Gas Allowance

[28] Variable Operation & Maintenance

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

[30] Variable Operation & Maintenance

Price described in Attachment K, assume for this scenario the GHG allowance price is $15.34/mtCO2e provided the resource has registered it's heat rate in the Masterfile. Assume resource has an incremental heat rate of 8000 MMBtu/kWh. Presume that this unit is not eligible for the FMU adder on top of the fuel cost estimate. Based on applying the approach in Attachment N of the Market Instruments Business Practice Manual, the CAISO establishes a Variable Energy Opportunity Cost for the month of $25/MWh[31].

{(ICC + O&M + GMC + [Unit Conversion Factor*IHR*Emission Rate[32]*GHG Cost] (if eligible)) * 1.1} + FMU adder (if eligible) + Variable Energy Opportunity Cost (if eligible)

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

= $57.80/MWh

D.6 Negotiated Rate Option

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

New or modified Opportunity Costs that are based on use-limitations must be established pursuant to CAISO Tariff section 30.4 and the businesses processes set forth in the Business Practice Manual. Scheduling Coordinators may, however, submit documentation of Opportunity Costs that are not based on use limitations for potential inclusion in the negotiated Default Energy Bid. D. 6.1 Information Needed in order to establish a Default Energy Bid for a Generating Unit based on the Negotiated Rate Option, the Scheduling Coordinator for the Generating Unit must provide the CAISO with the following information:

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

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

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

[31] Opportunity cost varies based on CAISO processes described in Attachment N of Market Instruments Business Practice Manual.

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

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

After receipt of a request to establish a bid under the Negotiated Rate Option, the CAISOs 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 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. All information provided by a Scheduling Coordinator shall be subject to confidentiality provisions of the CAISO Tariff.

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

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

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

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

1. The DEB is modified by FERC;

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

3.The CAISO or Scheduling Coordinator provides written notification that the DEB is no longer acceptable for use under the Negotiated Rate Option. For example, if the DEB

expires, is terminated, or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

D.6.4 Applicable DEB Pending Agreement Over Negotiated Rate Option

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

1. The other DEB options provided in 39.7.1 (i.e., Cost-Based Option or LMP-Option); or
2. A temporary DEB established by the CAISO.

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

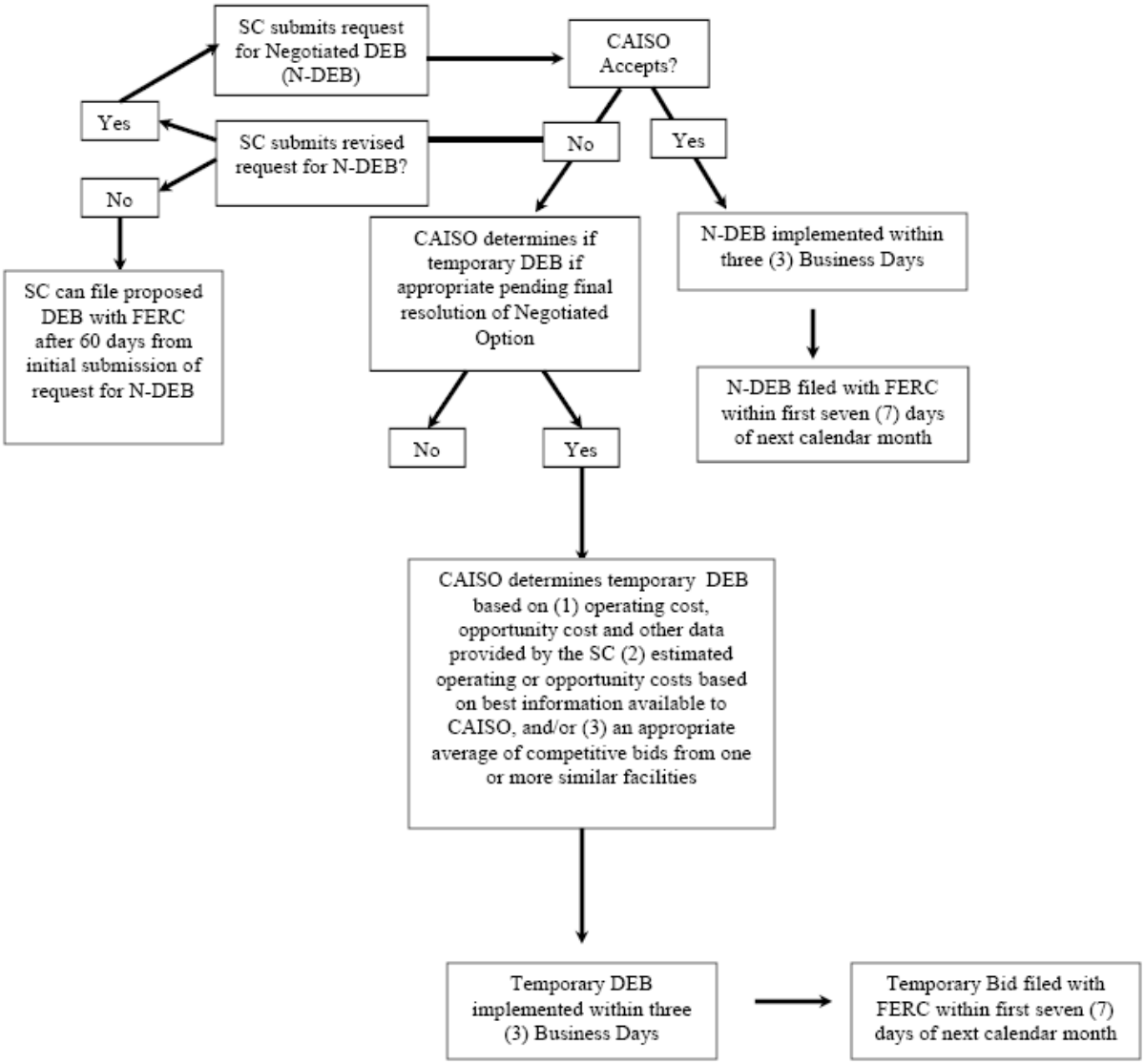
Any modified DEB established by the CAISO would be based on the same criteria the CAISO would use to assess bid levels or formulas proposed by Scheduling Coordinators:

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

D.6.5 Dispute Resolution

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

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



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

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

1. *Change in 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.6.6 NDEBS that include opportunity costs as of April 1, 2019

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

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

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

D.7 RMR Units

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

The Bids utilized in the MPM process for RMR Units will be the RMR Proxy Bids for the RMR contractual capacity. RMR units are not eligible to receive the 10% adder for their RMR contract capacity. For available capacity in excess of the MNDC the Scheduling Coordinator representing the RMR unit must rank order their calculation preference between the same three methodologies, namely LMP Option, Variable Cost Option and Negotiated Rate Option. This preference will then apply to the non-RMR capacity between the MNDC and the PMax of the unit. The CAISO 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 CAISO.

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

F Example of Variable Cost Option Bid Calculation

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.

Operating Point (n)	Operating Level	Average Heat Rate
1	164	7,643
2	298	7,485
3	340	7,643
4	480	7,000
5	590	7,485

Step1. 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.

Operating Point, n	Operating Level	Average Heat Rate	Segment	Initial Incremental
1	164	7,643	1	7,292
2	298	7,485	2	8,764
3	340	7,643	3	5,438
4	480	7,000	4	9,601
5	590	7,485		

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.

$$OperatingLevel_1\% = \frac{OperatingLevel_1}{P\max} = \frac{164}{590} = 27.8\%$$

$$OperatingLevel_2\% = \frac{OperatingLevel_2}{P\max} = \frac{298}{590} = 50.5\%$$

$$OperatingLevel_3\% = \frac{OperatingLevel_3}{P\max} = \frac{340}{590} = 57.6\%$$

$$OperatingLevel_4\% = \frac{OperatingLevel_4}{P\max} = \frac{480}{590} = 81.4\%$$

$$OperatingLevel_5\% = \frac{OperatingLevel_5}{P\max} = \frac{590}{590} = 100\%$$

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:

$$IHR_{S1}^{adjusted} = \min(IHR_{S1}^{ini}, Cap_{S1}) = \min(7292, 7643) = 7292 \text{ Btu/kWh}$$

$$IHR_{S2}^{adjusted} = \min(IHR_{S2}^{ini}, Cap_{S2}) = \min(8764, 7643) = 7643 \text{ Btu/kWh}$$

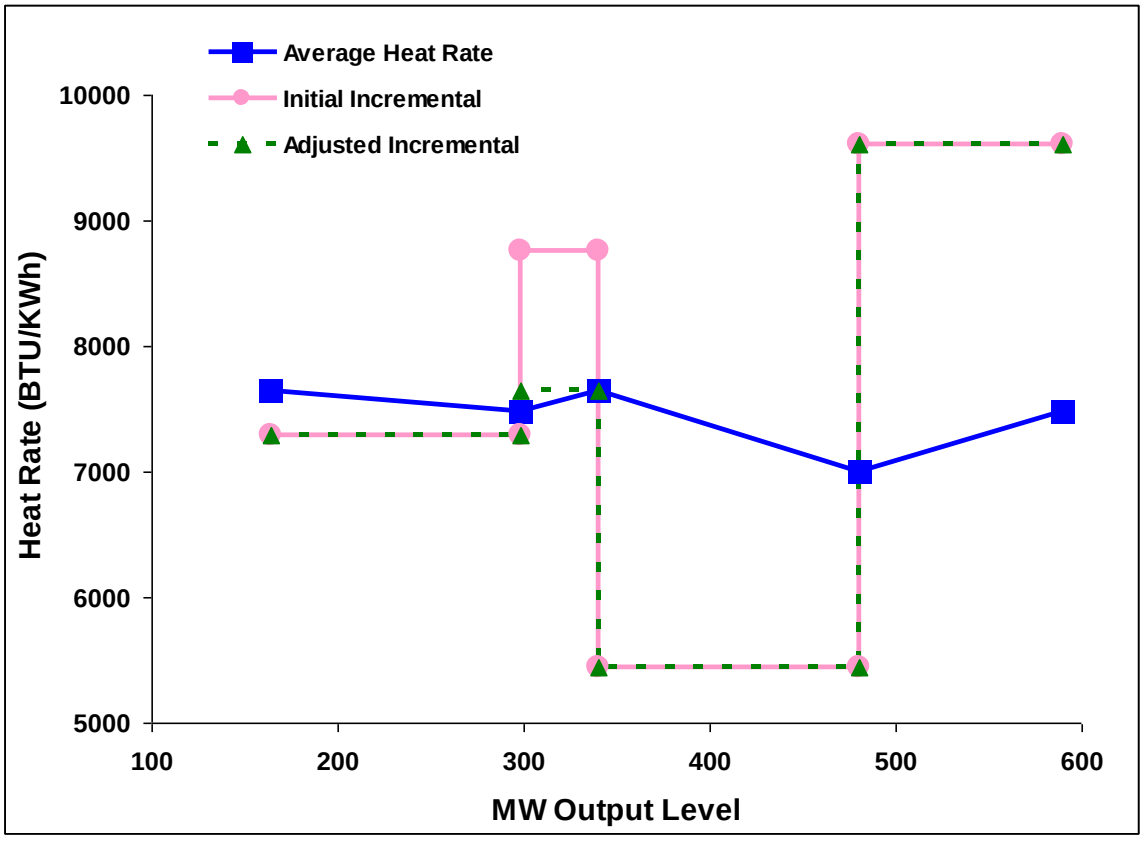
$$IHR_{S3}^{adjusted} = \min(IHR_{S3}^{ini}, Cap_{S3}) = \min(5438, 7643) = 5438 \text{ Btu/kWh}$$

$$IHR_{S4}^{adjusted} = \min(IHR_{S4}^{ini}, Cap_{S4}_Not_Applicable_OperatingLevel_4 = 81.4\% \geq 80\%)$$

$$= 9601 \text{ Btu/kWh}$$

Results of these calculations are summarized in the table and figure below.

Operating Point (n)	Operating Level	Average Heat Rate	Segment	Initial Incremental Heat Rate	Cap	Operating Level % of Pmax	Adjusted Incremental Heat Rate
1	164	7643	1	7292	7643	27.8%	7292
2	298	7485	2	8764	7643	50.5%	7643
3	340	7643	3	5438	7643	57.6%	5438
4	480	7000	4	9601	7485	81.4%	9601
5	590	7485				100.0%	



Step 3. Calculate Incremental Cost Curve

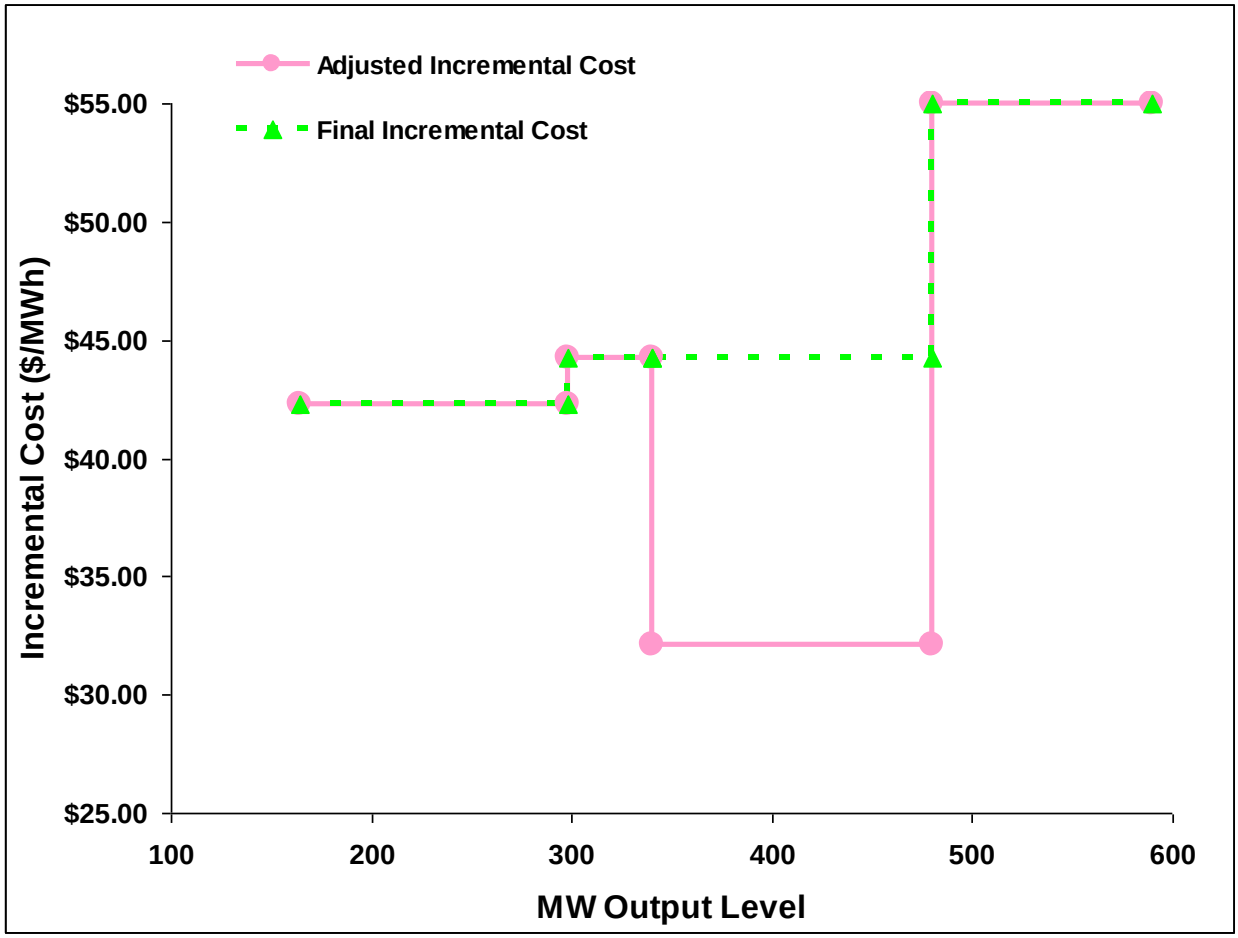
The adjusted incremental heat rate curve is then combined with an O&M cost adder and a Grid Management Charge (GMC) adder, made up of the Market Services Charge and System Operations Charge components and a third value representing the Bid Segment Fee component divided by the bid segment MW size, to 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.

