# 4. Roles and Responsibilities

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## 4.5 Responsibilities of a Scheduling Coordinator

### 4.5.1 Scheduling Coordinator Certification

Only Scheduling Coordinators that the CAISO has certified as having met the requirements of this Section 4.5.1 may participate in the Day-Ahead Market or Real-Time Market or submit Supply Plans or RA Plans. Scheduling Coordinators offering Ancillary Services shall additionally meet the requirements of Section 8.

Each Scheduling Coordinator shall:

(a) demonstrate to the CAISO's reasonable satisfaction that it is capable of performing the functions of a Scheduling Coordinator under this CAISO Tariff including (without limitation) the functions specified in Sections 4.5.3 and 4.5.4 as applicable;

(b) identify each of the Eligible Customers (including itself if it trades for its own account) which it is authorized to represent as Scheduling Coordinator and confirm that the metering requirements under Section 10 are met in relation to each Eligible Customer that it represents under this CAISO Tariff;

(c) identify each of the Convergence Bidding Entities that it is authorized to represent as Scheduling Coordinator;

(d) confirm that each of the End-Use Customers it represents is eligible for service as a Direct Access End User;

(e) confirm that none of the Wholesale Customers it represents is ineligible for wholesale transmission service pursuant to the provisions of FPA Section 212(h);

(f) demonstrate to the CAISO’s reasonable satisfaction that it meets the financial criteria set out in Section 12;

(g) enter into a Scheduling Coordinator Agreement with the CAISO; and

(h) provide NERC tagging data, as applicable.

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### 4.5.3 Responsibilities of a Scheduling Coordinator

Each Scheduling Coordinator shall be responsible for:

**4.5.3.1 Obligation to Pay**

Paying the CAISO’s charges in accordance with this CAISO Tariff;

**4.5.3.2 Submit Bids and Interchange Schedules**

**4.5.3.2.1** Submitting Bids, including Self-Schedules, in CAISO Markets that relate to the Market Participants for which it serves as Scheduling Coordinator;

**4.5.3.2.2** Submitting Interchange Schedules prepared in accordance with all NERC, WECC and CAISO requirements, including providing E-Tags for all applicable transactions pursuant to WECC practices. The CAISO shall not accept E-Tags for ten-minute recallable reserve transactions (i.e., transactions with a WECC energy product code of “C-RE”). The CAISO is not, and shall not be listed as, the “Purchasing Selling Entity” for purposes of E-Tags. Title to Energy shall pass directly from the entity that holds title when the Energy enters the CAISO Controlled Grid to the entity that removes the Energy from the CAISO Controlled Grid, in each case in accordance with the terms of this CAISO Tariff.

**4.5.3.3 Modifications in Demand Supply**

Coordinating and allocating modifications in Demand and exports and Generation and imports at the direction of the CAISO in accordance with this CAISO Tariff;

**4.5.3.4 Inter-SC Trades**

Submitting any applicable Inter-SC Trades that the Market Participants intend to have settled through the CAISO Markets, pursuant to this CAISO Tariff;

**4.5.3.5 Tracking and Settling Trades**

Tracking and settling all intermediate trades, including bilateral transactions and Inter-SC Trades, among the entities for which it serves as Scheduling Coordinator;

**4.5.3.6 Ancillary Services**

Providing Ancillary Services in accordance with Section 8;

**4.5.3.7 [Not Used]**

**4.5.3.8 Business Practice Manuals**

Complying with all CAISO Business Practice Manuals and ensuring compliance by each of the Market Participants which it represents with all applicable provisions of the Business Practice Manuals;

**4.5.3.9 Interruptible Imports**

Identifying any Interruptible Imports included in its Bids or Inter-SC Trades;

**4.5.3.10 Participating Intermittent Resources**

Submitting Bids, including Self-Schedules, for Participating Intermittent Resources consistent with the CAISO Tariff;

**4.5.3.11 Day-Ahead Market Published Schedules and Awards**

Starting-up units and timely achieving specified operating levels in response to Dispatch Instructions, in accordance with CAISO published Schedules and awards;

**4.5.3.12 Financial Responsibility**

Assuming financial responsibility for all Schedules, AS Awards and Dispatch Instructions issued in the CAISO Markets, and all Virtual Awards in accordance with the provisions of this CAISO Tariff;

**4.5.3.13 Compliance with Environmental Constraints, Operating Permits and Applicable Law**

Submitting Bids so that any service provided in accordance with such Bids does not violate environmental constraints, operating permits or applicable law. All submitted Bids must reflect resource limitations and other constraints as such are required to be reported to the CAISO Control Center;

**4.5.3.14 Tax Compliance**

Providing, as described in the Business Practice Manuals, resale certificates or other proof acceptable to CAISO that its purchases of energy are exempt from any sales and use taxes that otherwise might apply; and

**4.5.3.15 SQMD Plan**

Complying with the SQMD Pan for eligible entities it serves pursuant to Section 10.3.7.

**4.5.3.16 RA Plans and Supply Plans**

Providing RA Plans for LSEs or CPEs for which it serves as Scheduling Coordinator and providing Supply Plans for Resource Adequacy Resources for which it serves as Scheduling Coordinator. If a CPE is also a Load Serving Entity and the CPE and Load Serving Entity are represented by the same Scheduling Coordinator, that Scheduling Coordinator must use distinct Scheduling Coordinator ID Codes for its activities related to the CPE and Load Serving Entity functions.

### 4.5.4 Operations of a Scheduling Coordinator

**4.5.4.1 Maintain Twenty-four (24) Hour Scheduling Centers**

Each Scheduling Coordinator other than a Scheduling Coordinator that represents only Convergence Bidding Entities shall operate and maintain a twenty-four (24) hour, seven (7) days per week, scheduling center. Each Scheduling Coordinator shall designate a senior member of staff as its scheduling center manager who shall be responsible for operational communications with the CAISO and who shall have sufficient authority to commit and bind the Scheduling Coordinator.

**4.5.4.2 [Not Used]**

**4.5.4.3 Dynamic Scheduling**

**4.5.4.3.1 Dynamic Scheduling of Imports**

Scheduling Coordinators may submit Bids for imports of Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services for which associated Energy is delivered from Dynamic System Resources located outside of the CAISO Balancing Authority Area, provided that: (a) such dynamic scheduling is technically feasible and consistent with NERC and WECC reliability standards and any requirements of the NRC, (b) all operating, technical, and business requirements for dynamic scheduling functionality, as set forth in the Dynamic Scheduling Protocol in Appendix M or posted in standards on the CAISO Website, are satisfied, (c) the Scheduling Coordinator for the Dynamic System Resource executes a Dynamic Scheduling Agreement for Scheduling Coordinators as provided in Appendix B.5 with the CAISO for the operation of dynamic scheduling functionality, and (d) all affected Balancing Authorities each execute with the CAISO a Dynamic Scheduling Host Balancing Authority Operating Agreement as provided in Appendix B.9, or a special operating agreement particular to the operation of dynamic functionality.

**4.5.4.3.2 Dynamic Scheduling of Exports of Energy**

Scheduling Coordinators may submit Bids for Dynamic Schedules of exports of Energy from Generating Units located in the CAISO Balancing Authority Area, provided that: (a) such dynamic scheduling is technically feasible and consistent with NERC and WECC reliability standards and any requirements of the NRC, (b) all operating, technical, and business requirements for dynamic scheduling functionality, as set forth in the Dynamic Scheduling Protocol in Appendix M or posted in standards on the CAISO Website, are satisfied, (c) the Scheduling Coordinator for the Generating Unit executes a Dynamic Scheduling Agreement for Scheduling Coordinators as provided in Appendix B.5 with the CAISO for the operation of dynamic scheduling functionality, and (d) all affected Balancing Authorities each execute with the CAISO an operating agreement particular to the operation of dynamic functionality.  Scheduling Coordinators may not submit Bids for Dynamic Schedules of exports of Ancillary Services from resources located in the CAISO Balancing Authority Area, nor may Scheduling Coordinators submit Bids for Dynamic Schedules of exports from Loads located in the CAISO Balancing Authority Area.

**4.5.4.4 Termination of Scheduling Coordinator Agreement and Suspension of Certification**

(a) A Scheduling Coordinator's Scheduling Coordinator Agreement may be terminated by the CAISO on written notice to the Scheduling Coordinator:

(i) if the Scheduling Coordinator no longer meets the requirements for eligibility set out in Section 4.5 and fails to remedy the default within a period of five (5) Business Days after the CAISO has given written notice of the default;

(ii) if the Scheduling Coordinator fails to pay any sum under this CAISO Tariff and fails to remedy the default within a period of five (5) Business Days after the CAISO has given written notice of the default;

(iii) if the Scheduling Coordinator commits any other default under this CAISO Tariff or any of the CAISO Business Practice Manuals which, if capable of being remedied, is not remedied within thirty (30) days after the CAISO has given it written notice of the default; or

(iv) if the Scheduling Coordinator does not participate in the CAISO’s markets for Energy, Imbalance Reserves, Reliability Capacity, or Ancillary Services for a period of twelve (12) consecutive months and fails to comply with the provisions of Section 4.5.4.4.2 within 120 days after the CAISO has given it written notice of the CAISO’s intent to terminate its Scheduling Coordinator Agreement.

(b) A Scheduling Coordinator’s Scheduling Coordinator Agreement may be terminated by the Scheduling Coordinator on sixty (60) days written notice to the CAISO, provided that such notice shall not be effective to terminate the Scheduling Coordinator Agreement until the Scheduling Coordinator has complied with all applicable requirements of Section 4.5.2.

(c) The CAISO shall, following termination of a Scheduling Coordinator Agreement and within thirty (30) days of being satisfied that no sums remain owing by the Scheduling Coordinator under the CAISO Tariff, return or release to the Scheduling Coordinator, as appropriate, any money or credit support provided by such Scheduling Coordinator to the CAISO under Section 12.

**4.5.4.4.1** Pending the effective date of termination of service pursuant to Section 4.5.4.5.1, the CAISO will suspend the certification of a Scheduling Coordinator which has received a notice of termination under Section 4.5.4.4(a) and the Scheduling Coordinator will not be eligible to participate in the CAISO’s markets for Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services.

**4.5.4.4.2** A Scheduling Coordinator that has received a notice of the CAISO’s intent to terminate its Scheduling Coordinator Agreement for failure to participate in the CAISO’s markets for Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services for a period of twelve (12) consecutive months pursuant to Section 4.5.4.4(a)(iv) will avoid having its Scheduling Coordinator Agreement terminated and will have its certification reinstated if it completes the testing and training required for Scheduling Coordinator certification as set forth in the applicable Business Practice Manual within 120 days after the CAISO’s issuance of the notice of intent to terminate.

**4.5.4.5 Notification of Termination**

The CAISO shall, promptly after providing written notice of default to a Scheduling Coordinator as specified in Section 4.5.4.4(a), notify the Scheduling Coordinators that could be required to represent End User Eligible Customers of the Scheduling Coordinator under Section 4.5.4.6.2 if the default is not cured. The CAISO shall, as soon as reasonably practicable following the occurrence of any of the events specified in Section 4.5.4.4, notify the Scheduling Coordinator and the Scheduling Coordinators that could be required to represent End User Eligible Customers of the defaulting Scheduling Coordinator, and the UDCs, and shall as soon as reasonably practicable after the issuance of such notice of termination post such notice on the CAISO Website. Termination of the Scheduling Coordinator Agreement will automatically remove the Scheduling Coordinator’s certification under Section 4.5 and Section 8.4.

**4.5.4.5.1 Filing of Notice of Termination**

Any notice of termination given pursuant to Section 4.5.4.4 shall also be filed by the CAISO with FERC, if required by FERC rules, if the non-compliance is not remedied within the period specified in Section 4.5.4.4, and it shall be effective in accordance with FERC rules.

**4.5.4.6 Continuation of Service on Termination**

**4.5.4.6.1 Option for Eligible Customers to choose a new Scheduling Coordinator**

When the CAISO suspends the certification of a Scheduling Coordinator pending termination, Eligible Customers of the defaulting Scheduling Coordinator shall be entitled to select another Scheduling Coordinator to represent them. The CAISO will post notice of any suspension on the CAISO Website. Until the CAISO is notified by another Scheduling Coordinator that it represents an Eligible Customer of the defaulting Scheduling Coordinator, the Eligible Customer of the defaulting Scheduling Coordinator will receive interim service in accordance with Section 4.5.4.6.2.

**4.5.4.6.2 Interim Service**

The CAISO shall maintain a list of Scheduling Coordinators willing to represent Eligible Customers of a defaulting Scheduling Coordinator, which list may be differentiated by UDC service area.  Scheduling Coordinators who indicate to the CAISO their desire to be on such list shall be placed thereon by the CAISO in random order.

(a) When the CAISO suspends the certification of a Scheduling Coordinator in accordance with Section 4.5.4.4.1, Eligible Customers of the defaulting Scheduling Coordinators shall be assigned to all Scheduling Coordinators on the list established pursuant to this Section 4.5.4.6.2 in a non-discriminatory manner to be established by the CAISO, and each Eligible Customer shall thereafter be represented by the Scheduling Coordinator to which it is assigned unless and until it selects another Scheduling Coordinator in accordance with Section 4.5.4.6.1, subject to this Section 4.5.4.6.2 subsection (b).

(b) Unless the CAISO is notified by another Scheduling Coordinator that it represents an Eligible Customer of a defaulting Scheduling Coordinator within seven (7) days of the notice of termination being posted on the CAISO Website, the Scheduling Coordinator to which that Eligible Customer has been assigned in accordance with subsection (a) may establish a reasonable minimum period for service, not to exceed thirty (30) days.

(c) In the event no Scheduling Coordinator indicates its willingness to represent Eligible Customers of a defaulting Scheduling Coordinator, the UDC that has the obligation to serve End-Use Customers of the Eligible Customer, if any, shall arrange to serve those End-Use Customers of such Eligible Customers that are located within the service area of the UDC. Such service will be provided in a manner consistent with that which the UDC provides, pursuant to the rules and tariffs of the Local Regulatory Authority, for its bundled End-Use Customers.

(d) This Section shall not in any way require a UDC to provide or arrange for Scheduling Coordinator service for wholesale Eligible Customers.

## 4.6 Relationship Between CAISO and Generators

The CAISO shall not accept Bids for any Generating Unit interconnected to the electric grid within the CAISO Balancing Authority Area (which includes a Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area) otherwise than through a Scheduling Coordinator.  The CAISO shall further not be obligated to accept Bids from Scheduling Coordinators relating to Generation from any Generating Unit, including Generating Units participating as Non-Generator Resources, interconnected to the electric grid within the CAISO Balancing Authority Area  (which includes a Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area) unless the relevant Generator undertakes in writing, by entering into a Participating Generator Agreement or, if eligible to enter such an agreement under the applicable terms of the CAISO tariff, a Net Scheduled PGA, Pseudo-Tie Participating Generator Agreement, or Metered Subsystem Agreement, with the CAISO to comply with all applicable provisions of this CAISO Tariff as they may be amended from time to time, including, without limitation, the applicable provisions of this Section 4.6 and Section 7.7.  The CAISO shall not accept Bids from Scheduling Coordinators relating to Participating Loads using the Non-Generator Resource model unless the resource owner or operator undertakes in writing, by entering into a Participating Load Agreement, to comply with all applicable provisions of this CAISO Tariff as they may be amended from time to time including, without limitation, the applicable provisions of this Section 4.6 and Section 7.7.

### 4.6.1 General Responsibilities

**4.6.1.1 Operate Pursuant to Relevant Provisions of CAISO Tariff**

Participating Generators shall operate, or cause their facilities to be operated, in accordance with the relevant provisions of this CAISO Tariff, including, but not limited to, the operating requirements for normal and emergency operating conditions specified in Section 7 and the requirements for the dispatch and testing of Ancillary Services specified in Section 8.

(i) Each Participating Generator shall immediately inform the CAISO, through its respective Scheduling Coordinator, of any change or potential change in the current status of any Generating Units that are under the Dispatch control of the CAISO.  This will include, but not be limited to, any change in status of equipment that could affect the maximum output of a Generating Unit, the Minimum Load of a Generating Unit, the ability of a Generating Unit to operate with automatic voltage regulation, operation of the PSSs (whether in or out of service), the availability of a Generating Unit governor, or a Generating Unit’s ability to provide Ancillary Services as required.  Each Participating Generator shall immediately report to the CAISO, through its Scheduling Coordinator, any actual or potential concerns or problems that it may have with respect to Generating Unit direct digital control equipment, Generating Unit voltage control equipment, or any other equipment that may impact the reliable operation of the CAISO Controlled Grid.

(ii) In the event that a Participating Generator cannot meet its Generation schedule as specified in the Day-Ahead Schedule, or comply with a Dispatch Instruction, whether due to a Generating Unit trip or the loss of a piece of equipment causing a reduction in capacity or output, the Participating Generator shall notify the CAISO, through its Scheduling Coordinator, at once.  If a Participating Generator will not be able to meet a time commitment or requires the cancellation of a Generating Unit Start-Up, it shall notify the CAISO, through its Scheduling Coordinator, at once.

(iii) In addition to complying with the other requirements of this Section 4.6.1.1 regarding the operation of its Generating Unit, a Participating Generator with a Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area shall comply with the requirements of Section 1.2.1 and related provisions of the Pseudo-Tie Protocol in Appendix N.

**4.6.1.2 Operate Pursuant to Relevant Operating Procedures**

Participating Generators shall operate, or cause their Generating Units and associated facilities to be operated, in accordance with the relevant Operating Procedures and Business Practice Manuals established by the CAISO or, prior to the establishment of such procedures, the Operating Procedures established by the TO or UDC owning the facilities that interconnect with the Generating Unit of the Participating Generator.

### 4.6.2 [Not Used]

### 4.6.3 Requirements for Certain Participating Generators

**4.6.3.1 Participating Generators Directly Connected to a Distribution System**

With regard to any Generating Unit directly connected to a Distribution System, a Participating Generator shall comply with applicable UDC tariffs, requirements of the Local Regulatory Authority, interconnection requirements and generation agreements.  With regard to a Participating Generator’s Generating Units directly connected to a Distribution System, the CAISO and the UDC or MSS, as applicable, will coordinate to develop procedures to avoid conflicting CAISO and UDC or MSS, as applicable, operational directives.

**4.6.3.2 Exemption for Generating Units Less Than One (1) MW**

A Generator with a Generating Unit directly connected to a Distribution System will be exempt from compliance with this Section 4.6 and Section 10.1.3 in relation to that Generating Unit provided that (i) the rated capacity of the Generating Unit is less than one (1) MW, and (ii) the Generator does not use the Generating Unit to participate in the CAISO Markets. This exemption in no way affects the calculation of or any obligation to pay the appropriate charges or to comply with all the other applicable Sections of this CAISO Tariff.  A Generating Unit with a rated capacity of less than 500 kW, unless the Generating Unit is (a) participating in an aggregation agreement approved by the CAISO or (b) a storage resource with a rated capacity of 100 kW or more, is not eligible to participate in the CAISO Markets and the Generator is not a Participating Generator for that Generating Unit.

With regard to any Generating Unit directly connected to a UDC system, a Participating Generator shall comply with applicable UDC tariffs, interconnection requirements and generation agreements.  With regard to a Participating Generator’s Generating Units directly connected to a UDC system, the CAISO and the UDC will coordinate to develop procedures to avoid conflicting CAISO and UDC operational directives. With regard to Regulatory Must-Take Generation, the CAISO will honor applicable terms and conditions of existing agreements, including Existing QF Contracts, as specified in Section 4.6.3.2. Qualifying Facilities that are not Regulatory Must-Take Generation subject to an Existing QF Contract shall comply with the requirements applicable to Participating Generators, as specified in Section 4.6.3.3.

**4.6.3.3 Qualifying Facilities and Combined Heat and Power Resources**

The owner or operator of (1) a Qualifying Facility, (2) a resource that is subject to an Amended QF Contract, or (3) a Combined Heat and Power Resource may satisfy the requirements of Section 4.6, to the extent applicable, by entering into Net Scheduled Participating Generator Agreement (Net Scheduled PGA) with the CAISO, in which case it shall comply with the provisions of the Net Scheduled PGA and Section 4.6.3.4. In order to be eligible to enter into the Net Scheduled PGA, a Participating Generator must demonstrate to the CAISO (a) that its Generating Unit (1) has established QF status pursuant to PURPA, (2) is a party to an Amended QF Contract; or (3) is a CHP Resource and (b) that the Self-provided Load of the Participating Generator that is served by the resource either (1) has and continues through the term of the Net Scheduled PGA to have, standby service from a UDC or MSS Operator under terms approved by the Local Regulatory Authority or FERC, as applicable, or (2) is curtailed concurrently with any Outage of the Generation serving that Self-provided Load in an amount sufficient to cover that Outage.

**4.6.3.4 Participating Generator with a Net Scheduled PGA**

A Participating Generator that is eligible for and has entered into a Net Scheduled Participating Generator Agreement shall be subject to the provisions of this Section 4.6.3.4, as reflected in the terms of the Net Scheduled PGA.

**4.6.3.4.1 Revenue Metering for a Net Scheduled Generating Unit**

In accordance with the terms of the Net Scheduled PGA and Section 10.1.3.3, a Participating Generator that has entered into a Net Scheduled PGA may net the revenue metering value for the Generation produced by each Net Scheduled Generating Unit listed in the Net Scheduled PGA and the revenue metering value for the Demand of the Self-provided Load that is (i) served by the Net Scheduled Generating Unit and (ii) electrically located on the same side of the Point of Demarcation.

**4.6.3.4.2 Telemetry for a Net Scheduled Generating Unit**

A Participating Generator that has entered into a Net Scheduled PGA may satisfy the provisions of Section 7.6.1(d) for the installation of telemetry by installing telemetry at the Point of Demarcation for the purpose of recording the net impact of the Net Scheduled Generating Unit upon the CAISO Controlled Grid; provided that the installed telemetry satisfies the technical, functional, and performance requirements for telemetry set forth in the CAISO Tariff and the applicable Business Practice Manual.