Segment	Operating Range	Adjusted Incremental Heat Rate	Incremental Cost	Incremental Cost After Right-to-Left Adjustment
1	164-297	7292	$38.96	$38.96
2	298-339	7643	$40.72	$40.72
3	340-479	5438	$29.69	$40.72
4	480-589	9601	$50.51	$50.51



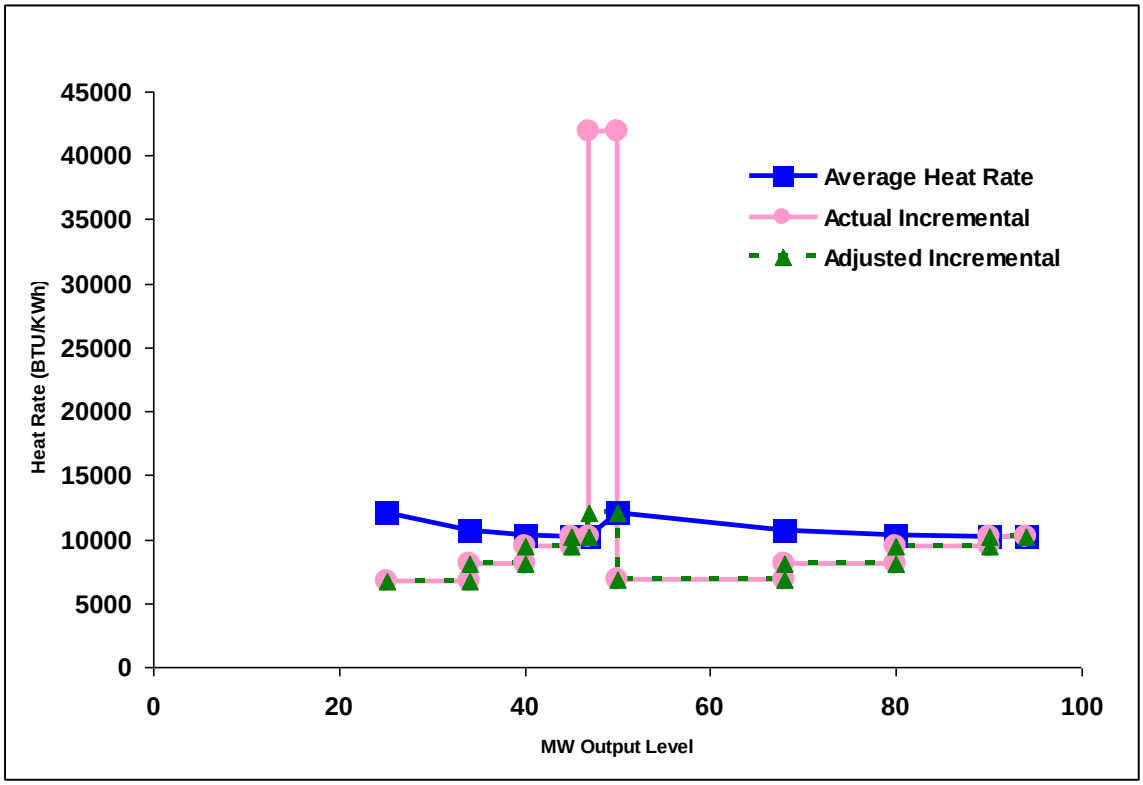
Note, if the resource is subject to a greenhouse gas compliance obligation as indicated in the Master File, the CAISO will add to this curve an incremental energy curve representing the cost of meeting that obligation. To cover that case, this example is continued in Appendix Attachment K.

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.

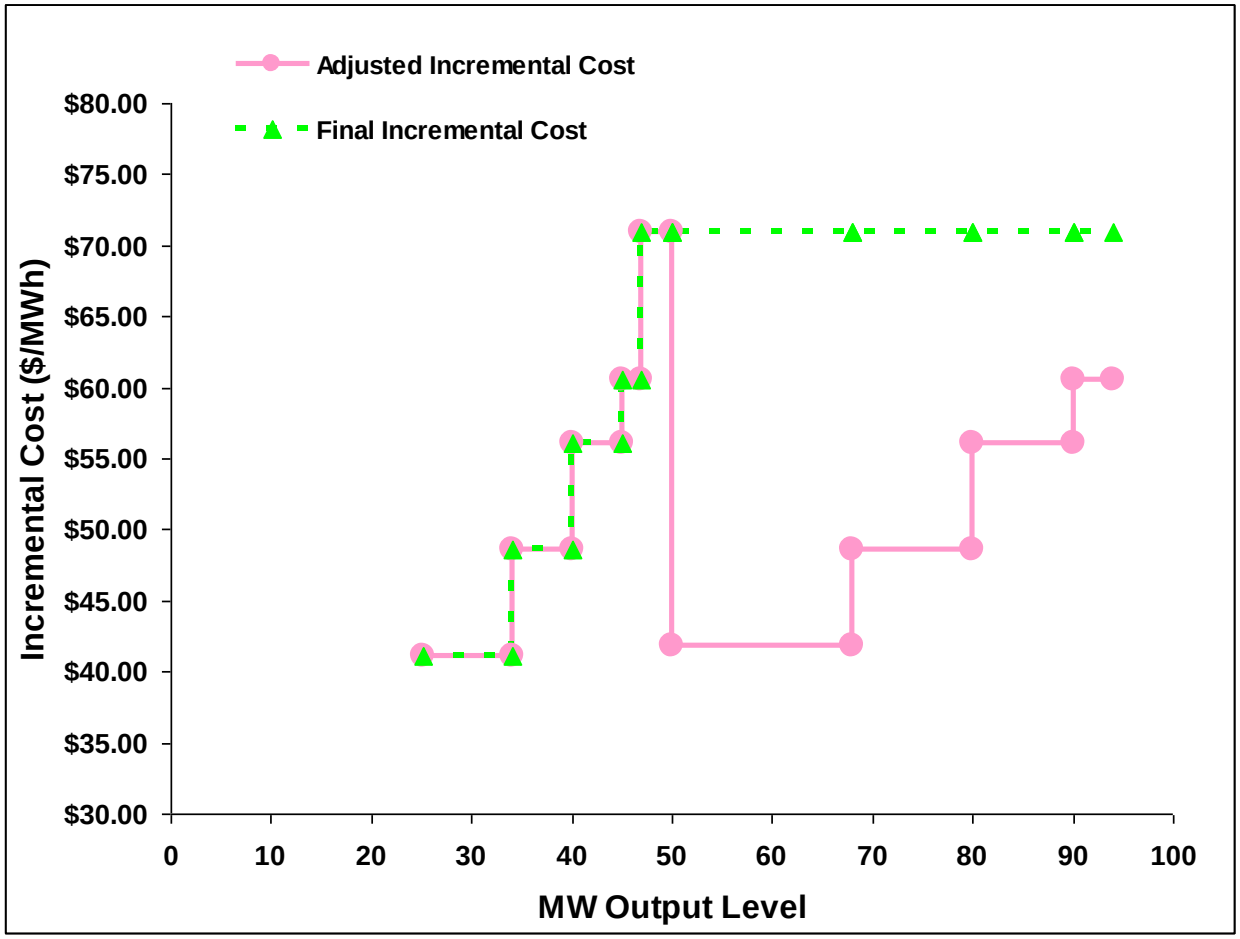
Results of heat rates calculations described in Steps 1 and 2 of Example 1 are shown in the table and figure below.

Operating Point, n	Operating Level (MW)	Average Heat Rate	Segment	Incremental Heat Rate	Cap	Operating Level % of Pmax	Adjusted Incremental Heat Rate
1	25	12100	1	6679	12100	26.8%	6679
2	34	10700	2	8033	10700	36.2%	8033
3	40	10300	3	9400	10300	42.6%	9400
4	45	10200	4	10200	10200	47.9%	10200
5	47	10200	5	41867	12100	50.0%	12100
6	50	12100	6	6811	12100	53.2%	6811
7	68	10700	7	8033	10700	72.3%	8033
8	80	10300	8	9400	10300	**85.1%**	9400
9	90	10200	9	10200	10200	**95.7%**	10200
10	94	10200				**100.0%**	



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.

Segment	Operating Range	Adjusted Incremental Heat Rate	Incremental Cost	Incremental Cost After Right-to-Left Adjustment
1	25-33	6679	$37.90	$37.90
2	34-39	8033	$44.67	$44.67
3	40-44	9400	$51.50	$51.50
4	45-46	10200	$55.50	$55.50
5	47-49	12100	$65.00	$65.00
6	50-67	6811	$38.56	$65.00
7	68-79	8033	$44.67	$65.00
8	80-89	9400	$51.50	$65.00
9	90-94	10200	$55.50	$65.00


Adjusted Incremental Cost
Final Incremental Cost
$80.00
$75.00
$70.00
$65.00
$60.00
$55.00
$50.00
$45.00
$40.00
$35.00
$30.00
Incremental Cost ($/MWh)
0
10
20
30
40
50
60
70
80
90
100
MW Output Level

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 fewer than 12 months of LMP data and approved use-limitations on register in the Master File Use Limit Plan Data Template are eligible to select the Registered Cost Option for up to 14 months after the resource is established in the market, pursuant to tariff section 30.4.1.2Once the CAISO has 12 months of LMP date, the CAISO will utilize a two month period to calculate the opportunity cost. If the CAISO can identify a comparable PNode or APNode to the new resource's node to use to determine forecasted prices needed in the calculation of opportunity costs, the CAISO will offer an alternative transitional solution to the Scheduling Coordinator where the resource can elect the Proxy Cost option with an opportunity cost. The Scheduling Coordinator must elect the option it prefers through its Generator Resource Data Template. See Attachment N of the Market Instruments BPM for details on the methodology for establishing opportunity costs for use-limited resources eligible for opportunity cost pursuant to tariff section 30.4.1.1.6.1.2. See Attachment H of the Market Instruments BPM 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[33] 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 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.

[33] See Attachment H for transition cost calculations.

- 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.

Automatic Switching of Cost Basis from Registered to Proxy

As of beginning of the 14th month after a new resource with approved use-limitations on register in the Master File Use Limit Plan Data Template is established in the market, the resource is no longer eligible to select Registered Cost and must move to the Proxy Cost methodology. The CAISO will automatically switch the cost basis of such a resource to Proxy Cost methodology in the Master File at the end of the 14th month after the date the resource was established in the market.

G.1.1 Natural Gas Units

G.1.1.1 Maximum Registered Start-up Costs

The maximum Start-up costs that may be approved for gas-fired units under the Registered Cost Option are based on the resource's actual unit-specific performance parameters in the

Master File. The projected Start-up costs will be calculated by combining the unit's Startup fuel curve and the projected gas price index, and 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 multiplying the MWh energy input with the Electricity Price Index[34], 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, the CAISO will add a major maintenance cost adder (MMA). See Attachment L for details.

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 Electricity Price) + (PMin x Start-Up Time Period in min / 60 min/hour x GMC adder / 2)

Gas Price = 8.50/MMBtu
Gas Price Multiplier = 10

Electricity Price $_{\text{Wholesale}}$ = Gas Price x Gas Price Multiplier
Electricity Price $_{\text{Retail}}$ = Electricity Price

Example of start-up cost calculation using a wholesale EPI (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)

[34] See Attachment M of the Market Instruments BPM for details.

= 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 Electricity Price) + (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_2e
GHG Emission Rate = 0.053165 mtCO_2e /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 / (60minutes/hour)) x \$0.50/MWh / 2) + (1,083 MMBtu x 0.053165 mtCO_2e /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).
Start-Up Cost = \$11,838.74 + major maintenance cost adder
= \$11,838.74 + 800.98
= \$12,639.72
= \$12,640 (rounded)

Table G1. Example of Projected Start-up Cost and Maximum Registered Cost Bid Calculation (Gas Price = \$8.50/MMBtu)

	Cooling Time (minutes)	Start-Up Time (minutes)	Start-Up Fuel (MMBtu)	Start-Up Energy (MWh)	Start-Up Cost w/o GHG/MMA ($)	Start-Up Cost with GHG & MMA ($)	Max Start-Up Bid w/o GHG/MMA ($)	Max Start-Up Bid with GHG & MMA ($)

Hot	0	600	1,083	20	$10,956	$12,640	$16,433	$18,960
Warm	240	1390	1,633	40	$17,396	$19,529	$26,059	$29,294
Cold	480	1400	2,000	60	$22,217	$24,649	$33,325	$36,973

G.1.1.2 Maximum Registered 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, Operation and Maintenance (O&M) adder consistent with Exhibit 4-2 unless a custom O&M adder is negotiated with the CAISO, 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 for resources within the CAISO Control Area), 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 x 14,000Btu/kWh x 20MW x $8.50/MMBtu) + ($4/MWh[35] x 20MW) + ($0.50/MWh x 20MW)

[35] This example assumes a $4/MWh O&M adder.

= ($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 $mtCO_2e$ /MMBtu
GHG Allowance Price = $15.34/$mtCO_2e$

= (0.001 x 14,000Btu/kWh x 20MW x $8.50/MMBtu) + ($4/MWh * 20MW) + ($0.50/MWh x 20MW) + (20MW x 0.001 x 14,000Btu/kWh x 0.053165 mtCO2/MMBtu x 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

Minimum Operating Level (MW)	Heat Rate (MBtu/ MWh)	O&M Cost ($/MWh)	Minimum Load Cost ($)	GHG Allowance Cost & MMA ($/MWh)	Minimum Load Cost with GHG & MMA ($)	Max MLC Bid w/o GHG/MMA ($)	Max MLC Bid with GHG & MMA ($)
20	14,000	4	$2,470	$333	$2,803	$3,705	$4,205

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 trading hub associated with the resource-specific fuel region registered in Master File[36] are calculated, using data for the first 21 trade dates in the month.