**4.6.3.4.3 Market and Settlement Processes for a Net Scheduled Generating Unit**

For bidding, scheduling, billing, and Settlement purposes regarding the Net Scheduled Generating Unit Self-provided Load of a Participating Generator that has entered into a Net Scheduled PGA, measurements of Generation or Demand of the Net Scheduled Generating Unit shall be made at the Point of Demarcation. In all other respects, the Generation and Load of the Net Scheduled Generating Unit shall be subject to the applicable provisions of the CAISO Tariff regarding bidding, scheduling, billing, and Settlements.

**4.6.3.4.4 Operating Requirements for a Net Scheduled Generating Unit**

A Participating Generator that has entered into a Net Scheduled PGA shall abide by CAISO Tariff provisions regarding the CAISO's ability to dispatch or curtail Generation from the Net Scheduled Generating Units listed in its Net Scheduled PGA. The CAISO shall only dispatch or curtail a Net Scheduled Generating Unit of the Participating Generator: (a) to the extent the Participating Generator bids Energy, Imbalance Reserves, Reliability Capacity, or Ancillary Services from the Net Scheduled Generating Unit into the CAISO Markets or the Energy is otherwise available to the CAISO under Section 40, subject to the restrictions on Dispatch Instructions or Operating Instructions set forth below; or (b) if the CAISO must dispatch or curtail the Net Scheduled Generating Unit in order to respond to an existing or imminent System Emergency or condition that would compromise CAISO Balancing Authority Area integrity or reliability as provided in Sections 7 and 7.6.1.

The CAISO will not knowingly issue a Dispatch Instruction or Operating Instruction to a Participating Generator that has entered into a Net Scheduled PGA that: (1) requires a Participating Generator to reduce its Generation below the delineated minimum operating limit, other than in a System Emergency; (2) conflicts with operating limitations provided to the CAISO by the Participating Generator; or (3) results in damage to the Participating Generator’s equipment, provided that any such equipment limitation has been provided to the CAISO and incorporated in the Participating Generator’s operating limitations. If the Participating Generator: (1) receives a Schedule which requires operation below the minimum operating limit, and (2) deviates from that Schedule to continue to operate at the minimum operating limit, it will not be subject to any penalties or sanctions as a result of operating at the minimum operating limit. The Participating Generator’s consequences for deviating from Schedules in Real-Time will be governed by the CAISO Tariff.

The CAISO shall have the authority to coordinate and approve Generation Outage schedules for the Generating Unit(s) listed in a Net Scheduled PGA, in accordance with the provisions of Section 9.

**4.6.3.5 [Not Used]**

### 4.6.4 Identification of Generating Units

Each Participating Generator shall provide data identifying each of its Generating Units and such information regarding the capacity and the operating characteristics of the Generating Unit as may be reasonably requested from time to time by the CAISO. Each Participating Generator shall provide information on its governor setting and certify that it has not inhibited the real power response of any Generating Unit by any means that would override the governor response except as necessary to address physical operational constraints for reasons that include ambient temperature limitations, outages of mechanical equipment or regulatory considerations. In the event there is a need to inhibit the real power response of any Generating Unit, the Participating Generators shall provide a written description of this limitation with its certification. All information provided to the CAISO regarding the operational and technical constraints in the Master File must be an accurate reflection of the design capabilities of the resources and its constituent equipment when operating at maximum sustainable performance over Minimum Run Time, recognizing that resource performance may degrade over time. Information registered in the Master File by a Scheduling Coordinator must also conform to any additional definitional requirements in Appendix A as may exist as to that information. A Scheduling Coordinator may not submit a Bid for a Generating Unit or offer to provide any other service in the CAISO Markets if that Bid or offer could not be delivered feasibly based on the operational and technical constraints for that Generating Unit registered in the Master File. All information registered in the Master File shall be consistent with the offers and services provided by the resources in the CAISO Markets. The Pump Ramping Conversion Factor is configurable and need not reflect a resource’s design capabilities.

### 4.6.5 NERC and WECC Requirements

**4.6.5.1 Participating Generator Performance Standard**

Participating Generators shall, in relation to each of their Generating Units, meet all Applicable Reliability Criteria, including any standards regarding governor response capabilities, use of power system stabilizers, voltage control capabilities and hourly Energy delivery.

Participating Generators with governor controls that are synchronized to the CAISO Controlled Grid must respond immediately and automatically outside a deadband in proportion to frequency deviations through the action of a governor to help restore frequency to the scheduled value. Participating Generators shall set the governor droop for each Generating Unit with governor controls no higher than 4 percent droop for combustion turbines and 5 percent droop for other technology types; with a deadband no larger than +/- 0.036 Hz. Participating Generators will not inhibit the real power response of their Generating Units with governor controls by any means that would override the governor response except as necessary to address physical operational constraints for reasons that include ambient temperature limitations, outages of mechanical equipment or regulatory considerations.  For each Generating Unit with governor controls, Participating Generators shall coordinate all plant control systems, locally or remotely controlled, so that they include frequency bias to ensure that each Generating Unit can respond immediately and automatically in proportion to frequency deviations to help restore frequency to the scheduled value. Unless otherwise agreed by the CAISO, a Generating Unit must be capable of operating at capacity registered in the CAISO Controlled Grid interconnection data, and shall follow the voltage schedules issued by the PTO or, from time to time, the CAISO.

**4.6.5.2 [Not Used]**

**4.6.5.3 [Not Used]**

### 4.6.6 Forced Outages

Procedures equivalent to those set out in Section 9.3 shall apply to all Participating Generators in relation to Forced Outages.

### 4.6.7 Recordkeeping; Information Sharing

**4.6.7.1 Requirements for Maintaining Records**

Participating Generators shall provide to the CAISO such information and maintain such records as are reasonably required by the CAISO to plan the efficient use and maintain the reliability of the CAISO Controlled Grid.

**4.6.7.2 Providing Information to Generators**

The CAISO shall provide to any Participating Generator, upon its request, copies of any operational assessments, studies or reports prepared by or for the CAISO (unless such assessments studies or reports are subject to confidentiality rights or any rule of law that prohibits disclosure) concerning the operations of such Participating Generator’s Generating Units, including, but not limited to, reports on major Generation Outages, Available Transfer Capability, and Congestion.

**4.6.7.3 Preparation of Reports on Major Incidents**

In preparing any report on a major incident the CAISO shall have due regard to the views of any Participating Generator involved or materially affected by such incident.

### 4.6.8 Sharing Information on Reliability of CAISO Controlled Grid

The CAISO and each Participating Generator shall have the obligation to inform each other, as promptly as possible, of any circumstance of which it becomes aware (including, but not limited to, abnormal temperatures, storms, floods, earthquakes, and equipment depletions and malfunctions and deviations from the Registered Data and operating characteristics) that is reasonably likely to threaten the reliability of the CAISO Controlled Grid or the integrity of the Participating Generator’s facilities. The CAISO and each Participating Generator shall also inform the other as promptly as possible of any incident of which it becomes aware (including, but not limited to, equipment Outages, over-loads or alarms) which, in the case of a Participating Generator, is reasonably likely to threaten the reliability of the CAISO Controlled Grid or, in the case of the CAISO, is reasonably likely to adversely affect the Participating Generator's facilities. Such information shall be provided in a form and content which is reasonable in all the circumstances and sufficient to provide timely warning to the other party of the potential impact.

### 4.6.9 Access Right

A Participating Generator shall, at the request of the CAISO and upon reasonable notice, provide access to its facilities and records (including those relating to communications, telemetry and direct control requirements) as necessary to permit the CAISO or a CAISO approved meter inspector to perform such testing as is necessary (i) to test the accuracy of any meters upon which the Participating Generator’s compensation is based, or performance is measured, (ii) to test the Participating Generator’s compliance with any performance standards pursuant to Section 4.6.5, or (iii) to obtain information relative to a Forced Outage, or (iv) for Participating Intermittent Resources, to ensure compliance with provisions relating to the Participating Intermittent Resource Export Fee.

### 4.6.10 RMTMax for CHP Resources

**4.6.10.1 Initial Determination**

Each Generating Unit that provides Regulatory Must-Take Generation from a CHP Resource must establish an RMTMax, which is determined as follows:

(a) If the Generating Unit’s Scheduling Coordinator is a UDC or MSS and there is a power purchase agreement between the Generating Unit’s owner or operator and its Scheduling Coordinator, by agreement of the two entities, or if not, by agreement of the Generating Unit’s owner or operator and the CAISO, subject to subsection (d) below.

(b) In the event agreement cannot be reached or there is insufficient evidence of any agreement, by affidavit of an independent California-licensed certified engineer based on the engineer’s assessment of the annual and seasonal requirements of the host and the resulting electrical output. Unless otherwise agreed upon, the cost of the engineer will be evenly shared by the Generating Unit’s owner or operator and its Scheduling Coordinator if the Scheduling Coordinator is a UDC or MSS and there is a power purchase agreement between the Generating Unit’s owner or operator and the Scheduling Coordinator, or paid entirely by the Generating Unit’s owner or operator, if the Scheduling Coordinator is not a UDC or MSS.

(c) Based on an agreement between the Generating Unit owner or operator and the Scheduling Coordinator, if it is a UDC or MSS and there is a power purchase agreement between the Generating Unit’s owner or operator and the Scheduling Coordinator, or, otherwise, between the Generating Unit owner or operator and the CAISO, two daily RMTMax values may be established, one for off-peak and one for on-peak, as those terms are defined by NERC.

(d) RMTMax may not be established at a level that will conflict with the terms and conditions of a power purchase agreement negotiated by the Generating Unit owner or operator and the UDC or MSS.

**4.6.10.2 Redetermination**

The RMTMax must be reestablished on an annual basis using the methodologies described in section 4.6.10.1. It may be reestablished more frequently than once a year subject to the Master File change process if agreed by the Generating Unit’s owner or operator and its Scheduling Coordinator, if the Scheduling Coordinator is a UDC or MSS, or by agreement of the Generating Unit’s owner or operator and the CAISO.

**4.6.10.3 Usage Profile**

As part of the initial and annual recertification process, the Generating Unit owner or operator must provide the CAISO and its Scheduling Coordinator, if the Scheduling Coordinator is a UDC or MSS, with an annual non-binding indicative Regulatory Must-Take Generation usage profile.

### 4.6.11 Storage Operating Characteristics

Pursuant to Section 4.6.4, a Scheduling Coordinator for a storage resource participating as a Non-Generator Resource or Pumped-Storage Hydro Unit must submit to the CAISO the operational and technical constraints to the Master File representing an accurate reflection of the resource’s design capabilities and its constituent equipment when operating at maximum sustainable performance over Minimum Run Time, recognizing that resource performance may degrade over time. Non-Generator Resources, Hybrid Resources, and Pumped-Storage Hydro Units may include among their Master File parameters the constraints listed in Section 27.9 to the extent they comply with this Section.

## 4.7 Relationship Between CAISO and Participating Loads

The CAISO shall only accept Bids for Supply of Energy, Imbalance Reserves, Reliability Capacity, or Ancillary Services or Submissions to Self-Provide Ancillary Services from Loads if such Loads are those of a Participating Load that has entered into a Participating Load Agreement with the CAISO and which meet standards adopted by the CAISO and published on the CAISO Website. The CAISO shall not accept submitted Bids for Supply of Energy, Imbalance Reserves, Reliability Capacity, or Ancillary Services from a Participating Load other than through a Scheduling Coordinator. The CAISO shall not accept Bids from Scheduling Coordinators for Participating Loads using the Non-Generator Resource model unless the resource owner or operator undertakes in writing, by entering into a Participating Load Agreement, to comply with all applicable provisions of this CAISO Tariff as they may be amended from time to time.