Consistent with the approach used by the CAISO to calculate the GPI for daily spot market prices used to calculate DEBs and commitment cost bids under the Proxy Cost option, average monthly price for futures are ultimately used for units based on the natural gas trading hub defined in the fuel region associated with the resource in Master File.

The next step is to combine the average Henry Hub price and the average basis swap price for each of the natural gas trading hub delivery points for each month.

Consistent with the approach used by the CAISO to calculate the GPI for daily spot market prices, the final step is to add the appropriate intra-state transport rateThe CAISO uses the applicable transportation rate to reflect the delivered price of gas based on the transport rate components defined for the resource-specific fuel region registered in Master File.

The source of gas price data used in this calculation will be the commodity price indices from SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily, or Natural Gas Intelligence Daily publications, or, if necessary, another available source of closing prices for natural gas futures contracts for each trade date.

[36] See Attachment C of Market Instruments BPM for a link to existing list of fuel regions.

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 for resources within the CAISO Control Area 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.

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 fuel or fuel equivalent cost information submitted and validated by the CAISO for each unit under the requirements for the Proxy Cost Option. The CAISO will add to the fuel or fuel equivalent costs in Master File 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, greenhouse gas allowance costs if applicable, and major maintenance costs if applicable. The GMC 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 for resources within

the CAISO Control Area), the CAISO shall 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 Master File values for the parameters used in Proxy Start-Up Costs and Proxy Minimum Load Cost, as described in Attachment B. Multi-stage generating resources must also submit Resource Data Template values for the parameters used in proxy 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[37] 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 plus applicable transportation rates 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 for resources within the CAISO Control Area), 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.

[37] 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. However, RTM submissions will not be used for the RTM trade hour if the resource received a financially binding integrated forward market award or a binding residual unit commitment start-up instruction in the DAM; instead, 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 plus a Start-Up Opportunity Cost if applicable.

For multi-stage generating resources, a Scheduling Coordinator may bid Transition Costs daily.[38] 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 plus a transition opportunity cost if applicable. If the Scheduling Coordinator does not bid, the CAISO will generate daily bids based on the calculated Proxy Costs plus any applicable Start-Up Opportunity Cost.

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.

Proxy 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 Proxy Start-Up Cost calculation (first Start-Up segment):

[38] See Attachment H for transition cost calculations.

Proxy 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)

Proxy Start-Up Costs including a GHG Compliance Obligation:

Proxy 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 = $15.34/mt$CO_2$e
GHG Emission Rate = 0.053165 mtCO_2e /MMBtu

Example of proxy Start-Up Cost:
Proxy 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_2e /MMBtu x $15.34)
= (9,205.5) + (1,600) + (50) + (883.24)
= 11,738.74
= 11,739 (rounded)

Proxy Start-Up Costs including a GHG Compliance Obligation and a major maintenance cost adder:

The major maintenance cost adder is a single line item that is added to the proxy 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).
Proxy 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 Proxy Start-up Cost and Start-up Cost Bid Cap (Gas Price = $8.50/MMBtu, EPI = $80/MWh, Headroom Scalar = 125%, Start-up Opportunity Cost = $2,000/start)

	Cooling Time (minutes)	Start-Up Time (minutes)	Start-Up Fuel (MMBtu)	Start-Up Energy (MWh)	Proxy Start-Up Cost w/o GHG/MMA ($)	Proxy Start-Up Cost with GHG & MMA ($)	Start-Up Bid Cap with Headroom Scalar ($)	Start-Up Bid Cap with Headroom Scalar and Opportunity Cost ($)
Hot	0	600	1,083	20	$10,856	$12,540	$15,675	$17,675
Warm	240	1390	1,633	40	$17,196	$19,329	$24,161	$26,161
Cold	480	1400	2,000	60	$21,917	$24,349	$30,436	$32,436

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 plus applicable transportation rates 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 for resources within the CAISO Control Area), 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 in either DAM or RTM. However, RTM submissions will not be used for the RTM trade hour if the resource received a financially binding integrated forward market award or a binding residual unit commitment start-up instruction in the DAM, instead 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 plus a Minimum Load Opportunity Cost if applicable. If the Scheduling Coordinator does not bid, the CAISO will generate daily

bids based on the calculated Proxy Costs plus any applicable Minimum Load Opportunity Cost. The calculation and an example are provided below.

Example: Proxy Minimum Load Cost Calculation and Bid Cap for Gas-Fired Resource

Proxy 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 index = 8.50/MMBtu
O&M adder = $4/MWh
GMC adder = $0.50/MWh

Proxy Minimum Load Cost = (0.001 x 14,000Btu/kWh x 20MW x $8.50/MMBtu) + ($4/MWh[39] x 20MW) + ($0.50/MWh x 20MW)

= ($2,380) + ($80) + ($10)

= $2,470

Proxy 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 $mtCO_2e$ /MMBtu
GHG Allowance Price = $15.34/$mtCO_2e$

= (0.001 x 14,000Btu/kWh x 20MW x $8.50/MMBtu) + ($4/MWh * 20MW) + ($0.50/MWh x 20MW) + (20MW x 0.001 x 14,000Btu/kWh x 0.053165 mtCO2/MMBtu x 15.34)
= ($2,380) + ($80) + ($10) + ($228)
= $2,698

Proxy 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.

[39] This example assumes a $4/MWh O&M adder.

Proxy Minimum Load Cost = $2,695 + major maintenance cost adder
= $2,698 + 105
= $2,803

Table G4. Example of Proxy Minimum Load Cost and Minimum Load Bid Cap (Gas Price Index = $8.50/MMBtu, Headroom Scalar = 125%, Minimum Load Opportunity Cost = $500/run-hour)

Minimum Operating Level (MW)	Heat Rate (MBtu/ MWh)	O&M Cost ($/MWh)	Minimum Load Cost ($)	GHG Allowance Cost & MMA ($/MWh)	Proxy Minimum Load Cost with GHG & MMA ($)	Minimum Load Bid Cap with Headroom Scalar ($)	Minimum Load Bid Cap with Headroom Scalar and Opportunity Cost ($)
20	14,000	4	$2,470	$333	$2,803	$3,504	$4,004

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 fuel or fuel equivalent cost information submitted and validated by the CAISO for each unit under the requirements for the Proxy Cost Option. The CAISO will add to the fuel or fuel equivalent costs in Master File 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, greenhouse gas allowance costs if applicable, and major maintenance costs if applicable. The GMC adder is calculated the same as for gas-fired units explained above.

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 for resources within the CAISO Control Area), 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.

A Scheduling Coordinator may bid Start-Up, Minimum Load, and Transition Costs daily in either DAM or RTM. However, RTM submissions will not be used for the RTM trade hour if the resource received a financially binding integrated forward market award or a binding residual unit commitment start-up instruction in the DAM; instead, the DAM Daily Components will be copied to the RTM bid. For multi-stage generating resources, a Scheduling Coordinator may bid Transition Costs daily.[40] If the Scheduling Coordinator does not bid, the CAISO will generate daily bids based on the calculated Proxy Costs.

Start-Up, Minimum Load, and Transition Cost Bids under the Proxy Cost Option may not exceed 125 percent of the unit's Start-Up, Minimum Load, and Transition Costs under the Proxy Cost Option plus any applicable Start-Up, Minimum Load, or Transition Opportunity Costs.

[40] See Attachment H for transition cost calculations.

Attachment H

Transition Costs for Multi-Stage Generator Resources

H Transition Costs for Multi-Stage Generator Resources

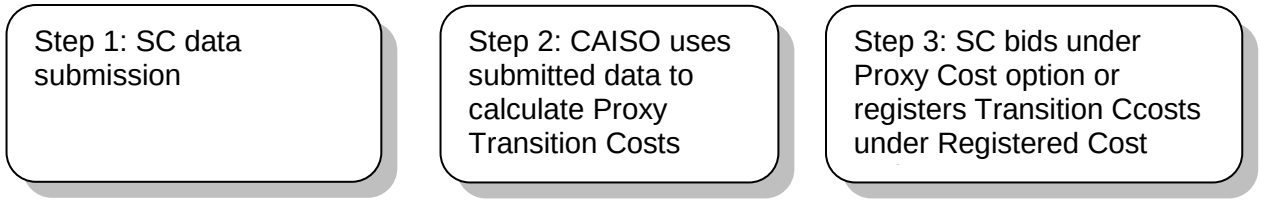
Transition Costs are a type of Start-Up Cost specific to multi-stage generators. Transition Costs can be thought of as the costs to "start" a configuration (or conversely the cost savings to "shut down" a configuration). The CAISO uses different terminology to differentiate between changes in configuration when the resource is already "On" versus a plant-level Start-Uup, 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.

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 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 cCsts 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).[41] 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 Cost and Registered Ccost options. Please see Attachment G for Proxy Cost 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.

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

[41] Note that the CAISO tariff does not differentiate between Sstart-Up and indirect Sstart-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.

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) as 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 (from and to) configurations for feasible transitions plus a transition Opportunity Cost if applicable.

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-Up Costs for feasible transitions plus a transition Opportunity Cost if applicable 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 plus a transition Opportunity Cost if applicable. Start-Up Cost and indirect Start-Up Cost bid caps will be calculated based on the Proxy Cost 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.

Scheduling Coordinators under the Proxy Cost option can bid daily up to 125 percent of the proxy transition cost excluding the transition cost opportunity cost plus 100 percent of the

transition cost opportunity cost in the proxy cost if applicable. 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 of the Market Instruments BPM. For Multi-Stage Generators under the Proxy Cost Option that have registered start use limitations in the ULPDT and depending on the outcome of the CAISO procedures to establish opportunity costs pursuant to Section 30.4.1.1.6.1.2, the Multi-Stage Generator may also have transition opportunity costs in its bid cap. In cases where a transition between configurations is considered a start to which the start limitation applies, a start opportunity cost will be calculated for each to-configuration. For feasible transitions, the CAISO will set the transition bid cap for the transition as 125% of the difference between the 'To Configuration' and 'From Configuration' start proxy costs plus the start-up opportunity cost of the 'To Configuration'.

The transition cost bid cap under proxy cost option is calculated as follows:

$$TC_{From \rightarrow To} = [1.25 * (SUC_{To} - SUC_{From})] + SU_OC_{To}$$

Where,

$TC_{From->To}$	Transition proxy cost bid cap for transition from from-config to to-config
SUC_{To}	Proxy start-up cost of to-configuration
SUC_{From}	Proxy start-up cost of from-configuration
SU_OC_{To}	Start-up opportunity cost of to-configuration

For MSG configuration starts and transitions, the start-up opportunity cost is calculated per implied start for each configuration. This value is multiplied by the number of implied starts registered in the Generator Resource Data Template to derive the opportunity costs that will be included in the start-up cost bid cap or transition cost bid cap, as applicable.

Scheduling Coordinators eligible for the Registered Cost option can register transition costs of up to a 150 percent cap of projected transition costs, which do not include a transition opportunity cost.

Step 3: Scheduling Coordinator subject to daily bids under Proxy Cost option 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 Proxy Cost and Registered Cost options can bid or register Transition Costs subject to the Proxy Cost Bid Cap and Registered Cost Bid Cap respectively. The Proxy Cost and Registered Cost Bid Caps are described in Step 2. A Scheduling Coordinator may not change its Registered Cost or Proxy Cost election for a minimum 30-day period. The Registered Cost option has slightly different inputs from 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

Step 1: SC data submission

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 H1
Proxy Start-Up and indirect Proxy Start-Up Cost calculation: peaker or steam turbine

Config ID	Configuration	Heat input (MMBtu)	Gas price ($/MMBtu)	GHG price	GHG emission rate	Major maint. adder	Config Pmin	Config startup time	GMC	Start-Up energy (MWh)	Elec. price index ($/MWh)
UnitA_1	1 – Startable	80	$4.00	$12.00	0.053963	$250	50	20	$0.38	20	$1.00
UnitA_2	2 – NOT startable	160	$4.00	$12.00	0.053963	$550	100	20	$0.38	20	$1.00
UnitA_3	3 – Startable	240	$4.00	$12.00	0.053963	$1,000	150	20	$0.38	20	$1.00
UnitA_4	4 – NOT startable	320	$4.00	$12.00	0.053963	$1,500	200	20	$0.38	20	$1.00

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 Resource Data

Template values for the parameters used in Proxy Start-Up Costs or Proxy Transition Costs for certain start-up or indirect start-up costs may result in a lower or zero transition cost.

Table H2
Proxy Start-Up and indirect Proxy Start-Up Cost calculation for missing data: peaker or steam turbine

Config ID	Configuration	Heat input (MMBtu)	Gas price ($/MMBtu)	GHG price	GHG emission rate	Major maint. adder	Config Pmin	Config startup time	GMC	Start-Up energy (MWh)	Elec. price index ($/MWh)
UnitA_1	1 – Startable	80	$4.00	$12.00	0.053963	$250	50	20	$0.38	20	$1.00
UnitA_2	2 – NOT startable	80	$4.00	$12.00	0.053963	$250	50	20	$0.38	20	$1.00
UnitA_3	3 – Startable	240	$4.00	$12.00	0.053963	$1,000	150	20	$0.38	20	$1.00
UnitA_4	4 – NOT startable	240	$4.00	$12.00	0.053963	$1,000	150	20	$0.38	20	$1.00

Step 2: CAISO uses submitted data to calculate Proxy Ttansition Costs

Table H3 reproduces the same inputs as Table H1. The last column in blue has been added to calculate the Proxy Start-Up or indirect Proxy Start-Up cost:

Proxy 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
Proxy Start-Up and indirect Proxy Start-Up Cost calculation: peaker or steam turbine

Config ID	Configuration	Heat input (MMBtu)	Gas price ($/MMBtu)	GHG price	GHG emission rate	Major maint. adder	Config Pmin	Config startup time	GMC	Start-Up energy (MWh)	Elec. price index ($/MWh)	Cost
UnitA_1	1 – Startable	80	$4.00	$12.00	0.053963	$250	50	20	$0.38	20	$1.00	$645
UnitA_2	2 – NOT startable	160	$4.00	$12.00	0.053963	$550	100	20	$0.38	20	$1.00	$1,320
UnitA_3	3 – Startable	240	$4.00	$12.00	0.053963	$1,000	150	20	$0.38	20	$1.00	$2,145
UnitA_4	4 – NOT startable	320	$4.00	$12.00	0.053963	$1,500	200	20	$0.38	20	$1.00	$3,020

Table H4 shows the Proxy Transition Ccosts based on the Start-Up and indirect Start-Up Costs shown in Table H3. The Proxy Transition Ccosts are equal to 100 percent of the Proxy Start-Up Costs. All of the Proxy Transition Costs are calculated as the difference between the "To" configuration and "From" configuration Proxy Start-Up Cost and indirect Proxy Start-Up Costs. For example, the Start-Up Ccost 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
Proxy Transition Cost: peaker or steam turbine

		"To" configuration			
		UnitA_1	UnitA_2	UnitA-3	UnitA_4
"From" configuration	UnitA_1		$675	$1,500	$2,375
	UnitA_2			$825	n/a
	UnitA_3				$875
	UnitA_4				

Assuming the resource has a $0 start-up opportunity cost, the transition cost bid cap under the Proxy Cost option for the transition from configuration 1 to configuration 2 is calculated as follows:

= [1.25*$675] +$0

= $843.75

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 Resource Data Template values for the parameters used in Proxy Start-Up Costs or Proxy Transition Costs for configurations 2 and 4 (and the CAISO using information from configurations 1 and 3, respectively), is a zero Proxy Transition Cost calculated for transition paths C1 to C2 and C3 to C4, reduced Transition Cost from C1 to C4, and an increase in Ttransition 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
Proxy Transition Cost calculation for missing data: peaker or steam turbine

		"To" configuration			
		UnitA_1	UnitA_2	UnitA-3	UnitA_4
"From" configuration	UnitA_1		$0	$1,500	$1,500
	UnitA_2			$1,500	n/a
	UnitA_3				$0
	UnitA_4				

Step 3: SC bids under Proxy Cost option 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 Proxy Cost and Registered Cost options can bid or register Transition Costs subject to the Proxy Cost Bid Cap and Registered Cost Bid Cap respectively. The Proxy Cost and Registered Cost Bid Caps are described in Step 2. A Scheduling Coordinator may not change its Registered Cost or Proxy Cost election for a minimum 30-day period. The Registered Cost option has slightly different inputs from 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 Pmin of configuration 1 (200 MW) through to the Pmin of 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 Pmin, and Sstart-Up Time for each configuration. The heat input is the amount to reach the Pmin of 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 H6
Proxy Start-Up and indirect Proxy Start-Up Cost calculation: duct firing

Config ID	Configuration	Heat input (MMBtu)	Gas price ($/MMBtu)	GHG price	GHG emission rate	Major maint. Adder	Config Pmin	Config startup time	GMC	Start-Up energy (MWh)	Elec. price index ($/MWh)
UnitB_1X1	1 – Startable	1,500	$4.00	$12.00	0.053963	$11,590	200	60	$0.38	20	$1.00
UnitB_1X1DF	2 – NOT startable	1,550	$4.00	$12.00	0.053963	$11,590	250	60	$0.38	20	$1.00
UnitB_2X1	3 – Startable	2,500	$4.00	$12.00	0.053963	$23,180	400	60	$0.38	20	$1.00
UnitB_2X1DF	4 – NOT startable	2,550	$4.00	$12.00	0.053963	$23,180	450	60	$0.38	20	$1.00

Table H6 assumes that the CAISO has enough information from the Scheduling Coordinator to calculate each Proxy Start-Uup and indirect Proxy 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 Resource Data Template values for the parameters used in Proxy Start-Up Costs or Proxy Transition Costs for

certain Start-Up or indirect Start-Up Costs parameters in the Master File may result in a lower or zero transition cost.

Table H7
Proxy Start-Up and indirect Proxy Start-Up Ccost calculation for missing data: duct firing

Config ID	Configuration	Heat input (MMBtu)	Gas price ($/MMBtu)	GHG price	GHG emission rate	Major maint. Adder	Config Pmin	Config startup time	GMC	Start-Up energy (MWh)	Elec. price index ($/MWh)
UnitB_1X1	1 – Startable	1,500	$4.00	$12.00	0.053963	$11,590	200	60	$0.38	20	$1.00
UnitB_1X1DF	2 – NOT startable	1,550	$4.00	$12.00	0.053963	$11,590	200	60	$0.38	20	$1.00
UnitB_2X1	3 – Startable	2,500	$4.00	$12.00	0.053963	$23,180	400	60	$0.38	20	$1.00
UnitB_2X1DF	4 – NOT startable	2,550	$4.00	$12.00	0.053963	$23,180	400	60	$0.38	20	$1.00

Step 2: CAISO uses submitted data to calculate Proxy Transition Costs

Table H8 reproduces the same inputs as Table H6. The last column in blue calculates the Proxy Start-Up or indirect Proxy Start-Up Cost:

Proxy 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 H8
Proxy Start-Up and indirect Proxy Start-Up Cost calculation: duct firing

Config ID	Configuration	Heat input (MMBtu)	Gas price ($/MMBtu)	GHG price	GHG emission rate	Major maint. adder	Config Pmin	Config startup time	GMC	Start-Up energy (MWh)	Elec. price index ($/MWh)	Cost
UnitB_1X1	1 – Startable	1,500	$4.00	$12.00	0.053963	$11,590	200	60	$0.38	20	$1.00	$18,604
UnitB_1X1DF	2 – NOT startable	1,550	$4.00	$12.00	0.053963	$11,590	250	60	$0.38	20	$1.00	$18,845
UnitB_2X1	3 – Startable	2,500	$4.00	$12.00	0.053963	$23,180	400	60	$0.38	20	$1.00	$34,869
UnitB_2X1DF	4 – NOT startable	2,550	$4.00	$12.00	0.053963	$23,180	450	60	$0.38	20	$1.00	$35,110

Table H9 shows the Proxy Transition Costs based on the Start-Up and indirect Proxy Start-Up Costs shown in Table H8. The Proxy 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 Proxy Start-Up and indirect Proxy 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 Proxy 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 Cost 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 H9
Proxy Transition Cost calculation: duct firing

		"To" configuration			
		UnitA_1	UnitA_2	UnitA-3	UnitA_4
"From" configuration	UnitA_1		$241	$16,265	$16,507
	UnitA_2			$16,024	n/a
	UnitA_3				$241
	UnitA_4				

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 Resource Data Template values for the parameters used in Proxy Start-Up Costs or Proxy Transition Costs 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
Proxy Transition Cost calculation for missing data: duct firing

		"To" configuration			
		UnitA_1	UnitA_2	UnitA-3	UnitA_4
"From" configuration	UnitA_1		$0	$16,265	$16,265
	UnitA_2			$16,265	n/a
	UnitA_3				$0
	UnitA_4				

Step 3: SC bids under Proxy Cost option 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 Proxy Cost and Registered Cost options can bid or register Transition Costs subject to the Proxy Cost Bid Cap and Registered Cost Bid Cap respectively. The Proxy Cost and Registered Cost Bid Caps are described in Step 2.A scheduling coordinator may not change its Registered Cost or Proxy Cost election for a minimum 30-day period. The Registered Cost option has slightly different inputs to the Pproxy Ccost 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 Cost 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 H11
Proxy Start-Up Cost calculation: non-natural gas-fired, turbine-based and thermal

Config ID	Configuration	Non-nat gas start cost ($)	Heat input (MMBtu)	GHG price	GHG emission rate	Major maint. adder	Config Pmin	Config startup time	GMC	Start-Up energy (MWh)	Elec. price index ($/MWh)
UnitC_1	1 – Startable	$1,000	1,500	$12.00	0.0530752	$10,000	200	60	$0.38	20	$1.00
UnitC_2	2 – NOT startable	$2,000	2,300	$12.00	0.0530752	$20,000	250	60	$0.38	20	$1.00
UnitC_3	3 – Startable	$3,000	3,400	$12.00	0.0530752	$35,000	400	60	$0.38	20	$1.00
UnitC_4	4 – NOT startable	$4,000	4,400	$12.00	0.0530752	$42,000	450	60	$0.38	20	$1.00

Table H11 assumes that the CAISO has enough information from the Scheduling Coordinator to calculate each Proxy Start-Up and indirect Proxy 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 be provided but is instead copied from the next lowest configuration. As discussed in greater detail later, not providing Resource Data Template values for the parameters used in Proxy Start-Up Costs or Proxy Transition Costs for certain Start-Up or indirect Start-Up Costs may result in a lower or zero Transition Cost.

Table H12
Proxy Start-Up and indirect Proxy Start-Uup Cost calculation for missing data: non-natural gas-fired turbine-based and thermal

Config ID	Configuration	Non-nat gas start cost ($)	Heat input (MMBtu)	GHG price	GHG emission rate	Major maint. adder	Config Pmin	Config startup time	GMC	Start-Up energy (MWh)	Elec. price index ($/MWh)
UnitC_1	1 – Startable	$1,000	1,500	$12.00	0.0530752	$10,000	200	60	$0.38	20	$1.00
UnitC_2	2 – NOT startable	$1,000	1,500	$12.00	0.0530752	$10,000	200	60	$0.38	20	$1.00
UnitC_3	3 – Startable	$3,000	3,400	$12.00	0.0530752	$35,000	400	60	$0.38	20	$1.00
UnitC_4	4 – NOT startable	$3,000	3,400	$12.00	0.0530752	$35,000	400	60	$0.38	20	$1.00

Step 2: CAISO uses submitted data to calculate Transition Costs

Table H13 reproduces the same inputs as Table H11. The last column in blue calculates the Proxy Start-Up or indirect Proxy Start-Up Cost:

Proxy Start-Up Cost = (Non-natural gas Start-Up Cost) + (Start-Up Energy x Energy Price Index) + (Pmin x Start-Up Time Period in min / 60 min/hour x GMC adder / 2) + (Heat Input x GHG Emission Rate x GHG Allowance Price) + Major maintenance adder

Table H13
Proxy Start-Up Cost calculation: non-natural gas-fired, turbine-based and thermal

Config ID	Configuration	Non-nat gas start cost ($)	Heat input (MMBtu)	GHG price	GHG emission rate	Major maint. Adder	Config Pmin	Config startup time	GMC	Start-Up energy (MWh)	Elec. price index ($/MWh)	Cost
UnitC_1	1 – Startable	$1,000	1,500	$12.00	0.0530752	$10,000	200	60	$0.38	20	$1.00	$12,104
UnitC_2	2 – NOT startable	$2,000	2,300	$12.00	0.0530752	$20,000	250	60	$0.38	20	$1.00	$23,533
UnitC_3	3 – Startable	$3,000	3,400	$12.00	0.0530752	$35,000	400	60	$0.38	20	$1.00	$40,262
UnitC_4	4 – NOT startable	$4,000	4,400	$12.00	0.0530752	$42,000	450	60	$0.38	20	$1.00	$48,908

If the resource is non-thermal, the only difference is the elimination of the greenhouse gas cost calculation. The formula would be the same for a non-natural gas thermal resource without a greenhouse gas obligation.

Proxy Start-Up Cost = (Non-natural gas Start-Up Cost) + (Start-Up Energy x Energy Price Index) + (Pmin x Start-Up Time Period in min / 60 min/hour x GMC adder / 2) + Major maintenance adder

At this time the ISO cannot directly reflect multiple fuels for the same resource.

Table H14 shows the Proxy Transition Costs based on the Start-Up and indirect Proxy Start-Up Costs shown in Table H13. The Proxy Transition Costs are equal to 100 percent of Transition Costs (i.e. no headroom scalar applied). All of the Transition Costs are calculated as the difference between the "To" configuration and "From" configuration Proxy Start-Uup and indirect Proxy 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 Proxy Start-Up Cost for configuration 1. After it transitions, it would only incrementally incur the Proxy 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
Proxy Transition Cost calculation: non-natural gas-fired, turbine-based and thermal

		"To" configuration			
		UnitC_1	UnitC_2	UnitC_3	UnitC_4
"From" configuration	UnitC_1		$11,429	$28,158	$36,804
	UnitC_2			$28,158	n/a
	UnitC_3				$8,646
	UnitC_4				

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 Resource Data Template values for the parameters used in Proxy Start-Up Costs or Proxy Transition Costs 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 H15
Proxy Transition Cost calculation for missing data: non-natural gas-fired, turbine-based and thermal

		"To" configuration			
		UnitA_1	UnitA_2	UnitA-3	UnitA_4
"From" configuration	UnitA_1		$0	$28,158	$28,158
	UnitA_2			$28,158	n/a
	UnitA_3				$0
	UnitA_4				

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 must register Transition Costs of up to 150 percent of Proxy Transition Costs. Scheduling Coordinators under the Proxy Cost option can bid daily up to 125 percent of the calculated transition cost plus a transition cost opportunity cost if applicable. A scheduling coordinator may not change its election of Registered Cost or 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 Resources Providing RA Capacity~~BIDDING ENFORCEMENT RULES FOR NON-RESOURCE SPECIFIC SYSTEM RESOURCES WITH RESOURCE ADEQUACY OBLIGATIONS~~

~~J~~Please refer to section 7.1.1 in the Reliability Requirements BPM.

~~. 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:~~

~~min(RA, (IFM schedule + any incremental RUC schedule))~~

~~The minimum of these two values is used because:~~

~~When the IFM + incremental RUC is greater than the RA obligation, the Real-Time requirement is limited to the RA obligation.~~

~~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:

- Intercontinental Exchange (ICE) End of Day Report
- ARGUS Air Daily.

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 is an index calculated daily.
  The CAISO uses prices for the current year vintage greenhouse gas allowances.
- If the price index lists greenhouse gas allowance prices based on futures or forwards prices, the CAISO uses the price corresponding to a December delivery date.
- If the price index lists a range of prices, then the CAISO uses the volume-weighted average price if available, alternatively, it uses the simple average price.
- If a vendor greenhouse gas price is unavailable for any reason by 22:00, the CAISO will use the most recent available greenhouse gas price from that vendor corresponding to a December delivery date.
- The CAISO will average two vendor greenhouse gas prices to produce a greenhouse gas price index.
- If both vendor greenhouse gas prices are unavailable for any reason by 22:00, the CAISO will use the most recent Greenhouse Gas Allowance Price based on two or more source prices.
- The Greenhouse Gas Allowance Price will be posted after 22:00 based on source prices representing trades 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 when both vendor prices are available.
- 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 downloaded from OASIS by selecting the date January 23, 2013. That price in OASIS will have been published between 19:00 and 22:00 on January 22.

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:

Average CO_2e emissions at minimum load ($mtCO_2e/MWh$) * 1 (allowance/$mtCO_2e$) * Greenhouse Gas Allowance Price ($/start-up)

Where:

Average CO_2e emissions at minimum load ($mtCO_2e/MWh$) = unit's average heat rate at minimum load (mmBTU/MWh) * CO_2e emission rate ($mtCO_2e/mmBTU$).

Both the average heat rate and 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. Multiply this cost by the resource Pmin 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:

   Incremental CO_2e emissions ($mtCO_2e/MWh$) * 1 (allowance/$mtCO_2e$) * Greenhouse Gas Allowance Price ($/allowance)

   Where:

   Incremental CO_2e emissions ($mtCO_2e/MWh$) = unit's incremental heat rate (mmBTU/MWh) * CO_2e 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_2e emission rate is submitted by the SC in the Master File. The CO_2e 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:

Startup fuel requirement:	1,083 mmBTU/start-up
CO_2e emission rate:	0.053165 $mtCO_2e$/mmBTU
Greenhouse Gas Allowance Price :	$15.70 /allowance

CO_2e emissions per startup = start-up fuel requirement * CO_2e emission rate = 1083 * 0.053165 = 57.57769 $mtCO_2e$/start-up.