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## 4.9 Metered Subsystems

### 4.9.1 General Nature of Relationship Between CAISO and MSS

**4.9.1.1** An entity that is determined by the CAISO to qualify as a Metered Subsystem and that undertakes in writing, by entering into a Metered Subsystem Agreement with the CAISO, to comply with all applicable provisions of the CAISO Tariff as specified in that MSS Agreement as they may be amended from time to time, including, without limitation, the applicable provisions of this Section 4.9, shall be considered an MSS Operator and shall have the rights and obligations set forth in this Section 4.9. The CAISO shall not be obligated to accept Bids that would require Energy to be transmitted to or from a Metered Subsystem unless the MSS Agreement of the MSS Operator of the Metered Subsystem has become effective.

### 4.9.2 Coordination of Operations

Each MSS Operator shall operate its MSS at all times in accordance with Good Utility Practice and Applicable Reliability Criteria, including WECC and NERC criteria, and in a manner which ensures safe and reliable operation. All information pertaining to the physical state or operation, maintenance and failure of the MSS affecting the operation of the CAISO Balancing Authority Area that is made available to the CAISO by the MSS Operator shall also be made available to Scheduling Coordinators, provided that the CAISO shall provide reasonable notice to the MSS Operator.  The CAISO shall not be required to make information available to the MSS Operator other than information that is made available to Scheduling Coordinators.

### 4.9.3 Coordinating Maintenance Outages of MSS Facilities

Each MSS Operator shall make appropriate arrangements to coordinate Outages of Generating Units. Each MSS Operator shall make appropriate arrangements to coordinate Outages of transmission facilities forming part of its MSS that will have an effect, or are reasonably likely to have an effect, on any interconnection between the MSS and the system of a Participating TO, prior to the submission by that Participating TO of its Maintenance Outage requirements under Section 9.3. The CAISO will coordinate Outages of other Participating TOs transmission facilities that may affect the MSS.

### 4.9.4 MSS Operator Responsibilities

The MSS Operator’s MSS Agreement with the CAISO shall obligate the MSS Operator to comply with all provisions of the CAISO Tariff, as amended from time to time, applicable to the UDCs, including, without limitation, the applicable provisions of Section 4.4 and Section 7.7. In addition, recognizing the CAISO’s responsibility to promote the efficient use and reliable operation of the CAISO Controlled Grid and the CAISO Balancing Authority Area consistent with the Applicable Reliability Criteria, each MSS Operator shall:

**4.9.4.1** operate and maintain its facilities, in accordance with applicable safety and reliability standards, regulatory requirements, applicable operating guidelines, applicable rates, tariffs, statutes and regulations governing their provision of service to their End-Use Customers and Good Utility Practice so as to avoid any material adverse impact on the CAISO Controlled Grid, it being understood that, if the MSS Operator does not so operate and maintain its facilities and the CAISO concludes, after notice is provided to the MSS Operator, that such failure impairs or threatens to impair the reliability of the CAISO Controlled Grid, the CAISO may suspend MSS status, in accordance with this Section 4.9, until the MSS Operator demonstrates the ability and willingness to so operate and maintain its facilities;

**4.9.4.2** provide the CAISO each year with a schedule of upcoming maintenance of facilities forming part of the MSS that will affect, or is reasonably likely to affect, the CAISO Controlled Grid in accordance with Section 9.3.6;

**4.9.4.3** coordinate with the CAISO, Participating TOs, and Generators to ensure that the CAISO Controlled Grid Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with the protective systems of the MSS, Participating TOs, and Generators, and notify the CAISO as soon as is reasonably possible of any condition that it becomes aware of that may compromise the CAISO Controlled Grid Critical Protective Systems;

**4.9.4.4** be responsible for any Reliability Must-Run Generation and Voltage Support required for reliability of the MSS, including the responsibility for any costs of such Reliability Must-Run Generation, and Voltage Support and may satisfy this requirement through Generating Units owned by the MSS Operator or under contract to the MSS Operator; and

**4.9.4.5** [Not Used]

**4.9.4.6** be responsible for Congestion Management and transmission line Outages within or at the boundary of the MSS, and all associated costs of actions the MSS Operator has to take to resolve such Congestion internal to the MSS and not be responsible for Congestion Management elsewhere, except to the extent that a Scheduling Coordinator is delivering Energy, Imbalance Reserves, Reliability Capacity, or Ancillary Services to or from the MSS. An MSS Operator must notify and communicate with the CAISO regarding transmission line Outages to the extent such Outages impact the CAISO Controlled Grid.

### 4.9.5 Scheduling by or on Behalf of a MSS Operator

All Bids, including but not limited to Self-Schedules, submitted on behalf of an MSS Operator for the delivery of Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services to Loads connected to the MSS and for the delivery of Energy and Ancillary Services from Generating Units forming part of the MSS or System Units shall be submitted by a Scheduling Coordinator that complies with all applicable provisions of the CAISO Tariff, which Scheduling Coordinator may be the MSS Operator, provided that the MSS Operator complies with all applicable requirements for Scheduling Coordinators. A Scheduling Coordinator shall separately identify Bids that it submits on behalf of an MSS Operator.

**4.9.5.1** Without limiting the foregoing, the Scheduling Coordinator for the MSS must submit gross generation information for the System Unit, Generating Unit, and information regarding imports, exports and Gross Loads to the CAISO in the format and in accordance with the timelines applicable to other Scheduling Coordinators.

**4.9.5.2** The Scheduling Coordinator for the MSS will designate, in discrete quantities and with prices for Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services: (1) Bids in the Day-Ahead Market and Real-Time Market (including Bids for internal Generation and internal Demand within the MSS), (2) Submissions to Self-Provide Ancillary Services or Bids for Regulation, Spinning Reserve, and Non-Spinning Reserve, capacity and associated Bid for Energy, or (3) any feasible combination thereof.

**4.9.5.3 MSS Demand Forecast**

The Scheduling Coordinator for the MSS shall provide CAISO with Demand forecasts of the MSS.  To the extent that the Scheduling Coordinator does not provide requisite Demand Forecast for the MSS it represents, the CAISO shall produce a Demand Forecast for each MSS Load Take-Out Point.

### 4.9.6 System Emergencies

**4.9.6.1** The CAISO has authority to suspend MSS control and direct, via communications with the MSS Operator, the operation of Generating Units within the MSS, including Generating Units that may comprise a System Unit, if such control is necessary to maintain CAISO Controlled Grid reliability.

**4.9.6.2** If Load Shedding is required to manage System Emergencies, the CAISO will determine the amount and location of Load to be reduced pursuant to Section 7.7.5.1 and 7.7.5.2. Each MSS Operator shall be responsible for notifying its customers and Generators connected to its system of curtailments and service interruption.

**4.9.6.3 System Emergency Reports: MSS Obligations**

**4.9.6.3.1** Each MSS Operator shall maintain all appropriate records pertaining to a System Emergency.

**4.9.6.3.2** Each MSS Operator shall cooperate with the CAISO in preparation of an Outage in review pursuant to Section 7.7.13.

### 4.9.7 Coordination of Expansion or Modification to MSS Facilities

Each MSS Operator and any Participating TO with which its system is interconnected, if applicable, shall coordinate in the planning and implementation of any expansion or modifications of a MSS’s or Participating TO’s system that will affect their transmission interconnection, the CAISO Controlled Grid or the transmission services to be required by the MSS Operator. The MSS Operator and any Participating TO with which the MSS is interconnected shall be responsible for coordinating with the CAISO.

### 4.9.8 Ancillary Services Obligations for MSS

**4.9.8.1** Ancillary Services Obligations will be allocated to the Scheduling Coordinator bidding or scheduling Load within a MSS in accordance with the CAISO Tariff. The CAISO shall have the right to call upon the Self-Provided Ancillary Service of a Scheduling Coordinator for an MSS or procured by the CAISO from such Scheduling Coordinator in accordance with the CAISO Tariff. The Scheduling Coordinator representing the MSS Operator may provide a Submission to Self-Provide an Ancillary Service or bid (including self-provide) Ancillary Services from a System Unit or from individual Generating Units or Participating Loads, or Proxy Demand Resources in the MSS. Alternatively, the Scheduling Coordinator representing the MSS may purchase Ancillary Services from the CAISO or third parties to meet all or part of its Ancillary Services Obligations in accordance with the CAISO Tariff.

**4.9.8.2** If the MSS Operator desires to follow internal Load with a System Unit or Generating Units in the MSS, and also to provide Regulation to the CAISO, the MSS must provide adequate telemetry consistent with the CAISO Tariff and all applicable standards to allow performance in response to CAISO AGC signals to be measured at the interconnection of the MSS to the CAISO Controlled Grid.

### 4.9.9 [Not Used]

### 4.9.10 Information Sharing

**4.9.10.1 System Planning Studies and Forecasts**

The CAISO, the MSS Operator and Participating TOs shall share information such as projected Load growth and system expansions necessary to conduct necessary system planning studies to the extent that these may impact the operation of the CAISO Balancing Authority Area. Each MSS Operator shall provide to the CAISO annually its ten-year forecasts of Demand growth, internal Generation, and expansion of or replacement for any transmission facilities that are part of the MSS that will or may significantly affect any point of interconnection between the MSS and the CAISO Controlled Grid. Such forecasts shall be provided on the date that UDCs are required to submit forecasts to the CAISO under Section 4.4.5.1. Each MSS Operator or each Scheduling Coordinator for an MSS Operator shall also submit weekly and monthly peak Demand Forecasts in accordance with the CAISO’s Business Practice Manuals.

**4.9.10.2 System Surveys and Inspections**

The CAISO and each MSS Operator shall cooperate with each other in performing system surveys and inspections to the extent these relate to the operation of the CAISO Balancing Authority Area.

**4.9.10.3 Reports**

**4.9.10.3.1** The CAISO shall make available to each MSS Operator any public annual reviews or reports regarding performance standards, measurements and incentives relating to the CAISO Controlled Grid and shall also make available, upon reasonable notice, any such reports that the CAISO receives from Participating TOs. Each MSS Operator shall make available to the CAISO any public annual reviews or reports regarding performance standards, measurements and incentives relating to the MSS’s Distribution System to the extent these relate to the operation of the CAISO Controlled Grid.

**4.9.10.3.2** The CAISO and the MSS Operators shall develop an operating procedure to record requests received for Maintenance Outages by the CAISO and the completion of the requested maintenance and turnaround times.

**4.9.10.3.3** Each MSS Operator shall promptly provide such information as the CAISO may reasonably request concerning the MSS Operator’s operation of the MSS to enable the CAISO to meet its responsibility under the CAISO Tariff to conduct reviews and prepare reports following major Outages. Where appropriate, the CAISO will provide appropriate assurances that the confidentiality of commercially sensitive information shall be protected. The CAISO shall have no responsibility to prepare reports on Outages that affect customers on the MSS, unless the Outage also affects customers connected to the system of another entity within the CAISO Balancing Authority Area. The MSS Operator shall be solely responsible for the preparation of any reports required by any governmental entity or the WECC with respect to any Outage that affects solely customers on the MSS.