Greenhouse gas allowance start-up cost = CO_2e 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:

Average heat rate at minimum load:	7.840 mmBTU/MWh
Resource Pmin	160 MW
CO_2e emission rate:	0.053165 $mtCO_2e$/mmBTU
Greenhouse Gas Allowance Price :	$15.70 /allowance

Average CO_2e emissions at minimum load = unit's average heat rate at minimum load * CO_2e emission rate = 7.840 * 0.053165 = 0.41681 $mtCO_2e$/MWh.

Greenhouse gas allowance minimum load cost = Average CO_2e emissions at minimum load * 1 * Greenhouse Gas Allowance Price = 0.41681 * 1 * $15.70 = $6.54 /mWH.

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:

Operating Point (n)	Operating Level (MW)	Segment	Adjusted Incremental Heat Rate (BTU/kWh)
1	164	1	7292
2	298	2	7643
3	340	3	5438
4	480	4	9601
5	590		

And let's use the same GHG data from previous examples:

CO_2e emission rate:	0.053165 $mtCO_2e$/mmBTU
Greenhouse Gas Allowance Price :	$15.70 /allowance

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 CO_2e emissions = unit's incremental heat rate * CO_2e emission rate = 7292 * 0.053165 / 1000 = 0.38768 $mtCO_2e$/MWh.

Greenhouse gas allowance incremental energy cost = Incremental CO_2e 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:

Segment	Operating Range	Adjusted Incremental Heat Rate	GHG Incremental Cost	GHG Cost After Left-to-Right Adj
1	164-297	7292	$6.09	$6.09
2	298-339	7643	$6.38	$6.38
3	340-479	5438	$4.54	$6.38
4	480-589	9601	$8.01	$8.01

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.

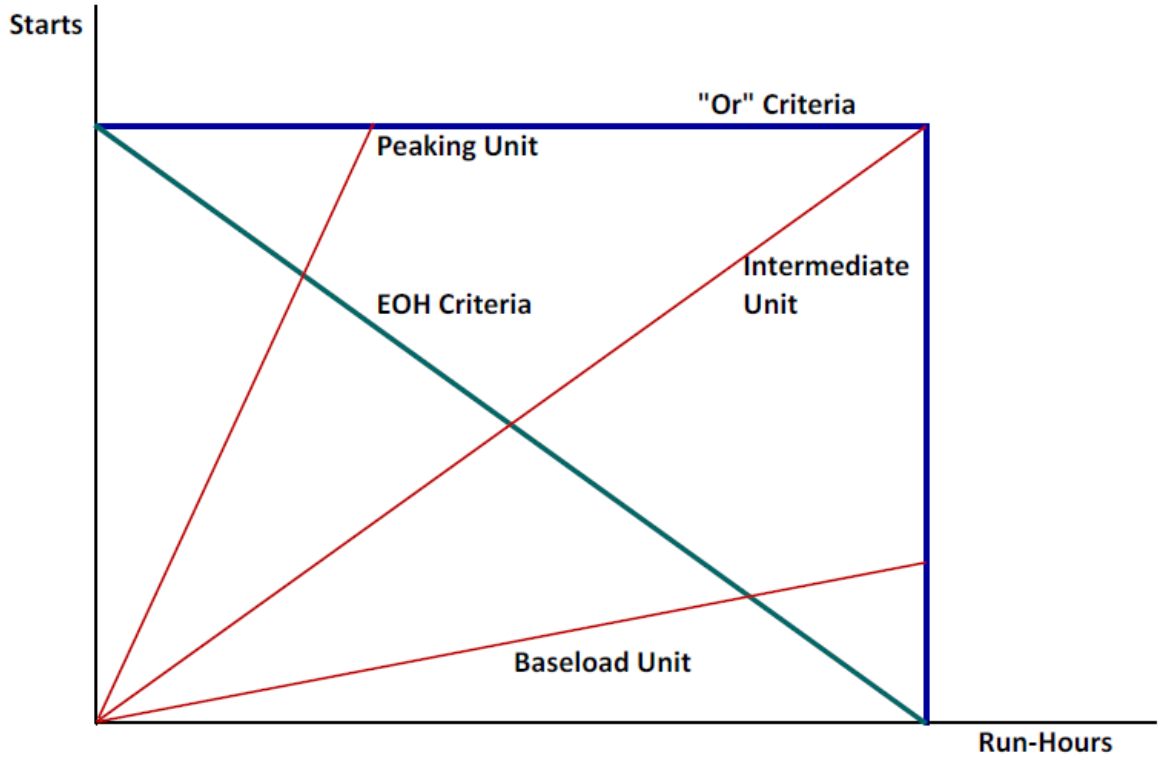
The template is located at:

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 an electricity price. This component is calculated for all generating resources.[42] 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.

M.2 Retail Region Price

A resource that pays a retail electricity price for its auxiliary power can submit a request to establish a retail electric region. The current list of approved electric regions for CAISO and EIM entities is located here: [http://www.caiso.com/market/Pages/NetworkandResourceModeling/Default.aspx]. The electricity price for each retail provider is updated semi-monthly, on the 5th business day and the 5th last business day of each month. For example, in the month of August, the retail rates are checked on the 5th and the 26th of August.

The seasonal applicability of the retail price is determined based on definition in the stand-by service schedule for each region. For example, the Southern California Edison Standby Service Rate is sourced from Schedule TOU-8 RBY time of use general service large reliability back up service metered and delivered above 50 kV Generation UG. Summer is defined as June 1 – September 30, and winter is defined as October 1 – May 31. The peak hour retail price is used by the CAISO for any day with a peak hour and the off-peak hour retail price is used on weekends and holidays.

M.2.1 Establish a Retail Electric Region

A Scheduling Coordinator can submit a request to establish a new retail electric region for use in the EPI. The following items are required:

- Service schedule from a retail electricity service provider. Include links and the specific schedule.

Requests for a new electric region can be submitted using the CIDI system. The timeline for the establishment of a new electric region will depend on the availability of the components

[42] 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.

submitted. The CAISO will contact the Scheduling Coordinator if additional information in needed to establish the retail electric region.

M.2.2 Assign a resource to a Retail Electric Region

Scheduling Coordinators for resources that pay a retail rate for auxiliary power can submit a request via the CIDI system to have the resource associated with a retail electric region. The Scheduling Coordinator must submit an invoice from a retail electricity service provider for electric service for the specific resource or other documentation reasonably acceptable to the CAISO demonstrating that the resource is being charged the proposed retail electric service rate. The CAISO will validate the submittal and change the electric region in the Master File for the resource if the invoice or other documentation supports the retail electric region change.

M.3 Wholesale Region Price

Each resource will default to a wholesale electric region unless a request for a retail electric region is approved. A wholesale electric region will be created corresponding to every gas fuel region. The wholesale EPI will be calculated using a projected monthly gas price. The forward monthly gas price is the average of the closing gas prices for the gas delivery points for the trading days that existed through the X^{th} day of the current calendar month, for delivery in the next calendar month. The value of 'X' is usually 2 days before the end of the month.

The formula for the wholesale electricity price index for a resource is:

Wholesale EPI = (Forward Monthly Gas Price + Total Transportation Cost + Miscellaneous Tax-based Cost + Miscellaneous Non Tax-based Cost) *10

Example of EPI calculation

The following example includes detailed steps for calculating the electricity price index using the forward monthly gas price for the PG&E Citygate gas delivery point. 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 M are the average of the values in column H. Taking the average of the futures prices for PG&E CityGate through the 28th, we get a value of $5.16.

   If the transportation cost = $1.1 and the miscellaneous cost = 0, the EPI of the wholesale electric region = ($5.16+$1.1+$0)*10 =$62.6 for the month of April 2012

Figure 1: 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.

A	B	E	F	H	L	M	O	P	C
Closing Date	Trade Month	Henry Hub Price	Basis Swap at PG&E CityGate	Gas Delivery Price at PG&E CityGate		Avg PG&E (month-to-date)			
3/1/2012	Apr-12	$4.18	$0.66	$4.84		4.84			
3/2/2012	Apr-12	$4.17	$0.44	$4.61		4.73			
3/5/2012	Apr-12	$4.55	$0.51	$5.06		4.84			
3/6/2012	Apr-12	$4.92	$0.49	$5.41		4.98			
3/7/2012	Apr-12	$4.66	$0.42	$5.08		5.00			
3/8/2012	Apr-12	$4.98	$0.47	$5.45		5.08			
3/9/2012	Apr-12	$4.69	$0.65	$5.34		5.11			
3/12/2012	Apr-12	$4.71	$0.64	$5.35		5.14			
3/13/2012	Apr-12	$4.66	$0.56	$5.22		5.15			
3/14/2012	Apr-12	$4.61	$0.58	$5.19		5.16			
3/15/2012	Apr-12	$4.52	$0.65	$5.17		5.16			
3/16/2012	Apr-12	$4.25	$0.50	$4.75		5.12			
3/19/2012	Apr-12	$4.89	$0.68	$5.57		5.16			
3/20/2012	Apr-12	$4.86	$0.45	$5.31		5.17			
3/21/2012	Apr-12	$4.89	$0.65	$5.54		5.19			
3/22/2012	Apr-12	$4.64	$0.52	$5.16		5.19			
3/23/2012	Apr-12	$4.76	$0.56	$5.32		5.20			
3/26/2012	Apr-12	$4.08	$0.65	$4.73		5.17			
3/27/2012	Apr-12	$4.15	$0.65	$4.80		5.15			
3/28/2012	Apr-12	$4.66	$0.63	$5.29		5.16			
3/29/2012	Apr-12	$4.26	$0.69	$4.95		5.15			
3/30/2012	Apr-12	$4.17	$0.67	$4.84		5.14			

Attachment N

Opportunity Cost Calculation for Use-Limited Resources

N Opportunity Cost Calculation for Use-Limited Resources

Pursuant to Section 30.4.1.1.6 and Appendix A of the CAISO Tariff, a Use-Limited Resource is defined as a resource that meets all three of the following conditions:

- Has one or more limitation affecting its number of starts, run-hours, or energy output due to design considerations, environmental restrictions on operations, or qualifying contractual limitations.[43]

- Cannot reflect the limitation within the market optimization horizon (e.g., monthly limitations that extend beyond the day-ahead market 24-hour horizon).

- Can select hours of operation, and is not dependent on an energy source outside of the resource's control.

The inclusion of an opportunity cost adder to the commitment costs or the default energy bid (DEB) is intended to ensure a more efficient participation of Use-Limited Resources in the CAISO market. The CAISO will perform opportunity cost calculations on a monthly basis. If for any reason the CAISO cannot perform the opportunity cost calculation for a resource for the upcoming month, the CAISO will perform its processes subject to schedule in Section N.3.

N.1 Eligibility for Opportunity Cost Adder

The Use-Limited Resource designation in the Master File (MF) allows the Scheduling Coordinator (SC) to be eligible to establish an opportunity cost adder to its start-up, transition, and/or minimum load commitment cost bid caps under the proxy cost option[44] and/or to its default energy bid under the variable cost option, with the exception of resources with use limitations that have a daily granularity. The calculated or negotiated opportunity cost adder methodology will be filed at FERC when initially established. Resources under the negotiated rate option for the default energy bid filed prior to April 1, 2019 are not eligible for opportunity cost adders for any component of the three-part bid.

[43] Qualifying contractual limitations will only be accepted as an eligible use limitation until May 2022 as a transitional measure.

[44] Commitment cost bid caps include the start-up bid cap, transition bid cap, and minimum load bid cap, as a function of which use-limit type is associated with the resource.

If the resource and its limitations can be modeled as an energy output, start, or run-hour limitation applicable on a monthly, annual, or rolling-12 month period, the opportunity cost adder will be determined by modeling the market commitment of the resource based on projected LMPs. Section N.2 below has details of the opportunity cost model. Use-Limited Resources with limitations that cannot be modeled utilizing the method described below will be considered for a negotiated opportunity cost adder pursuant to Section N.4 below.

N.2 Methodology for Calculated-Based Opportunity Cost Adders

The opportunity cost model will be able to model limitations on the number of starts, run-hours, and/or energy output in MWh. Limitations may be applicable for a month, year, or rolling-12 month period. A resource with more than one limitation type which can be modeled will have a calculated opportunity cost for each limitation type. Each modeled limitation has two components that will be submitted in the Use Limit Plan Data Template (ULPDT):

Limitation type: This refers to the operating component which is limited as registered in the ULPDT as the use limit type, i.e., starts, run-hours, or energy output.

- **Start-up limitation:** The calculated opportunity cost for a limitation on the number of start-ups will be determined by the estimated profits foregone if the resource had one less start in the relevant time period. This will be a $/start-up value.
- **Run-hour limitation:** The calculated opportunity cost for a limitation on the number of run-hours will be determined by the estimated profits foregone if the resource had one less run-hour in the relevant time period. This will be a $/hour value.
- **Energy/Output limitation:** The calculated opportunity cost for a limitation on the energy output of the resource will be determined by the estimated profits foregone if the resource had one less MWh to generate in the relevant time period. This will be a $/MWh value added to every segment of the default energy bid calculated under the variable cost option. Opportunity cost will not be added to the negotiated rate option or locational marginal price option for the default energy bid.

Applicability: This refers to the timeframe for which the limitation is applied as registered in the ULPDT as the granularity, i.e., monthly, annual, or rolling 12-month.

Table N.1 below provides an overview of the major components needed to calculate the opportunity cost adder, including the inputs, calculation procedures, outputs, and the usage of the outputs. As an input, the optimization model will rely on validated limitations registered in the ULPDT, Master File characteristics registered in the Generator Resource Data Template (GRDT), and pre-calculations for estimated costs for start-up, minimum load and energy, and forecasted LMPs. The details of the calculation of estimated costs and forecasted LMPs are

provided in Section N.2.1 below. These inputs are used in a unit commitment optimization model to determine resource-specific opportunity cost adders for each registered limitation type of the resource. This cost is based on calculating the profit (or gross margin) that is foregone if one less start, one less operating hour, and/or one less MWh is available, as applicable. Lastly, the opportunity cost adder will be reflected in commitment cost bid caps under the proxy cost option or added to the resource's variable cost option for the default energy bid.

The opportunity cost calculator will be run on a monthly basis, in the month prior to the time period for which the resource limitations are applicable[45]. An opportunity cost will be calculated for each validated limitation that can be modeled.

Table N.1 Overview of Opportunity Cost Methodology

Model Input Submitted Values	Model Input Pre-Calculations	Opportunity Cost Calculation	Model Output
• Use limitations (ULPDT) • Resource characteristics (GRDT) • Actual market starts, run-hours, or energy output values incurred within the limitation period to account for remaining limitation availability. The actual limitations are counted as of the time the monthly process is started. See Section N.3 for the Schedule for the monthly run. For example, if a resource has a registered limitation of 300 starts per year and has incurred 100 market starts in the months of January-April, the OC calculation for the	• Estimated costs for start-up, transition (if applicable), minimum load, and energy calculated using MF parameters, future gas prices, and greenhouse gas (GHG) prices at resource's pricing node (PNode) or aggregated PNode • Resource's PNode or aggregated PNode forecasted LMPs calculated using historical LMPs and gas prices and a power price conversion factor based on future power prices.	Unit commitment model that maximizes resource's profit over the validated limitation period (e.g., monthly) based on defined inputs and the reserve margin factor. This profit maximization model is run for the base case with the limitation applied versus a run with one less use limitation available (i.e., foregone profits of one less use).	Resource-specific opportunity cost adders for start-up, transition, minimum load, and energy, as applicable. The adders will be reflected in commitment cost bid cap(s) under proxy cost options or as an adder to resource's DEB under variable cost option.

[45] If for any reason the CAISO cannot perform the opportunity cost calculation for a resource for the upcoming month, the CAISO will perform its processes subject to schedule in Section N.3.

months of May-December will consider the available limitation as 300 starts minus 100 starts = 200 **starts.**			

N.2.1 Model Input for Opportunity Cost Calculation

As an input, the optimization model will rely on limitations provided to the CAISO through the Use-Limited Resource registration process in the ULPDT, Master File characteristics registered in the GRDT, and pre-calculations for estimated costs for start-up, minimum load and energy, and forecasted LMPs. Each of these is discussed in more detail below.

N.2.1.1 Resource Characteristics and Limitations

The CAISO will rely on templates submitted to the ULPDT to determine the resource's validated limitation(s). The CAISO will also use Master File characteristics of the resource such as its minimum generation capacity (i.e., minimum load),[46] maximum generation capacity (i.e., maximum load),[47] minimum up time,[48] and minimum down time.[49]. For a Multi-Stage Generating resource with a limitation on the number of starts, the implied starts registered in the GRDT will be used as the basis to count the number of resource starts. The documentation provided during the use-limited registration process should support the limit on starts in the ULPDT as well as the implied starts in the GRDT.

N.2.1.2 Estimated Costs

The model requires as inputs estimates of the monthly variable energy cost, minimum load cost, and start-up cost of the resource. Transition cost is derived as the difference of the start-up costs of the "TO-configuration" and the start-up costs of the "FROM-configuration" for feasible transitions. The commitment cost estimates are based on the proxy cost formulas as described in Attachment G.2 of the Business Practice Manual (BPM) for Market Instruments[50] with adjustments necessary to forecast the costs for future months. The variable energy cost calculation will be megawatt-weighted and the cost based on the DEB formulation, or equivalent, as described in Attachment D of the BPM for Market Instruments.

In order to determine these future estimated costs for gas resources, a monthly futures gas price index is used. Depending on the specific fuel region, a future gas price index can be used

[46] Generator Resource Data Template field MIN_GEN.

[47] Generator Resource Data Template field MAX_GEN.

[48] Generator Resource Data Template field MIN_ON.

[49] Generator Resource Data Template field MIN_OFF.

[50] Refer to Attachment G.2 for proxy cost formulas at https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Market Instruments.

from different providers such as ICE, Platts, SNL and NGI. The transportation cost will be calculated using the transportation cost configuration parameters that include fuel reimbursement rate, marginal transportation rate, cap-and-trade credits, and miscellaneous transportation costs in effect at the time of calculation. For resources with greenhouse gas obligations, the most recent daily greenhouse gas price available at the time of calculation will be used. These details will be documented in the opportunity cost filings made at FERC.

N.2.1.3 Forecasted LMP

The CAISO will generate hourly real-time prices for future months by calculating an hourly implied marginal heat rate at each Use-Limited Resource's PNode or aggregated PNode based on fifteen-minute real-time energy prices from the same hour the previous year.

The LMPs will be estimated by executing the following equations in the order shown below:

(1) For each future hour, calculate an hourly implied heat rate at each applicable PNode or aggregated PNode for a Use-Limited Resource based on the hourly average of the fifteen-minute real-time LMPs from the same hour the previous year, the greenhouse gas allowance price from the same day of the previous year, and the gas price index of the applicable fuel region from the same day of the previous year.

$$ImpHR_{k,y-1} = \frac{LMP_{k,y-1}}{GPI_{k,y-1} + (GHGas_{k,y-1} * EmRate)}$$

Where:

$LMP_{k,y-1}$ is the hourly average of the fifteen-minute real time energy price at PNode or aggregated PNode of resource (k) from the same hour of the previous year (y-1)

$GHGas_{y-1}$ is the daily greenhouse gas allowance price from the same day of the previous year (y-1)

EmRate is the greenhouse gas content of natural gas, which is .0531148mtCO2e/MMBtu6

$GPI_{k,y-1}$ is the daily gas price index of the fuel region of resource k from the same day of the previous year, y-1

(2) For each future month, calculate a monthly future implied heat rate based on the applicable wholesale future power price of the applicable power-trading hub, the most recent greenhouse gas allowance price, and the natural gas future commodity price of the applicable fuel region.

$$ImpHRF_{k,m} = \frac{PPF_{k,H,m}}{NatGasF_{k,m} + (GHGas_{m-1} * EmRate)}$$

Where:

$PPF_{k,H,m}$ is the ICE future peak power price at power price hub (H) of resource (k) for future month (m) based on mapping each resource to a power trading hub based on the power price hub location. The mapping is found in the GRDT in the POWER_PRICE_HUB field.

$NatGasF_{k,m}$ is the natural gas futures price of the fuel region of resource (k) for month (m)[51]

$GHGas_{m-1}$ is the average greenhouse gas allowance price from the previous month (m-1)

EmRate is the greenhouse gas emissions rate per MMBtu of natural gas, which is *.0531148mtCO2e/MMBtu*

(3) For each future month, calculate a monthly historical implied heat rate based on the wholesale historic power price of the applicable power trading hub for the same month in the previous year, the average greenhouse gas allowance price for the same month in the previous year, and the average natural gas commodity price of the applicable fuel region for the same month in the previous year.

$$ImpHRH_{k,m-12,} = \frac{PPH_{k,H,m-12}}{NatGas_{k,m-12} + (GHGas_{m-12} * EmRate)}$$

Where:

$PPH_{k,H,m-12}$ is the ICE future peak power price at the power price hub (H) of resource (k) from the same month of the previous year (m-12) based on mapping each resource to a power trading hub based on the power price hub location. The mapping is found in the GRDT in the POWER_PRICE_HUB field.

$NatGas_{k,m-12}$ is the monthly average of daily natural gas price indices inclusive of transportation costs from the fuel region of resource (k) from the same month of the previous year (m-12)

$GHGas_{m-12}$ is the monthly average greenhouse gas allowance price from the same month of the previous year (m-12)

EmRate is the greenhouse gas content of natural gas, which is $.0531148 mtCO2e/MMBtu$

(4) For each future month, calculate a monthly power price conversion factor as the ratio of the future implied heat rate calculated in (2) and the historical implied heat rate calculated in (3)

$$PPConv_{k,m} = \frac{ImpHRF_{k,m}}{ImpHRH_{k,m-12}}$$

[51] The CAISO determines the natural gas futures commodity price by fuel region averaging available prices from the following vendors: Intercontinental Exchange, Natural Gas Intelligence, and SNL Energy/BTU's Daily Gas Wire.

(5) For each future hour, scale the hourly implied marginal heat rate calculated under equation (1) by the power price conversion factor calculated under equation (4).

(6) For each future hour, calculate the LMPs by applying the gas price index of the future month and the most recent greenhouse gas costs to the scaled implied heat rates calculated under equation (5).

$$LMP_{k,h} = ImpHR_{k,y-1} * PPConv_{k,m} * \left(GPIF_{k,m} + (GHGas_{m-1} * EmRate)\right)$$

Where:

$LMP_{k,h}$	is the estimated hourly real time price at resource's PNode (p) or aggregated PNode (A) represented as resource (k) for hour (h)
$ImpHR_{k,y-1}$	is the calculated hourly implied heat rate at the resource PNode or aggregated PNode
$PPConv_{k,m}$	is the calculated monthly power price conversion factor for each future month
$GPIF_{k,m}$	is the Gas Price Index for the future month (m) for fuel region of resource (k)
$GHGas_{m-1}$	is the average greenhouse gas allowance price from the previous month (m-1)
$EmRate$	is the greenhouse gas content of natural gas, which is $.0531148 mtCO2e/MMBtu$

The result is a set of resource-specific estimated hourly real-time energy prices at the resource's PNode or aggregated PNode. These estimated prices will be used in the opportunity cost model, along with the estimated resource costs and characteristics to estimate the dispatch of the resource over the study time period.

N.2.2 Opportunity Cost Calculation

N.2.2.1 Optimization Model

The opportunity cost is the estimated profits foregone if the resource has one less start, one less run-hour, and/or one less MWh to generate. The foregone profit, or opportunity cost, is calculated as the difference between estimated profits of a "base" model run with all limitations enforced and the estimated profits from the case with a "limit" model run with the remaining limitation reduced by one

A reserve margin of 90% will apply to all limitations. For example, if a resource has an annual limitation of 300 starts, the opportunity cost will be the non-negative difference in estimated profits of the following two model runs:

Base model run: Optimization model run with start limitation set to 270 per year (90% of 300)

Limit model run: Run the model with one less start, i.e., 269 starts per year

The resource profit is calculated using an optimization model which will estimate a resource's hourly dispatch, over a given study period, using estimated resource specific costs and characteristics against the forecasted hourly LMPs. The objective cost of the optimization model is to maximize the profit over the study period, where the profit is calculated as the difference in revenue and costs. The formulation of the profit maximizing objective cost function based on hourly prices is as follows:

$$Max\ \pi_w = \sum_{h=1}^{n}\left\{\sum_{k=1}^{b}\langle\left(Online_{h,k} * \left[\left(LMP_{k,h} * MWh_{k,h}\right) - \left(VEC_{k,m} * \left(MWh_{k,h} - Pmin_k\right)\right) - MLC_{k,m}\right]\right) - \left(Starting_{k,h} * SUC_{m,g,k}\right)\rangle - \sum_{p=1}^{c}\langle Transitioning_{h,p} * TC_{m,p}\rangle\right\}$$

Where:

h	denotes hours within the analysis time horizon
n	is the number of hours in the analysis time horizon
w	denotes plant for multi-stage generating (MSG) resources or same as (k) for non-MSG resources, (k) denotes non-MSG resource or non-MSG configuration
b	is the number of MSG configurations for MSG resources ; 1 for non-MSG resources.
t	denotes MSG transition
c	is the number of MSG transitions for MSG resources ; 0 for non-MSG resources.
k	denotes PNode at non-MSG resource or non-MSG configuration (k)
$Online_{k,h}$	is the optimal commitment (0/1) flag to indicate if resource or MSG configuration (k) is online (1) (active) or offline (0) at hour (h)
$Starting_{k,h}$	is the 0/1 flag to indicate if resource or active MSG configuration (k) and optimal segment (g) is starting (1) at hour (h); otherwise (0)
$Transitioning_{t,h}$	is the 0/1 flag to indicate if active MSG transition (t) has occurred at hour (h) (1); otherwise (0)

$LMP_{k,h}$ is the estimated hourly LMP, for hour (h), at the resource's PNode (p) or aggregated PNode (A) or MSG configuration (Y) represented as (k)

$MWh_{k,h}$ is the optimal dispatch of the of the resource's PNode (p) or aggregated PNode (A) or MSG configuration (Y) represented as (k) during hour (h)[52]

$VEC_{k,m}$ is the estimated variable energy cost of the resource's PNode (p) or aggregated PNode (A) or MSG configuration (Y) represented as (k)

$MLC_{k,m}$ is the estimated minimum load cost of the resource's PNode (p) or aggregated PNode (A) or MSG configuration (Y) represented as (k)

$SUC_{k,g,m}$ is the estimated start-up cost of the resource's PNode (p) or aggregated PNode (A) or MSG configuration (k) for the optimal start segment (g)

$TC_{t,m}$ is the estimated transition cost of the MSG resource for transition (p)

Subject to:

C1) *MIN_GEN* <= *MWh* <= *MAX_GEN*, if committed

C2) *Count(h, where resource is online during consecutive hours) >= MIN_ON*

C3) *Count(h, where resource is offline during consecutive hours) >= MIN_OFF*

Additional constraints for modeled limitations

If the resource, MSG plant (w), or MSG configuration (Y) represented as resource (k) has a limitation on starts,

C4) *SUM* ($Startups_k$) <= $Start_Limit_k$ over the limitation granularity horizon[53]

For the base model run:

$Start_Limit_k = x * (MaxSTRT_k - ActSTRT_k)$

Where,

x is the reserve margin (90% or 0.9)

[52] The model uses a single variable energy cost estimate, therefore the MWh value will either be 0, minimum operating point, or maximum operating point.

[53] If the resource, MSG plant (w), or MSG configuration (Y) represented as resource k has more than one limitation for a given use limit type, the optimization granularity horizon will apply based on the longest granularity. For example, if resource (k) has a start limitation on a monthly granularity and a start limitation on annual granularity, the limitation granularity horizon will be 12 months.

$MaxSTRT_k$ is the maximum permissible implied starts registered in the ULPTD in the limitation field applicable for the limitation granularity horizon

$ActSTRT_k$ is the actual implied starts already incurred in the limitation granularity horizon

For the limit model run:

$Start_Limit_k = [x * (MaxSTRT_k – ActSTRT_k)] - 1$

If the resource has a limitation on run-hours,

C5) *Count (h, where the resource is online in the limitation horizon) <= Runhour_Limitk* over the limitation granularity horizon

For the base model run:

$Runhour_Limit_k = x * (MaxHRS_k – ActHRS_k)$

Where,

X is the reserve margin (90% or 0.9)

$MaxHRS_k$ is the max permissible run-hours registered in the ULPTD in the limitation field applicable for the limitation granularity horizon

$ActHRS_k$ is the actual run-hours already incurred in the limitation granularity horizon

For the limit model run:

$Runhour_Limitk = [x * (MaxHRS_k – ActHRS_k)] - 1$

If the resource has a limitation on energy output,

C6) *Sum*(MWh_h) <= $Energy_Limit_k$ over the limitation granularity horizon

For the base model run:

$Energy_Limit_k = x * (MaxMWH_k – ActMWH_k)$

Where,

x is the reserve margin (90% or 0.9)

$MaxMWH_k$ is the maximum permissible MWh output registered in the ULPTD in the limitation field applicable for the limitation granularity horizon

$ActMWH_k$ is the sum of actual energy output already incurred in the limitation granularity horizon

For the limit model run:

$Energy_Limit_k = [x * (MaxMWH_k – ActMWH_k)] -1$

The last three constraints (C4-C6) represent the limitations for which an opportunity cost needs to be calculated. These can be enforced together for a resource with more than one limitation type applicable on the same limitation granularity. For example, if a resource has a monthly limitation of 30 starts per month, and a monthly limitation of 20 run-hours per month, and based on the 90% reserve margin the model runs will be as follows:

Base model run with starts limited to 27 (90% of 30) and run-hours limited to 18 (90% of 20)

Start limit model run with starts limited to 26 and run-hours limited to 18

Run-hour limit model run with starts limited to 27 and run-hours limited to 17

The start-up opportunity cost is calculated as the non-negative difference of the monthly profit from the base model run and the profit from the start limit model run. The run-hour opportunity cost is calculated as the non-negative difference of the monthly profit from the base model run and the profit from the run-hour limit model run.