**4.9.10.3.4 Reliability Information**

Each MSS Operator shall inform the CAISO, and the CAISO shall inform each MSS Operator, in each case as promptly as possible, of any circumstance of which it becomes aware (including, but not limited to, abnormal temperatures, storms, floods, earthquakes, and equipment depletions and malfunctions and deviations from Registered Data and operating characteristics) that is reasonably likely to threaten the reliability of the CAISO Controlled Grid or the integrity of the MSS respectively. Each MSS Operator and the CAISO each shall also inform the other as promptly as possible of any incident of which it becomes aware (including, but not limited to, equipment Outages, over-loads or alarms) which, in the case of the MSS Operator, is reasonably likely to threaten the reliability of the CAISO Controlled Grid, or, in the case of the CAISO, is reasonably likely to adversely affect the MSS. Such information shall be provided in a form and content which is reasonable in all the circumstances, sufficient to provide timely warning to the entity receiving the information of the threat and, in the case of the CAISO, not unduly discriminatory with respect to the CAISO’s provision of similar information to other entities.

**4.9.10.3.5 Forms**

The CAISO shall, in consultation with MSS Operators, jointly develop and, as necessary, revise, any necessary forms and procedures for collection, study, treatment, and transmittal of system data, information, reports and forecasts.

**4.9.10.4** Each MSS Operator shall provide to the CAISO information as provided in Section 36.8.5.2 that enables the CAISO to perform transfers of CRRs to reflect Load Migration in a timely manner as required in Section 36.8.5.

### 4.9.11 Installation of and Rights of Access to MSS Facilities

**4.9.11.1 Installation of Facilities.**

**4.9.11.1.1 Meeting Service Obligations.**

The CAISO and each MSS Operator shall each have the right, if mutually agreed, on reasonable notice to install or to have installed equipment (including metering equipment) or other facilities on the property of the other, to the extent that such installation is necessary for the installing party to meet its service obligations unless to do so would have a negative impact on the reliability of the service provided by the party owning the property.

**4.9.11.1.2 Governing Agreements for Installations.**

The CAISO and the MSS Operator shall enter into agreements governing the installation of equipment or other facilities containing customary and reasonable terms and conditions.

**4.9.11.2 Access to Facilities.**

Each MSS Operator shall grant the CAISO reasonable access to MSS facilities free of charge for purposes of inspection, repair, maintenance, or upgrading of facilities installed by the CAISO on the MSS’s system, provided that the CAISO must provide reasonable advance notice of its intent to access MSS facilities. Such access shall not be provided unless the parties mutually agree to the date, time and purpose of each access. Agreement on the terms of the access shall not be unreasonably withheld.

**4.9.11.3 Access During Emergencies.**

Notwithstanding any provision in this Section 4.9, the CAISO may have access, without giving prior notice, to any MSS Operator’s equipment or other facilities during times of a System Emergency or where access is needed in connection with an audit function.

### 4.9.12 MSS System Unit

**4.9.12.1** A MSS Operator may aggregate one or more Generating Units, Participating Loads, Reliability Demand Response Resources, and/or Proxy Demand Resources as a System Unit. A System Unit must be modeled as an aggregated Generating Unit and must provide a set of Generation Distribution Factors. Except as specifically provided in the MSS Agreement referred to in Section 4.9.1.1, all provisions of the CAISO Tariff applicable to Participating Generators and to Generating Units (and, if the System Unit includes a Load, to Participating Loads, Reliability Demand Response Resources, and Proxy Demand Resources), shall apply fully to the System Unit and the Generating Units and/or Loads included in it.  The MSS Operator’s MSS Agreement with the CAISO in accordance with Section 4.9.1.1 shall obligate the MSS Operator to comply with all provisions of the CAISO Tariff, as amended from time to time, applicable to the System Unit, including, without limitation, the applicable provisions of Sections 4.6.1 and 7.7. In accordance with Section 7.6.1, the CAISO will obtain control over the System Unit, not the individual Generating Unit, except for Regulation, to comply with Section 4.6.

**4.9.12.2** Without limiting the generality of Section 4.9.12.1, a MSS Operator that owns or has an entitlement to a System Unit:

**4.9.12.2.1** is required to have a direct communication link to the CAISO’s EMS satisfying the requirements applicable to Generating Units owned by Participating Generators, Participating Loads or Proxy Demand Resources, as applicable, for the System Unit and the individual resources that make up the System Unit;

**4.9.12.2.2** shall provide resource-specific information regarding the Generating Units and Loads comprising the System Unit to the CAISO through telemetry to the CAISO’s EMS;

**4.9.12.2.3** shall obtain CAISO certification of the System Unit’s Ancillary Service capabilities in accordance with Sections 8.4 and 8.9 before the Scheduling Coordinator representing the MSS may self-provide its Ancillary Service Obligations or bid into the CAISO Markets from that System Unit;

**4.9.12.2.4** shall provide the CAISO with control over the AGC of the System Unit, if the System Unit is supplying Regulation to the CAISO or is designated to self-provide Regulation;

**4.9.12.2.5** shall install CAISO certified meters on each individual resource or facility that is aggregated to a System Unit; and

**4.9.12.2.6** shall provide, through the Scheduling Coordinator representing the MSS Operator, Settlement Quality Meter Data for the System Unit’s Proxy Demand Resources and Reliability Demand Response Resources.

**4.9.12.3** Subject to Section 4.9.12.4, the CAISO shall have the authority to exercise control over the System Unit to the same extent that it may exercise control pursuant to the CAISO Tariff over any other Participating Generator, Generating Unit or, if applicable, Participating Load, Reliability Demand Response Resource, or Proxy Demand Resource, but the CAISO shall not have the authority to direct the MSS Operator to adjust the operation of the individual resources that make up the System Unit to comply with directives issued with respect to the System Unit.

**4.9.12.4** When and to the extent that Energy from a System Unit is self-scheduled to provide for the needs of Loads within the MSS and is not being bid to the CAISO Markets, the CAISO shall have the authority to dispatch the System Unit only to avert or respond to a circumstance described in the third sentence of Section 7.6.1 or, pursuant to Section 7.7.2.3, to a System Emergency.

### 4.9.13 MSS Elections and Participation in CAISO Markets

MSS Operators must make an election or choice on three (3) issues that govern the manner in which the MSS participates in the CAISO Markets. The MSS Operator must choose either: (i) net Settlements or gross Settlements, (ii) to Load follow or not Load follow with its generating resources, and (iii) whether or not to charge the CAISO for their Emissions Costs as provided in Section 11.7.4. The MSS Operator shall make annual elections regarding these three (3) sets of options pursuant to the timeline specified for such elections in the Business Practice Manuals.

The MSS Operator’s prior year election will be the default if the MSS Operator does not make a timely election, unless the MSS Operator has been found to have violated Load following requirements and is no longer eligible for making such elections.  If the MSS Operator fails to elect net Settlement as specified in Section 11.2.3.2, the default mechanism for all MSS Settlements shall be gross Settlement as specified in Section 11.2.3.1.

The Load following and net or gross Settlement elections of an MSS Operator change certain aspects of, but do not preclude, the participation of the MSS in the CAISO Markets. An MSS Operator may: (i) bid to supply Energy to, or purchase Energy from, the CAISO Markets, (ii) bid to provide available capacity in RUC, and (iii) bid or make a Submission to Self-Provide an Ancillary Service from a System Unit or from individual Generating Units, Participating Loads or Proxy Demand Resources within the MSS. An MSS Operator also may purchase Ancillary Services from CAISO or third parties to meet its Ancillary Service Obligations under the CAISO Tariff.

**4.9.13.1 Gross or Net Settlement**

An MSS Operator has the option to settle with the CAISO on either a gross basis or a net basis for its Load and generating resources. This election shall be made annually for a period consistent with annual CRR Allocation. If the MSS Operator elects net Settlement, then CRRs would be allocated on MSS net Load and the MSS may choose the MSS LAP as its CRR Sink in the first tiers of CRR Allocation. If the MSS Operator elects gross Settlement, then CRRs would be allocated on a gross Load basis and the MSS may not choose the MSS LAPs as its CRR Sink in the first tiers of CRR Allocation.

**4.9.13.2 Load-Following or Non Load-Following Election**

The MSS Operator has the option to elect to operate a System Unit or Generating Units in the MSS to follow its Load, provided that: (a) the Scheduling Coordinator for the MSS Operator shall remain responsible for purchases of Energy in accordance with the CAISO Tariff if the MSS Operator does not operate its System Unit or Generating Units and bid or schedule imports into the MSS, to match the metered Demand in the MSS and exports from the MSS; and (b) if the deviation between Generation and imports into the MSS and metered Demand and exports from the MSS exceeds the MSS Deviation Band, then the Scheduling Coordinator for the MSS Operator shall pay the additional amounts specified in Section 11.7. If an MSS Operator elects Load-following and net Settlements, all generating resources within the MSS must be designated as Load-following resources. If an MSS Operator elects Load-following and gross Settlements, generating resources within the MSS can be designated as either Load-following or non-Load-following resources. Consistent with these requirements, the MSS Operator may also modify the designation of generating resources within the MSS within the timing requirements specified for such Master File changes as described in the Business Practice Manuals.

If the MSS Operator has elected gross Settlement and is a Load-following MSS: (i) it must designate in the Master File which of its generating resources are Load-following resources, (ii) it must complying with the additional bidding requirements in Section 30.5.2.5, and (iii) the generation resources designated as Load-following resources cannot set Real-Time prices. However, Load-following resources will be eligible to receive Bid Cost Recovery to ensure that the price paid for Energy dispatched by the CAISO is not less than the MSS Operator’s accepted Bid price. Bid Cost Recovery for a Load-following MSS resource is only applicable to generation capacity provided to the CAISO Markets by that MSS resource and is not applicable for the generating capacity that is designated or used by an MSS Operator to follow its own Load.

An MSS Operator may designate RMR Resources as Load-following. Load-following RMR Resources must be available to the CAISO for Dispatch up to the RMR Contract Capacity specified in the RMR Contract. Energy shall be accounted for as a delivery from the MSS to the CAISO for the purposes of determining if the MSS Operator followed its metered Demand and exports from the MSS as described in this Section 4.9.13.2 except that Energy from an RMR Resources in a Day-Ahead Schedule can be used for Load-following to satisfy Day-Ahead scheduled Demand like any other non-RMR Resource Load-following resource. If no RMR Dispatch Notice is received for a Load-following RMR Resource, such Load-following RMR Resource may participate in the CAISO Markets as any other non-RMR Load-following resource subject to Section 30.5.2.5.

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## 4.12 Relationship of CAISO and Resource-Specific System Resources

The CAISO shall not accept Bids for any Resource-Specific System Resource otherwise than through a Scheduling Coordinator. The CAISO shall further not be obligated to provide Bid Cost Recovery to any Resource-Specific System Resource unless the relevant Resource-Specific System Resource owner undertakes in writing, by entering into a Resource-Specific System Resource Agreement, to comply with all applicable provisions of this CAISO Tariff as they may be amended from time to time, including, without limitation, the applicable provisions of this Section 4.12. Except as otherwise provided in this Section 4.12, Resource-Specific System Resources shall have the same rights and obligations as other System Resources, including the ability to have Bids submitted for either full or partial output from the RSSR, provided that a Bid must be for at least the Minimum Load of the resource in order to be eligible for Bid Cost Recovery.