N.2.2.2 Nested Limitation

A resource may have more than one limitation of the same type, i.e., limitation on starts applicable on different granularities (monthly and annually). The estimated opportunity costs due to these two limitations are simultaneously enforced so the optimization can maximize the resource's profits across the limitation granularity horizon[54] to produce an opportunity cost adder that combines the impact of enforcing the limitations into one value. The opportunity cost adder can then be reflected in the bid cap of the applicable commitment cost bid cap under the proxy cost option or the DEB under the variable cost option. For example, if a resource has a monthly limitation on starts of 20, and an annual limitation on starts of 140, and the reserve margin is 90%, the opportunity cost for each month will be calculated using the annual profits from the following two runs:

Base model run: Limit the annual starts to 126 (0.9*140), and the monthly starts to 18 (0.9*20)

Limit model run: Limit annual starts to 125 and limit the month for which an opportunity cost is being calculated to 17; the remaining months are still limited to 18 starts

[54] The limitation granularity horizon for nested limitations will be set at the granularity with the longest time horizon. If the resource has a nested monthly start limit and annual start limit, the limitation granularity horizon will be the balance of the annual period. The same logic will apply for nested limitations of different use limit types.

N.2.2.3 Opportunity Cost Calculation for MSG Resource

MSG resources may be use-limited if they meet the criteria set forth in Section 30.4.1.1.6.1.1 of the CAISO Tariff and complete the Use-Limited Resource registration process.[55] Some limitations on MSG resources apply to the resource in its entirety, i.e., at the parent resource level or plant level, while others apply to the configurations and transitions between configurations. As part of the registration process, the CAISO will determine if an MSG resource can be modeled in the opportunity cost calculation or if it must instead be subject to the negotiated opportunity cost process.

Limitations that apply to the plant resource level will have one opportunity cost calculated for each limitation type that will be applied to the configurations. For example, an MSG resource with a parent resource level limitation on run-hours will have an opportunity cost calculated that will be reflected in the minimum load cost bid cap under the proxy cost option of every configuration. Similarly, an opportunity cost due to an energy limitation on the parent resource level will be added to the DEB under the variable cost option of each configuration. Limitations that apply to a given configuration will have an opportunity cost for each limitation, for that configuration[56]. For example, the opportunity cost due to a run-hour limitation on a given configuration will be reflected in the minimum load cost bid cap of that configuration.

In cases where a transition between configurations is considered a start to which the limitation applies, an opportunity cost will be calculated for each feasible transition as the start-up opportunity cost of the to-configuration. The transition cost bid cap under proxy cost option is calculated as follows:

$$TC_{From \rightarrow To} = [1.25 * (SUC_{To} - SUC_{From})] + SU_OC_{To}$$

Where:

$TC_{From->To}$	Transition cost bid cap for transition from from-configuration to to-configuration
SUC_{To}	Proxy start-up cost of to-configuration
SUC_{From}	Proxy start-up cost of from-configuration
SU_OC_{To}	Start-up opportunity cost of to-configuration

For MSG configuration starts and transitions, the start-up opportunity cost is calculated per implied start for each configuration. This value is multiplied by the number of implied starts registered in the GRDT, to derive the opportunity cost to be added to the start-up cost bid cap or

[55] To complete the process, the Scheduling Coordinator must submit a use-limited registration request, complete all internal processing, receive notification the CAISO will designate the resource as a Use-Limited Resource based on registering a qualifying limitation and CAISO will set the USE_LIMIT_FF to 'Y' in the GRDT, and submit the ULPDT via the Master File User Interface.

[56] SC should denote the limitation is on the configuration level by including the configuration ID value in the ULPDT. If the limitation is at the parent resource level, the configuration ID field should be blank.

transition cost bid cap, as applicable. See Section 2.1.15 of Business Practice Manual for Market Instruments for more detail on registering implied starts in the GRDT.

N.3 Schedule of Updating Opportunity Cost Adder

The opportunity cost of each limitation will be calculated in advance of the limitation granularity effective start time. The CAISO will make the opportunity cost adder and a summary of model results available to the Scheduling Coordinators via the CAISO Market Results Interface (CMRI) prior to the month for which the opportunity costs become effective. The CAISO will not start the model run prior to the 10th calendar day of the month prior to the trade month. If a resource has an update to the limitation values in the ULPDT, the update to the ULPDT must be submitted by the 5th calendar day in the month prior to the trade month to be considered in the opportunity cost calculation.If a resource has an update to the limitation values in the ULPDT, the update to the ULPDT must be submitted by the 5th calendar day in the month prior to the trade month to be considered in the opportunity cost calculation.

Additionally, a daily report will be published on CMRI with the opportunity cost adders used in each market (day-ahead and real-time) for each trade date. In the event that the opportunity cost adder is updated during a trade month, the update will only be visible on the daily report since the monthly report is published prior to the trade month.

In the event that the CAISO is unable to perform such calculations or updated calculations for all Use-Limited Resources, the CAISO will give priority to performing such calculations or updated calculations for those Use-Limited Resources that are currently on pace to reach their maximum allowed numbers of starts, maximum allowed numbers of run-hours, or maximum allowed energy output more quickly than the most recent calculations of opportunity costs indicated.

To the extent that the CAISO is unable to perform such calculations or updated calculations for a Use-Limited Resource, the CAISO will utilize the most recently calculated or updated opportunity costs that have been set or are advisory for the Use-Limited Resource, where the advisory prices are the previously calculated opportunity costs for the binding trade month.

N.4 Negotiated Opportunity Cost Calculation

Resources with complex limitations that cannot be modeled utilizing the method described in Section N.2 above will be contacted by the CAISO to pursue a negotiated opportunity cost adder. Under this option, the CAISO would use documentation provided by the market participant and its discretion to pursue establishing the negotiated opportunity cost.

N.4.1 Information Needed

In order to establish a negotiated opportunity cost adder for a Generating Unit, the Scheduling Coordinator for the Generating Unit must provide the CAISO with the following information:

1. The proposed negotiated opportunity cost adder to be used for the Generating Unit. The Scheduling Coordinator must identify whether the opportunity cost adder it is requesting is being requested as an adder to the start-up bid cap, minimum load bid cap, and/or energy bids (generated energy bid or default energy bid under the variable cost option)[57].

2. The applicability horizon of the limitation including impacted market(s) and time periods for which the proposed opportunity cost would be applicable (day-ahead market and real-time market; peak and off-peak hours; start and end dates).

3. A descriptive explanation and justification of the basis or need for the proposed opportunity cost and why the opportunity cost model cannot capture the resource's complex limitations, including numerical calculations, input variables, values used, values that will vary during applicability horizon, and methodology and supporting documentation for input values including the Generating Unit's operating costs (e.g., fuel costs, operation and maintenance costs) and opportunity costs. The descriptive explanation and the methodology description should include formulas, simulation models, or historical analyses.

5. If applicable, the Scheduling Coordinator may propose two alternative costs: (a) a preferred opportunity cost reflecting the Scheduling Coordinator's opportunity cost, and (b) a temporary opportunity cost that could be utilized on an expedited basis pending more detailed review, discussion and negotiation concerning the preferred opportunity cost for the Generating Unit.

6. The proposed frequency of updates to the negotiated opportunity cost adder values. The frequency of updates proposed should be a function of the approved methodology where more formulaic approaches will allow more frequent updates compared to less transparent approaches.

N.4.2 Review of Information Submitted to the CAISO

The CAISO will review the information and assess the cost and/or formulas proposed by Scheduling Coordinators. Additional information may be requested from the Scheduling Coordinator as necessary to assess the reasonableness of the proposed opportunity cost and other potential opportunity costs. To expedite this process, the Scheduling Coordinator shall make representatives available to explain and discuss the rationale and supporting documentation for the proposed opportunity cost with the CAISO. All information provided by a Scheduling Coordinator shall be subject to the confidentiality provisions of the CAISO Tariff. Negotiated opportunity cost requests and communications should be sent to NOC@caiso.com

[57] CAISO will not support negotiated opportunity cost adders that apply only to the transition cost bid cap. The Scheduling Coordinator must establish a negotiated start-up opportunity cost adder and the adder will be included in the transition cost bid cap.

N.4.3 Effective Date of a Negotiated Opportunity Cost

Any opportunity cost proposed in writing by the CAISO to a Scheduling Coordinator shall become effective on the first trade date of the next calendar month after acceptance by the Scheduling Coordinator is received by the CAISO.

Any negotiated opportunity cost value and methodology agreed upon by the CAISO and a Scheduling Coordinator as an opportunity cost adder to the variable cost option for the default energy bid or as an adder to the commitment cost bid caps shall be filed at FERC within the first seven (7) days of the next calendar month. The opportunity cost shall remain in effect unless:

1. The opportunity cost is modified by FERC;

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

3. The CAISO or Scheduling Coordinator provides written notification that the opportunity cost is no longer acceptable for use under the negotiated rate option.

The CAISO will file at FERC by the next calendar month following the first trade date for which the negotiated opportunity cost is no longer in effect in its market.

N.4.4 Applicable Opportunity Cost Pending Agreement of a Negotiated Opportunity Cost

Pending any agreement between the Scheduling Coordinator and the CAISO with respect to an opportunity cost to be used as an opportunity cost adder to the variable cost option for the default energy bid or as an adder to the commitment cost bid caps, the Resource's opportunity cost shall be based on either:

1. The opportunity cost calculated by the methodology described in Section N.2 above; or

2. A temporary opportunity cost proposed by the CAISO.

A temporary opportunity cost established by the CAISO would be applicable only in the event that the CAISO determines that market or operational conditions warrant establishing a temporary opportunity cost (or modifying an opportunity cost) pending any agreement or resolution of the opportunity cost proposed by the Scheduling Coordinator as an opportunity cost adder to the variable cost option for the default energy bid or as an adder to the commitment cost bid cap. The CAISO may also need to establish an opportunity cost under this option in the event that sufficient data is not available to calculate an opportunity cost under any of the other options for establishing an opportunity cost under the CAISO tariff.

N.4.5 Dispute Resolution

If the CAISO does not approve the SC's submitted Opportunity Cost methodology, the CAISO and SC enter into a period of good faith negotiations to establish an agreed upon value. The negotiation period will be a minimum of (60) days as described in CAISO Tariff Section 30.4.1.1.6.3. Following the 60 day period, the SC has the right to file at FERC to establish an Opportunity Cost adder or to continue negotiating with the CAISO.

N.4.6 Possible Scenarios Leading to Renegotiation of an Opportunity Cost Adder

Each approved opportunity cost adder to the variable cost option for the default energy bid, start-up bid cap, and/or minimum load bid cap will only be applicable to the specific resource or configuration (if the resource is an MSG resource) that is active in the Master File and an associated Scheduling Coordinator who negotiated the opportunity cost with the CAISO. A negotiated opportunity cost will be reviewed and potentially renegotiated or terminated under the following non-exhaustive list of circumstances:

5. Change in Scheduling Coordinator
    a. The resource switches from the Scheduling Coordinator which negotiated the opportunity cost to another Scheduling Coordinator.
    b. The resource is acquired by a different Scheduling Coordinator through a merger or acquisition but keeps the same Scheduling Coordinator identifier in the Master File.
6. Change in resource attributes/status
    a. The resource changes ID/name in the Master File.
    b. The resource switches to being an MSG resource from being a non-MSG resource or the resource switches from being an MSG resource to being a non-MSG resource.
    c. The resource switches the type of fuel it uses.
    d. The resource's air permit restriction changes.
    e. The resource or a configuration within it (for an MSG resource) retires.
7. Change in negotiated elements
    a. Conditions underlying the resource's negotiated opportunity costs are no longer applicable or accurate.
    b. Vendor data is no longer available to use for a negotiated element in the negotiated opportunity cost calculation.
    c. Change/expiry of the tariff rates/fees/taxes/adders included in the negotiated opportunity cost calculation.

8. Change in any other material item which might affect the opportunity cost approved as an opportunity cost adder to the variable cost option for the default energy bid or as an adder to the commitment cost bid cap.

It is the responsibility of the Scheduling Coordinator to: (1) ensure that the conditions and data underlying any opportunity cost created as an opportunity cost adder to the variable cost option for the default energy bid or as an adder to the commitment cost bid caps for a resource accurately reflect current conditions; and (2) notify the CAISO of any changes that may affect their negotiated opportunity cost. To the extent that any opportunity cost created as an opportunity cost adder to the variable cost option for the default energy bid or as an adder to the commitment cost bid cap for the resource or MSG configurations require modification or reinstatement after termination, they will be re-established under the process for creating negotiated opportunity costs. To the extent that a negotiated opportunity cost is terminated, the opportunity cost will remain in place for the balance of the month and will default to zero for the following month and until a new negotiated opportunity cost is established.

N.5 Opportunity Cost Calculation for New Use-Limited Resources with Insufficient Data

A new Use-Limited Resource without 12 months of fifteen-minute LMPs for energy at the resource's PNode or aggregated PNode may elect to use the registered cost option (see Sections 30.4 and 30.4.1.2 of the CAISO Tariff) and remain on that option for up to 14 months after the resource is established in the market. Pricing data includes fuel region and the resource's PNode or aggregated PNode LMP data.

The alternative to electing the registered cost option is to elect the proxy cost option (see Sections 30.4 and 30.4.1.1 of the CAISO Tariff), pursuant to which the calculation of opportunity costs of foregone profits under the equations set forth in Section N.2.2 above will be based on energy revenues at a comparable PNode or aggregated APNode. If the CAISO can identify a PNode or aggregated APNode that is comparable to the new resource's node, the CAISO will use this pricing location as a reference in the calculation.

As of 14 months after a new resource is established in the market, the Scheduling Coordinator will no longer be able to select the registered cost option and must instead use the proxy cost option or request a negotiated opportunity cost.

Addendum to Market Instruments BPM (Based on Ver.39)

A Addendum for changes

Due to Aliso Canyon gas-electric coordination initiative and the interim tariff revisions from December 16th, 2018 through December 31, 2019. This Addendum will address the modification based on Version 39 of the Market Instruments BPM as follows;

Number	Feature	Tariff Section Numbers	Effective Date	BPM section	Existing section in MO BPM	Modified section in MO BPM	Expiration Date
1	Make two-day ahead advisory schedules available with the clarification that they are not financially binding or operationally binding	6.5.2.2.3	6/2/2016	10 & 12	See below	See below	December 31, 2019
2	Use current gas price information to increase efficiency of economic dispatch	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)	7/6/2016	Attachment C	See below	See below	made permanent
3	Adjust the gas price indexes used to calculation commitment and default energy bids & generated bids for affected resources on the SoCalGas/SDG&E system	39.7.1.1.1.3 (d)	7/6/2016	Attachment C	See below	See below	Made permanent
4	Permit market participants to rebid commitment costs in the real-time market	30.5.1(b)	6/2/2016	4.1, 5.1.1.1.1, 5.1.1.1.2, 8.2.1.3, B.2.1, G.2.1.1,	See below	See below	made permanent

				G2.1.2			
6	Introduce a constraint as needed into the CAISO's market processes to limit the affected gas area burn to a maximum	27.11	6/2/2016	new Attachment N	See below	See below	December 31, 2019

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.