### 4.12.1 General Responsibilities

**4.12.1.1 Operate Pursuant to Relevant Provisions of CAISO Tariff**

Resource-Specific System Resource owners shall operate, or cause their facilities to be operated, in accordance with the relevant provisions of this CAISO Tariff, including but not limited to the following.

(i) A Resource-Specific System Resource shall only be eligible for Bid Cost Recovery if the Resource-Specific System Resource has complied with a Start-Up Instruction or Dispatch Instruction issued by the CAISO as specified in Section 11.8.

(ii) In order to be eligible for Bid Cost Recovery, a Resource-Specific System Resource owner shall ensure that its Scheduling Coordinator makes an election for Default Start-Up Bids and Default Minimum Load Bids pursuant to Sections 30.4 and 30.5.2.4.

(iii) A Resource-Specific System Resource owner shall ensure that any Ancillary Services Bids submitted by its Scheduling Coordinator are submitted in accordance with Section 30.5.2.6.

(iv) Owners of Dynamic Resource-Specific System Resources that are Resource Adequacy Resources shall comply with additional availability requirements to the extent required by Section 40.6.5.1.

(v) Each Resource-Specific System Resource owner shall immediately inform the CAISO, through its respective Scheduling Coordinator and using the CAISO’s outage management system as described in Section 9, of any change or potential change in the current status of any Resource-Specific System Resource that may affect a submitted Bid. This will include, but not be limited to, any change in status of equipment that could affect the maximum output of a Resource-Specific System Resource, the Minimum Load of a Resource-Specific System Resource, or the ability of a Resource-Specific System Resource to provide Ancillary Services in accordance with its Bid.

(vi) In the event that a Resource-Specific System Resource owner cannot meet its schedule as specified in the Day-Ahead Schedule, or comply with a Dispatch Instruction, whether due to a Resource-Specific System Resource trip or the loss of a piece of equipment causing a reduction in capacity or output, the Resource-Specific System Resource owner shall notify the CAISO, through its Scheduling Coordinator, at once. If a Resource-Specific System Resource owner will not be able to meet a time commitment or requires the cancellation of a Resource-Specific System Resource Start-Up, it shall notify the CAISO, through its Scheduling Coordinator, at once.

**4.12.1.2 Operate Pursuant to Relevant Operating Procedures**

Resource-Specific System Resource owners shall operate, or cause their Resource-Specific System Resources and associated facilities to be operated, in accordance with the relevant Operating Procedures and Business Practice Manuals established by the CAISO.

### 4.12.2 Identification of Resource-Specific System Resources

Each Resource-Specific System Resource owner shall provide data identifying each of its Resource-Specific System Resources and such information regarding the capacity and the operating characteristics of the Resource-Specific System Resource as may be reasonably requested from time to time by the CAISO. All information provided to the CAISO regarding the operational and technical constraints in the Master File must be an accurate reflection of the design capabilities of the resources and its constituent equipment when operating at maximum sustainable performance over Minimum Run Time, recognizing that resource performance may degrade over time. Information registered in the Master File by a Scheduling Coordinator must also conform to any additional definitional requirements in Appendix A as may exist as to that information.Pursuant to Sections 8.9 and 8.10, the CAISO may verify, inspect and test the capacity and operating characteristics of the resource provided to the CAISO.

### 4.12.3 Telemetry Data to Demonstrate Compliance

The Resource-Specific System Resource owner shall provide SCADA data by telemetry to the CAISO EMS at the Resource-Specific System Resource owner’s expense in order to demonstrate compliance with CAISO Start-Up Instructions in order to be eligible for BCR. Telemetry data from Dynamic Resource-Specific System Resources shall be provided in accordance with the requirements of the CAISO’s Dynamic Scheduling Protocol in Appendix M. For Non-Dynamic Resource-Specific System Resources, the Resource-Specific System Resource owner shall have the option of providing the required telemetry data by transmittal directly to the CAISO EMS in accordance with the CAISO’s standards for direct telemetry or by means of transmittal to the CAISO EMS through the EMS of its Host Balancing Authority Area by use of the inter-control center communications protocol (ICCP).

### 4.12.4 Recordkeeping

Resource-Specific System Resource owners shall provide to the CAISO such information and maintain such records as are reasonably required by the CAISO to implement the provisions of the CAISO Tariff applicable to Resource-Specific System Resources.

### 4.12.5 Access Rights

A Resource-Specific System Resource owner shall, at the request of the CAISO and upon reasonable notice, provide access to its facilities and records (including those relating to communications and telemetry) as necessary to permit the CAISO to perform such testing as is necessary to test the accuracy of any telemetry equipment upon which the Resource-Specific System Resource owner’s performance is measured.

## 4.13 DRPs, RDRRs, and PDRs

### 4.13.1 Relationship Between CAISO and DRPs

Consistent with Section 30.6, the CAISO shall only accept Bids from Reliability Demand Response Resources and Proxy Demand Resources if such Reliability Demand Response Resources or Proxy Demand Resources are represented by a Demand Response Provider that has entered into a Demand Response Provider Agreement with the CAISO, has accurately provided the information required in the Demand Response System, has satisfied all Reliability Demand Response Resource or Proxy Demand Resource registration requirements, and has met standards adopted by the CAISO and published on the CAISO Website.  Reliability Demand Response Resources and Proxy Demand Resources may not participate in a Distributed Energy Resource Aggregation. The CAISO shall not accept Bids from a Demand Response Provider other than through a Scheduling Coordinator, which Scheduling Coordinator may be the Demand Response Provider itself or another entity. Proxy Demand Response Resources providing Ancillary Services must submit Meter Data for the interval preceding, during, and following the Trading Interval(s) in which they were awarded Ancillary Services for the purposes of determining settlement pursuant to Section 8.10.8.

### 4.13.2 Applicable Requirements for RDRRs, PDRs and DRPs

A single Demand Response Provider must represent each Reliability Demand Response Resource or Proxy Demand Resource and may represent more than one (1) Reliability Demand Response Resource or Proxy Demand Resource. Each Reliability Demand Response Resource or Proxy Demand Resource that is not within a MSS must be associated with a single Utility Distribution Company. A Demand Response Provider may be, but is not required to be, a Load Serving Entity or a Utility Distribution Company. Each Reliability Demand Response Resource or Proxy Demand Resource is required to be located in a single Sub-LAP. All underlying locations of a Reliability Demand Response Resource or Proxy Demand Resource must be located in a single Sub-LAP. Each Demand Response Provider is required to satisfy registration requirements and to provide information to allow the CAISO to establish performance evaluation methodologies in accordance with Section 4.13.4 and the applicable Business Practice Manuals. Registration of a location for participation in Reliability Demand Response Resources or Proxy Demand Resources requires the approval of the CAISO resulting from its registration process. As part of the submitted registration process, both the appropriately Demand Response Provider designated Load Serving Entity and Utility Distribution Company will have an opportunity to review the location detail and provide comments with regard to its accuracy. Disputes regarding the acceptances or rejections of a registration of a location shall be undertaken with the applicable Local Regulatory Authority and shall not be arbitrated or in any way resolved through a CAISO dispute resolution mechanism or process. A location cannot be registered to both a Reliability Demand Response Resource and a Proxy Demand Resource for the same Trading Day.

### 4.13.3 Identification of RDRRs and PDRs

Each Demand Response Provider shall provide data, as described in the Business Practice Manual, identifying each of its Reliability Demand Response Resources or Proxy Demand Resources and such information regarding the capacity and the operating characteristics of the Reliability Demand Response Resource or Proxy Demand Resource as may be reasonably requested from time to time by the CAISO. All information provided to the CAISO regarding the operational and technical constraints in the Master File shall be accurate and actually based on physical characteristics of the resources. For Proxy Demand Resources and Reliability Demand Response Providers whose maximum Load curtailment is 1 MW or more, Demand Response Providers may elect to specify in the Master File the maximum number of Operating Hours in which the CAISO could commit or dispatch the Proxy Demand Resources or Reliability Demand Response Resources in the Operating Day. Demand Response Providers for Proxy Demand Resources and Reliability Demand Response Resources may elect to specify in the Master File how the Proxy Demand Resource and Reliability Demand Response Resources will bid and be dispatched in the Real-Time Market: in (i) Hourly Blocks, (ii) fifteen (15) minute intervals, or (iii) five (5) minute intervals. Proxy Demand Resources using the load-shift methodology described in Section 4.13.4.7 may elect to bid and be dispatched in the Real-Time Market in fifteen (15) minute intervals or five (5) minute intervals. If Demand Response Providers do not submit an election in the Master File, the CAISO will set five (5) minute intervals as the default.

### 4.13.4 Performance Evaluation Methodologies for PDRs and RDRRs

The following methodologies may be utilized to calculate Customer Load Baselines and Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources. Proxy Demand Resources and Reliability Demand Response Resources consisting of residential End Users may elect to use the ten-in-ten methodology, metering generator output methodology, control group methodology, five-in-ten methodology, or weather matching methodology. Proxy Demand Resources and Reliability Demand Response Resources consisting of non-residential End Users may elect to use the ten-in-ten methodology, metering generator output methodology, control group methodology, or weather matching methodology. Proxy Demand Resources with behind-the-meter energy storage also may elect to use the load-shift methodology. If an EVSE elects to participate as a Proxy Demand Resource and use a different methodology than its co-located Load, it must adhere to Section 4.13.4.6. Proxy Demand Resources providing Ancillary Services must submit Meter Data for the intervals immediately preceding, during, and following the Trading Interval(s) in which the Proxy Demand Resources were awarded Ancillary Services. As specified in the Business Practice Manual, the CAISO will retain authority to calculate or correct Customer Load Baselines and Demand Response Energy Measurements for those resources that used the CAISO’s Demand Response System, until all relevant metering, settlement, and correction windows have lapsed since the CAISO retired its ability to calculate on behalf of Scheduling Coordinators in the Demand Response System.

**4.13.4.1 Ten-in-Ten Load Baseline Methodology**

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the ten-in-ten methodology as follows:

(a) Meter Data will be collected for the Proxy Demand Resource or Reliability Demand Response Resource for calendar days preceding the Trading Day on which the Demand Response Event occurred. Where the Proxy Demand Resource or Reliability Demand Response Resource uses behind-the-meter generation to offset Demand, the Proxy Demand Resource or Reliability Demand Response Resource may elect to provide, at all times, Meter Data reflecting the total gross consumption, independent of any offsetting Energy produced by behind-the-meter generation. The calendar days for which the Meter Data will be collected will be determined by working sequentially backwards from the Trading Day under examination up to a maximum of forty-five (45) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, except as discussed below. The collection of Meter Data for this purpose stops upon reaching the target number of calendar days, which is ten (10) calendar days if the Trading Day is a business day or four (4) calendar days if the Trading Day is a non-business day. If these targets cannot be met, a minimum of five (5) calendar days if the Trading Day is a business day or a minimum of four (4) calendar days if the Trading Day is a non-business day must be collected. If these targets cannot be met, Meter Data will be collected for the calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, and for which the amount of totalized load was highest during the hours when the Demand Response Services were provided in the forty-five (45) calendar days prior to the Trading Day.