Exhibit 0-1.1: Summary of CMRI Reports

Title	Contents
Day-Ahead Generation Market Results	Day-Ahead Energy Schedules, Ancillary Services Awards, Load Following and RUC Capacity for Generating Units
Day-Ahead Demand Market Results	Day-Ahead Energy Schedules and Ancillary Services Awards of Participating Loads and Day-Ahead Energy Schedules for Non-Participating Loads
Day-Ahead Residual Unit	RUC Capacity and RUC Awards from the Residual Unit Commitment

Title	Contents
Commitment (RUC) Capacity	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.
Two Day-Ahead Residual Unit Commitment (RUC) Advisory Schedules	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).
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.
Day-Ahead Start-Up Instructions	Start-Up instructions resulting from the RUC process
Day-Ahead Ancillary Service Market Results	Resource-specific Ancillary Service Awards resulting from the Integrated Forward Market run
Day-Ahead Market Power Mitigation (MPM) Results	Segments of the "new" or mitigated Bid as a result of the Day-Ahead Market Power Mitigation Process (MPM)
HASP Market Power Mitigation (MPM) Results	Segments of the "new" or mitigated Bid as a result of the HASP Market Power Mitigation Process (MPM)
FMM Market Power Mitigation (MPM) Results	Segments of the "new" or mitigated Bid as a result of the FMM Market Power Mitigation Process (MPM)
Default Energy Bid Curves	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.
Day-Ahead Generation Commodity Prices	Day-Ahead resource-specific prices (for Energy Schedules, Ancillary Services Awards, RUC Awards) of Generating Units
Day-Ahead Demand Commodity Prices	Day-Ahead resource-specific prices for Energy Schedules and Ancillary Services Awards of Participating Loads; and resource-

Title	Contents
	specific prices for Energy Schedules of Non-Participating Loads
Hour Ahead Scheduling Process (HASP) Schedules	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.
Hour Ahead Scheduling Process (HASP) Schedule Prices	Displays Hour-Ahead Scheduling Process advisory resource-specific prices for the next Trading Hour.
Fifteen-Minute Market (FMM) Schedules	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.
Fifteen-Minute Market (FMM) Schedule Prices	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.
Day Ahead Finally Qualified Load Following Capacity	Day-Ahead Finally Qualified Load Following Up and Down Capacity for Metered Subsystems (MSS) resources
Day-Ahead Unit Commitments	Resources that are self-committed or CAISO committed by the IFM or RUC process in the Day-Ahead Market
Default RMR Minimum Load & Startup Cost Bid Curves	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.
Day-Ahead Import-Export Commodity Prices	Day-Ahead resource-specific prices (for Energy Schedules, Ancillary Services Awards, RUC Awards) of System Resources
Extremely Long Start Resource Startup Instructions	Startup instructions resulting from the Extremely Long Start Commitment (ELC) process. This report is not currently active.
Day-Ahead Reliability Must Run (RMR) Dispatches	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
Expected Energy Allocation Details	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

Title	Contents
	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
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

Title	Contents
Real-Time Dispatch (RTD) Schedule Prices	Reports the 5-minute interval based resource level binding prices from the real-time 5-minute market runs.
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 • PrimaryFlowgate identifier • SecondaryFlowgate 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*

Title	Contents
	Business Practice Manual document for more information.
Flexible Ramp Requirement Sufficiency 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.
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.
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.

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) [58]

- **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.

[58] Greenhouse Gas component is only applicable to the Energy Imbalance Market (EIM)

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.

- **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 reports 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.

Number 2 & 3

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 ITCS59 (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.[60]

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:

Gas Price Index hubs	Gas Price Index plus applicable regional transportation adder

[59] ITCS means Interstate Transition Cost Surcharges.

[60] If the Facility does not qualify for service under Rate Schedule G-EG, the applicable rate shall be given by Rate Schedule G-NT.

PG&E Citygate	PGE2
SoCal Citygate	SCE1
	SCE2
	SDGE1
	SDGE2

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.

Source	Earliest Time Available (PST)	Latest Time Available (PST)
ICE	11:30 AM	12:00 PM
SNL Energy/BTU Daily	16:00 PM	19:00 PM

NGI	**19:00 PM**	**2:00 AM (flow date)**
Platt's	**17:00 PM**	**19:00 PM**

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.

Number 4

○ 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 , 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

	Daily Components	Hourly Components	Submitted through SIBR	Comment
Start-Up	✓		**Yes, only if proxy cost option is currently effective for Start-Up Cost in Master File.**	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.
Minimum Load	✓		**Yes, only if Proxy Cost option is currently**	If the resource has elected to use Registered Cost, the Minimum Load cost

	Daily Components	Hourly Components	Submitted through SIBR	Comment
			effective for Minimum Load Cost in Master File.	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.
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				Bid cannot contain more than certified quantities for each service.
Regulation Down		✓	✓	
Regulation Up		✓	✓	
Spinning Reserve		✓	✓	
Non-Spinning Reserve		✓	✓	
Ramp Rate	✓		✓	Bid by SC, within limits of the minimum and maximum Ramp Rates in the Master File.

	Daily Components	Hourly Components	Submitted through SIBR	Comment
Operational Ramp Rate	✓		✓	
Operating Reserve Ramp Rate	✓		✓	
Regulation Ramp Rate	✓		✓	
Contingency Dispatch Indicator	✓		✓	Must be selected if any AS is part of the Bid/Schedule.
Intertie Minimum Hourly Block (DA)		✓	✓	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.
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

	Daily Components	Hourly Components	Submitted through SIBR	Comment
				in each 5 minute Dispatch Interval of a Trading Hour.
Pump Shut-Down Cost		✓	✓	
Pumping Cost		✓	✓	
Energy Limit (Maximum and Minimum Daily)	✓		✓	
RUC		✓	✓	
Capacity Limit		✓	✓	(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.
Distribution Factors		✓	✓	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.

	Daily Components	Hourly Components	Submitted through SIBR	Comment
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)

Generation Technology	Recommended VOM Cost Adder ($/MWh)
Solar	$0.00
Nuclear	$1.00
Coal	$2.00
Wind	$2.00
Hydro	$2.50
Combined Cycle and Steam	$2.80
Geothermal	$3.00
Landfill Gas	$4.00
Combustion Turbine & Reciprocating Engine	$4.80
Biomass	$5.00

A5.1.1.1.1 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.[61] 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

	Cooling Time (Minutes)	Start-Up Time (Minutes)	Start-Up Cost ($)
Warm	0	600	6,500
Intermediate	240	1390	9,800
Cold	480	1400	12,000

[61] 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.[62]

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.

[62] 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:

    a. Start-Up Energy Cost Curve (registered Start-Up Energy * Energy Price Index).

    b. Start-Up Fuel Cost Curve (registered Start-Up Fuel * Gas Price Index).

    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.

Start-Up Cost Curve = Start-Up Energy Cost Curve + Start-Up Fuel Cost Curve + Greenhouse Gas Start-Up Cost Allowance Curve + Major Maintenance Start-Up Cost Adder + GMC Start-Up Cost Adder.

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:

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

6. 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.

7. Greenhouse Gas Allowance Minimum Load Cost - the product of the Greenhouse Gas Minimum Load Cost Allowance and the registered Minimum Load (if applicable – see Attachment K for details).

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

9. 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.

10. Relative Proxy Minimum Load Cost Ceiling (125%) – for validation of submitted Minimum Load Bid Component.

Minimum Load Cost = Minimum Load Fuel Cost + Operation and Maintenance Minimum Load Cost + Greenhouse Gas Allowance Minimum Load Cost + Major Maintenance Minimum Load Cost Adder + GMC Minimum Load Cost Adder.

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:

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

6. 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.

7. 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:

Operating Levels	Average Heat Rate	Gas price index	Operation & Maintenance Cost	Grid Management Charge adder
70	14440	$5.5	$2.80	$0.50
150	11960			
300	10909			
485.17	10366			

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.

Segment 1 – (**53.85** + 2.80 + 0.50) = **$57.15**

Segment 2 – (**54.22** + 2.80 + 0.50) = **$57.52**

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

Minimum Load Cost = Minimum Load Fuel Cost + (O&M * Minimum Operating Level) + Greenhouse Gas Allowance Minimum Load Cost + Major Maintenance Minimum Load Cost Adder + GMC Minimum Load Cost Adder

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.

Master File Field Name (RDT Column Name)	Definition	Parameter and/or Enumerations
MAX_GEN (Maximum Generation Capacity)	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.	Cannot be null
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.
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_STRT (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

Master File Field Name (RDT Column Name)	Definition	Parameter and/or Enumerations
MIN_LOAD_COST (Minimum Load Cost)	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.
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_TYPE = GEN or TG then ML_COST_BASIS_TYPE cannot 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_TYPE = GEN or TG then SU_COST_BASIS_TYPE cannot be null, must be filled with one of the following: PRXC - Proxy Cost REGC - Registered Cost
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

Master File Field Name (RDT Column Name)	Definition	Parameter and/or Enumerations
PUMP_MIN_UP_TM (Pump Minimum Up Time)	The minimum time that a Pumped Storage Hydro Resource must stay in pumping mode after switching to that mode.	Cannot be null if GEN_TECH_TYPE equals either PTUR or PUMP
PUMP_MIN_DWN_TM (Pump Minimum Down Time)	The minimum time that a Pumped Storage Hydro Resource must stay out of pumping mode after switching out of that mode.	
MIN_DWN_TM_GP	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.	
MIN_DWN_TM_PG	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.	
MAX_PUMP_SD_CST (Pump Maximum Shutdown Cost)	The maximum cost it would take to shutdown the pump.	MAX_PUMP_SD_CST cannot be null if GEN_TECH_TYPE = PTUR or PUMP
PUMP_SHTDWN_TM (Pump Shutdown Time)	The pump shutdown time	
COST_RANK_LMPM (Variable Cost Option)	A method of calculating Default energy Bids based on fuel costs and variable operations and maintenance costs.	Rank 1, 2, or 3
NEGO_RANK_LMPM (Negotiated Rate Option)	A method of calculating Default energy Bids based on a negotiation with the CAISO or the Independent Entity.	Rank 1, 2, or 3
PRC_RANK_LMPM (LMP Option)	A method of calculating Default energy Bids based Locational Marginal Prices.	Rank 1, 2, or 3
RSRV_CAP_SPIN (Reserve Capacity: Spin)	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.	
RSRV_CAP_NSPIN (Reserve Capacity: Non-Spin)	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.	

Master File Field Name (RDT Column Name)	Definition	Parameter and/or Enumerations
CERT_REG (Certified for AS: Regulation - CERT_REG)	An identifier of a resource that is certified to provide Regulation Reserve.	
CERT_SPIN (Certified for AS: Spin - CERT_SPIN)	An identifier of a resource that is certified to provide Spinning Reserve.	
CERT_NSPIN_DAM (Certified for AS DAM: Non-Spin - CERT_DAM_NON_SPIN)	An identifier of a resource that is certified to provide Non-Spinning Reserve in the DAM.	
CERT_NSPIN_RTM (Certified for AS RTM: Non-Spin - CERT_RTM_NON_SPIN)	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.	
REM (Regulation Energy Management)	Indicator of a non-generator resource that can only provide regulation energy	
MIN_CONT_ENERGY_LIMIT (Minimum Continuous Energy Limit)	Minimum stored energy for an NGR. If no real physical energy limit, leave blank.	
MAX_CONT_ENERGY_LIMIT (Maximum Continuous Energy Limit)	Maximum stored energy for an NGR. If no real physical energy limit, leave blank.	
CURT_ENERGY_LIMIT (Curtailment Energy Limit)	The energy limit for curtailing the consumption of energy for NGR. If no limit, leave blank. This is a placeholder for future functionality.	
ENERGY_EFFIC (Energy Efficiency)	The percentage of charging energy that the device can store and later discharge; 0<= n <=1	
RMT_MAX_ON_PEAK	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.	
RMT_MAX_ON_PEAK_EXP_DT	Expiration date of the stated RMTG-eligible capacity	

Master File Field Name (RDT Column Name)	Definition	Parameter and/or Enumerations
RMT_MAX_OFF_PEAK	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.	
RMT_MAX_OFF_PEAK_EXP_DT	Expiration date of the stated RMTG-eligible capacity	
EMISSION_RATE	For gas-fired resources, the emission rate (mtCO2/mmBTU) used to determine a resource's greenhouse gas compliance obligation	
GHG_COMPLIANCE_OBLIG	Indicator of a resource that has a green house gas compliance obligation and is, therefore, eligible to recover greenhouse gas allowance costs	
FORECAST_OWNER	Indicator for whether a resource will provide its own forecast or will utilize the ISO's forecast	

G.2.1.1 Maximum Proxy Cost Start-up Costs

For purposes of determining maximum Start-up costs[63] 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.

[63] 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.[64] 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.

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)

[64] 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/$mtCO_2e$
GHG Emission Rate = 0.053165 $mtCO_2e$ /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 $mtCO_2e$ /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)

	Cooling Time (minutes)	Start-Up Time (minutes)	Start-Up Fuel (MMBtu)	Start-Up Energy (MWh)	Start-Up Cost w/o GHG/MMA ($)	Start-Up Cost with GHG & MMA ($)	Max Start-Up Bid w/o GHG/MMA ($)	Max Start-Up Bid with GHG & MMA ($)
Hot	0	600	1,083	20	\$10,856	\$12,540	\$13,569	\$15,675
Warm	240	1390	1,633	40	\$17,196	\$19,329	\$21,495	\$24,161

Cold	480	1400	2,000	60	$21,917	$24,349	$27,396	$30,436

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[65] x 20MW) + ($0.50/MWh x 20MW)
= ($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 $mtCO_2e$ /MMBtu
GHG Allowance Price = $15.34/$mtCO_2e$

= (0.001 x 14,000Btu/kWh x 20MW x $8.50/MMBtu) + ($4/MWh * 20MW) + ($0.50/MWh x 20MW) + (20MW x 0.001 x 14,000Btu/kWh x 0.053165 mtCO2/MMBtu x 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
= $2,698 + 105
= $2,803

Table G4. Example of Calculated Minimum Load Cost and Maximum Bid Calculation
Gas Price Index = $8.50/MMBtu

Minimum Operating Level (MW)	Heat Rate (MBtu/ MWh)	O&M Cost ($/MWh)	Minimum Load Cost ($)	GHG Allowance Cost & MMA ($/MWh)	Minimum Load Cost with GHG & MMA ($)	Max MLC Bid w/o GHG/MMA ($)	Max MLC Bid with GHG & MMA ($)

[65] This example assumes a $4/MWh O&M adder.

20	14,000	4	$2,470	$333	$2,803	$3,088	$3,504

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.