(b) The Scheduling Coordinator will be responsible for calculating the simple hourly average of the collected Meter Data to determine a baseline amount of Energy provided by the Proxy Demand Resource or Reliability Demand Response Resource.

(c) Unless otherwise requested by the Demand Response Provider and approved by the CAISO, the Scheduling Coordinator will be responsible for multiplying the amount calculated pursuant to Section 4.13.4.1(b) by a percentage equal to the ratio of (i) the average load of the Proxy Demand Resource or Reliability Demand Response Resource during the second, third, and fourth hours preceding the hour of the Trading Day on which the Proxy Demand Resource or Reliability Demand Response Resource provided the Demand Response Services during the Demand Response Event to (ii) the average load of the Proxy Demand Resource or Reliability Demand Response Resource during the same second, third, and fourth hours of the calendar days for which Meter Data has been collected pursuant to Section 4.13.4.1(a). To provide a maximum adjustment factor of twenty (20) percent, the adjusted percentage can have a maximum value of one hundred-twenty (120) percent and a minimum value of eighty (80) percent.

(d) If the Proxy Demand Resource or Reliability Demand Response Resource elects to provide Meter Data reflecting the total gross Demand at all times, independent of any offsetting Energy, the offsetting Energy must be metered separate from Load to enable the accurate calculation of total gross consumption.

**4.13.4.2 Metering Generator Output Methodology**

For behind-the-meter generation registered in Proxy Demand Resources or Reliability Demand Response Resources and settling Energy Transactions pursuant to Section 11.6.2, the Generator Output Baseline will be calculated as follows:

(a) Meter Data will be collected for the behind-the-meter generation for the same hour as the Trading Hour on calendar days preceding the Trading Day on which the Demand Response Event occurred for which the Generator Output Baseline is calculated. Meter Data will consist of Energy output of the behind-the-meter generation up to, but not including, output that represent an export of energy from that location. To determine the hours for which the Meter Data will be collected, the calculation will work sequentially backwards from the Trading Day under examination up to a maximum of forty-five (45) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding hours in which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) pursuant to a Bid at or above the net benefits test set forth in Section 30.6.3, or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services pursuant to a Bid at or above the net benefits test set forth in Section 30.6.3, except as discussed below. The calculation will have complete Meter Data for this purpose if and when it is able to collect Meter Data for its target number of hours the same as the Trading Hour, which target number is ten (10) hours if the Trading Day is a business day or four (4) hours if the Trading Day is a non-business day. If it is not possible to collect Meter Data for the target number of hours, the Meter Data will include a minimum of five (5) hours if the Trading Day is a business day or a minimum of four (4) hours if the Trading Day is a non-business day. If it is not possible to collect Meter Data for the minimum number of hours described above, the Generator Output Baseline will be set at zero.

(b) The baseline amount of Energy provided by the behind-the-meter generation will be calculated on the simple hourly average of the collected Meter Data.

(c) In calculating the Generator Output Baseline pursuant to Section 4.13.4.2(a), the Meter Data must be set to zero in any Settlement Interval in which the behind-the-meter generation is charging.

(d) In any Settlement Interval where the behind-the-meter generation is exporting Energy (i.e., where the behind-the-meter generation Energy output exceeds its location Demand), the Meter Data will consist of the Energy output of the behind-the-meter generation up to, but not including, the output greater than its facility Demand that would represent an export of Energy from that location.

**4.13.4.3 Control Group Methodology**

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the control group methodology as follows:

(a) Prior to any Demand Response Event, a randomized control group of End Users that are registered in the Demand Response System but not responding to CAISO dispatch as Proxy Demand Resources or Reliability Demand Response Resources must be submitted to the CAISO. But for any Demand Response Event, the control group must have nearly identical Demand patterns in aggregate as the Proxy Demand Resources or Reliability Demand Response Resources. The control group must be geographically similar to the Proxy Demand Resources or Reliability Demand Response Resources such that they experience the same weather patterns and grid conditions. The control group must consist of 150 distinct End Users or more. Prior to use of the control group baseline methodology, Scheduling Coordinators will be responsible for validating the control group pursuant to Section 4.13.4.3(c).

(b) The control group’s aggregate Demand during the same Trade Date and Trading Hour(s) as the Demand Response Event, divided by the relevant number of End Users, will constitute the Customer Load Baseline.

(c) Scheduling Coordinators are responsible for validating that the control group accurately represents its Proxy Demand Resources or Reliability Demand Response Resources. As described in the Business Practice Manual, to validate the control group, Meter Data of the control group and the Proxy Demand Resources or Reliability Demand Response Resources from the previous seventy-five (75) days must be evaluated, excluding days where the Proxy Demand Resources or Reliability Demand Response Resources provided Demand Response Services or participated in a utility demand response program. Using the most recent days, at least twenty (20) eligible days of Meter Data must be used for validation. From these days, an average of the hourly load profile from 12 p.m. to 9 p.m. must be developed for the Proxy Demand Resources or Reliability Demand Response Resources and the control group by day and by hour. The average hourly Demand of the Proxy Demand Resources or Reliability Demand Response Resources is then regressed against the average hourly Demand of the control group. As described in the Business Practice Manual, the control group must statistically demonstrate (i) lack of bias and (ii) sufficient statistical precision with (iii) sufficient confidence. Control groups that fail these screens may not be used.

(d) For Proxy Demand Resources or Reliability Demand Response Resources whose number of End Users have not changed by more than ten (10) percent in the prior month, the control group must be re-validated every other month. For Proxy Demand Resources or Reliability Demand Response Resources whose number of End Users have changed by more than ten (10) percent in the prior month, control groups must continue to be re-validated monthly.

(e) Control group randomization, equivalence, and validation, and all Demand Response Event calculations are subject to CAISO audit for three (3) years from the date Demand Response Event. All results must be reproducible, including underlying interval data, randomization, validation, bias, confidence, precision, and analysis.

**4.13.4.4 Five-in-Ten Methodology**

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the five-in-ten methodology as follows:

(a) Meter Data for the Proxy Demand Resource or Reliability Demand Response Resource will be collected for calendar days preceding the Trading Day on which the Demand Response Event occurred for the Customer Load Baseline. Where the Proxy Demand Response or Reliability Demand Response Resource may elect to provide, at all times, Meter Data reflecting the total gross consumption, independent of any offsetting Energy produced by behind-the-meter generation. The calendar days for which the Meter Data will be collected will be determined by working sequentially backwards from the Trading Day under examination up to a maximum of forty-five (45) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, except as discussed below. The collection of Meter Data for this purpose stops upon reaching the target number of calendar days, which is ten (10) calendar days if the Trading Day is a business day or five (5) calendar days if the Trading Day is a non-business day. From the target days, the five (5) business days and three (3) non-business days with the highest totalized load during the hours when the Demand Response Services were provided will be used. If these targets cannot be met, the Meter Data will instead be used for the calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services, and for which the amount of totalized load was highest during the hours when the Demand Response Services were provided in the forty-five (45) calendar days prior to the Trading Day.

(b) For business days, the Scheduling Coordinator will be responsible for calculating the simple hourly average of the collected Meter Data to determine a baseline amount of Energy provided by the Proxy Demand Resource or Reliability Demand Response Resource. For non-business days, the Scheduling Coordinator will be responsible for calculating a weighted average of the collected Meter Data to determine a baseline as follows: the day closest to the Demand Response Event receives a weight of fifty (50) percent, the next closest receives a weight of thirty (30) percent, and the furthest receives a weight of twenty (20) percent.

(c) Unless otherwise requested by the Demand Response Provider and approved by the CAISO, the Scheduling Coordinator will be responsible for multiplying the amount calculated pursuant to Section 4.13.4.4(b) by a percentage of the ratio of:

(i) the average Demand of Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from two (2) to four (4) hours following the Trading Intervals on which the Proxy Demand Resource or Reliability Demand Response Resource provided Demand Response Services during the Demand Response Event to

(ii) the average Demand of the Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from (2) to four (4) hours following the Trading Intervals for which Meter Data was collected pursuant to Section 4.13.4.4(a).

To provide maximum adjustment factor of 1.4, the adjusted percentage can have a maximum value of one hundred-forty (140) percent and a minimum value of seventy-one (71) percent.

(d) If the Proxy Demand Resource or Reliability Demand Response Resource elects to provide Meter Data reflecting the total gross Demand at all times, independent of any offsetting Energy, the offsetting Energy must be separated from Load to enable the accurate calculation of total gross consumption.

**4.13.4.5 Weather Matching Methodology**

Scheduling Coordinators will be responsible for calculating the Customer Load Baseline for Proxy Demand Resources or Reliability Demand Response Resources using the weather matching methodology as follows:

1. The Scheduling Coordinator will be responsible for collecting Meter Data for the Proxy Demand Resource or Reliability Demand Response Resource for calendar days preceding the Trading Day on which the Demand Response Event occurred. Where the Proxy Demand Response or Reliability Demand Response Resource uses behind-the-meter generation to offset Demand, the Proxy Demand Resource or Reliability Demand Response Resource may elect to provide, at all times, Meter Data reflecting the total gross consumption, independent of any offsetting Energy produced by behind-the-meter generation. The calendar days for which the Meter Data will be collected will be determined by working sequentially backwards from the Trading Day under examination up to a maximum of ninety (90) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding calendar days on which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC) or the Reliability Demand Response Resource was subject to an Outage as described in the Business Practice Manual or previously provided Demand Response Services. As detailed in the Business Practice Manual, from the ninety (90) calendar days prior to the Trading Day, the four (4) days with the closest daily maximum temperature to the Trading Day will be used to calculate the baseline.

(b) The Scheduling Coordinator will be responsible for calculating the simple hourly average of the collected Meter Data to determine a baseline amount of Energy provided by the Proxy Demand Resource or Reliability Demand Response Resource.

(c) Unless otherwise requested by the Demand Response Provider and approved by the CAISO, the Scheduling Coordinator will be responsible for multiplying the amount calculated pursuant to Section 4.13.4.5(b) by a percentage equal to the ratio of:

(i) the average Demand of the Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from two (2) to four (4) hours following the Trading Intervals on which the Proxy Demand Resource or Reliability Demand Response Resource provided the Demand Response Services during the Demand Response Event to

(ii) the average Demand of the Proxy Demand Resource or Reliability Demand Response Resource during (a) the period from four (4) to two (2) hours preceding the Trading Intervals, and (b) the period from two (2) to four (4) hours following the Trading Intervals for which Meter Data was collected pursuant to Section 4.13.4.5(a).

To provide a maximum adjustment factor of 1.4, the adjusted percentage can have a maximum value of one hundred-forty (140) percent and a minimum value of seventy-one (71) percent.

(d) If the Proxy Demand Resource or Reliability Demand Response Resource elects to provide Meter Data reflecting the total gross Demand at all times, independent of any offsetting Energy, the offsetting Energy must be metered separate from Load to enable the accurate calculation of total gross consumption.

**4.13.4.6 Electric Vehicle Supply Equipment (EVSE)**

Proxy Demand Resources may include or consist entirely of EVSEs. Proxy Demand Resources may elect to use different methodologies to calculate the Customer Load Baselines and Demand Response Energy Measurements of (i) their EVSEs, including electric vehicle charging Load, and (ii) any other Load or behind-the-meter Generation participating as Proxy Demand Resources. Where a Proxy Demand Resource elects to do so, the EVSE Load must be metered separately from any other Load or Generation. Individual EVSEs may be aggregated into Proxy Demand Resources consistent with Section 4.13.2. Where the Load at the EVSE’s Location also participates as a Proxy Demand Resource, the EVSE must participate in the same Proxy Demand Resource, but may elect to have a separately metered Customer Load Baseline and Demand Response Energy Measurement consistent with this Section. To calculate EVSE Customer Load Baselines and Demand Response Energy Measurements under this section, non-residential EVSEs may use the ten-in-ten methodology, and residential EVSEs may use the ten-in-ten methodology and the five-in-ten methodology. Scheduling Coordinators for EVSEs participating under this section will not apply an adjustment factor pursuant to subsection (c) of either methodology. Non-EVSE Load also participating in the EVSE’s Proxy Demand Resource may use any eligible methodology for its Customer Load Baseline and Demand Response Energy Measurement.

**4.13.4.7 Load-Shift Methodology**

Only Proxy Demand Resources using behind-the-meter energy storage may elect to use the load-shift methodology described in this Section. The energy storage must be metered separately from other Load or Generation. Proxy Demand Resources using this methodology will consist of two Resource IDs:

• A consumption Resource ID to account for the energy storage charging alone; and

• A curtailment Resource ID to account for the energy storage discharging to offset onsite Demand and, including if the Demand Response Provider elects, any Demand curtailment by the onsite Load independent of the energy storage.

The CAISO will use reasonable efforts to optimize both Resource IDs to avoid conflicting Schedules. Scheduling Coordinators will be responsible for calculating separate Customer Load and Generator Output Baselines for the curtailment Resource ID and the consumption Resource ID.

 (a) Meter Data will be collected for each Resource ID for the fifteen (15) minute interval as the Trading Interval on calendar days preceding the Trading Day on which the Demand Response Event occurred for which the baselines are calculated. To determine the fifteen (15) minute intervals for which the Meter Data will be collected, the calculation will work sequentially backwards from the Trading Day under examination up to a maximum of forty-five (45) calendar days prior to the Trading Day, including only business days if the Trading Day is a business day, including only non-business days if the Trading Day is a non-business day, and excluding intervals in which the Proxy Demand Resource was subject to an Outage or previously provided Demand Response Services (other than capacity awarded for AS or RUC). The calculation will have complete Meter Data for this purpose if and when it is able to collect Meter Data for its target number of intervals the same as the Trading Interval, which target number is ten (10) intervals if the Trading Day is a business day or four (4) intervals if the Trading Day is a non-business day. If these targets cannot be met, a minimum of five (5) intervals if the Trading Day is a business day or a minimum of four (4) intervals if the Trading Day is a non-business day must be collected. If these targets cannot be met, the baselines will be set at zero.

(b) Meter Data for the consumption Resource ID will include only Meter Data at or below 0 MWh. In intervals where the Meter Data is above 0 MWh, the Scheduling Coordinator will consider the Meter Data at 0 MWh for the consumption Resource ID.

(c) Meter Data for the curtailment Resource ID will include only Meter Data at or above 0 MWh. In intervals where the Meter Data is below 0 MWh, the Scheduling Coordinator will consider the Meter Data at 0 MWh for the curtailment Resource ID. The Scheduling Coordinator will exclude Meter Data for Energy from the curtailment Resource ID that exceeds the onsite Demand.

 (d) The Scheduling Coordinator will be responsible for calculating the simple hourly average of the collected Meter Data to determine the baseline amounts of Energy provided or consumed by each Resource ID.

The Demand Response Provider may elect to include Demand Response Energy Measurements for the onsite Load, which the Scheduling Coordinator will add to the Demand Response Energy Measurement for the curtailment Resource ID pursuant to Section 11.6.7. If the Demand Response Provider elects to do so, the Scheduling Coordinator will calculate a separate Customer Load Baseline for the onsite Load, excluding the Energy or Demand from the energy storage. If the onsite Load is residential, the Scheduling Coordinator may calculate its Customer Load Baseline using the ten-in-ten methodology, five-in-ten methodology, or weather matching methodology performance methodology. If the onsite Load is non-residential, the Scheduling Coordinator may calculate its Customer Load Baseline using the ten-in-ten methodology or weather matching methodology performance methodology.

### 4.13.5 Characteristics of PDRs and RDRRs

**4.13.5.1 Availability to Provide Demand Response Services**

Each Proxy Demand Resource and Reliability Demand Response Resource shall become available to provide Demand Response Services pursuant to the Demand Response Provider Agreement following the date on which the Demand Response Provider Agreement is executed by all parties thereto, as specified by the parties, and shall be available to provide Demand Response Services until the Demand Response Provider Agreement is terminated as set forth in the Demand Response Provider Agreement.

**4.13.5.2 Size Limits for PDRs and RDRRs**

**4.13.5.2.1 PDRs**

The minimum Load curtailment of a Proxy Demand Resource shall be no smaller than 0.1 MW.  Loads may be aggregated together to achieve the 0.1 MW threshold. There is no upper limit on the maximum Load curtailment of a Proxy Demand Resource.

**4.13.5.2.2 RDRRs**

The minimum Load curtailment of a Reliability Demand Response Resource shall be no smaller than 0.5 MW. Loads may be aggregated together to achieve the 0.5 MW threshold. The maximum Load curtailment of a Reliability Demand Response Resource that selects the Discrete Real-Time Dispatch Option shall be no larger than 100 MW. The CAISO will approve uses above 100 MW where:

1. the Demand Response Provider attests that the Reliability Demand Response Resource (1) is located at a single site; (2) cannot safely or operationally be split into multiple loads; and (3) does not have the ability to operate under the Marginal Real-Time Dispatch Option; and
2. the CAISO determines that the Reliability Demand Response Resource’s use of the Discrete Real-Time Dispatch Option does not cause significant reliability issues.

There is no upper limit on the maximum Load curtailment of a Reliability Demand Response Resource that selects the Marginal Real-Time Dispatch Option.

**4.13.5.3 Dispatch Parameters for RDRRs**

Each Reliability Demand Response Resource shall be capable of reaching its maximum Load curtailment within forty (40) minutes after it receives a Dispatch Instruction, and shall be capable of providing Demand Response Services for at least four (4) consecutive hours per Demand Response Event. Each Reliability Demand Response Resource shall have a minimum run time of no more than one (1) hour.

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## 4.17 Distributed Energy Resource Aggregations

### 4.17.1 CAISO Relationship with Distributed Energy Resource Providers

The CAISO will accept Bids from Distributed Energy Resource Aggregations only if such Distributed Energy Resource Aggregations are represented by a Distributed Energy Resource Provider that has entered into a Distributed Energy Resource Provider Agreement with the CAISO to comply with all applicable provisions of the CAISO Tariff as they may be amended from time to time. The CAISO will not accept Bids from a Distributed Energy Resource Aggregation other than through a Scheduling Coordinator. The Scheduling Coordinator may be the Distributed Energy Resource Provider itself or another entity.

### 4.17.2 Responsibilities of Distributed Energy Resource Providers

The following general responsibilities apply to Distributed Energy Resource Providers:

(a) Each Distributed Energy Resource Provider will operate and maintain its Distributed Energy Resource Aggregations consistent with applicable provisions of the CAISO Tariff.

(b) Each Distributed Energy Resource Provider will comply with applicable Utility Distribution Company or Metered Subsystem tariffs and operating procedures incorporated therein as well as applicable requirements of the Local Regulatory Authority, if any. Each Distributed Energy Resource Provider will ensure that Distributed Energy Resources that comprise a Distributed Energy Resource Aggregation under its control comply with applicable Utility Distribution Company or Metered Subsystem tariffs and operating procedures incorporated therein as well as applicable requirements of the Local Regulatory Authority, if any.

(c) Each Distributed Energy Resource Provider will comply with Applicable Reliability Criteria to the extent they apply.

(d) Each Distributed Energy Resource Provider will operate and maintain its Distributed Energy Resource Aggregation(s) consistent with applicable Operating Procedures and Business Practice Manuals established by the CAISO.

(e) Each Distributed Energy Resource Provider will operate its Distributed Energy Resource Aggregation(s) in a manner consistent with limitations established by or operating orders of the Utility Distribution Company or Metered Subsystem.

(f) The CAISO will coordinate with the applicable Utility Distribution Company or Metered subsystem to avoid conflicting operational directives, which may include but is not limited to sharing Dispatch Instructions.

### 4.17.3 Requirements for Distributed Energy Resource Aggregations

The following requirements apply to Distributed Energy Resource Aggregations:

(a) A Distributed Energy Resource Aggregation will consist of one (1) or more Distributed Energy Resources.

(b) A Distributed Energy Resource may not participate in more than one Distributed Energy Resource Aggregation.

(c) A Distributed Energy Resource participating in a Distributed Energy Resource Aggregation may not participate as a resource in the CAISO Market separate from the Distributed Energy Resource Aggregation.

(d) A Distributed Energy Resource participating in a Distributed Energy Resource Aggregation may not also participate in a retail net energy metering program that does not expressly permit wholesale market participation.

(e) Each Distributed Energy Resource Aggregation must be located in a single Sub-LAP.

(f) A Distributed Energy Resource Aggregation must provide a net response at its PNode(s) within its sub-LAP that is consistent with CAISO Dispatch Instructions and applicable Generation Distribution Factors submitted through the Distributed Energy Resource Aggregation’s Bid or as registered in the Master File.

(g) Distributed Energy Resource Aggregations are Scheduling Coordinator Metered Entities. Scheduling Coordinators for a Distributed Energy Resource Aggregation must have entered into a Scheduling Coordinator Metering Agreement with the CAISO. A Distributed Energy Resource participating in a Distributed Energy Resource Aggregation may not also participate in the CAISO Markets as a CAISO Metered Entity.

(h) A Distributed Energy Resource Aggregation may not receive compensation from retail programs for capacity, Energy, or other services it provides the CAISO Markets.

(i) Distributed Curtailment Resources may participate in heterogeneous Distributed Energy Resource Aggregations pursuant to these rules and Section 4.17.8. Aggregations of only Distributed Curtailment Resources without other Distributed Energy Resources that inject Energy must participate as Proxy Demand Resources or Reliability Demand Response Resources.

### 4.17.4 Identification of Distributed Energy Resources

Each Distributed Energy Resource Provider will provide information, as described in the Business Practice Manual, identifying each of its Distributed Energy Resource Aggregations and such information regarding the location, capacity, operating characteristics and applicable Generation Distribution Factors of its Distributed Energy Resource Aggregation(s) as may be reasonably requested from time to time by the CAISO, and when the information changes due to the removal, addition, or modification of a Distributed Energy Resource or Distributed Curtailment Resource within the Distributed Energy Resource Aggregation. All information provided to the CAISO by a Distributed Energy Resource Provider regarding the operational and technical characteristics of its Distributed Energy Resource Aggregation(s) must be an accurate reflection of the design capabilities of the resources and its constituent equipment when operating at maximum sustainable performance over Minimum Run Time, recognizing that resource performance may degrade over time. Information registered in the Master File by a Scheduling Coordinator must also conform to any additional definitional requirements in Appendix A as may exist as to that information..

As further described in the Business Practice Manual, the CAISO will confer with the applicable Utility Distribution Company or Metered Subsystem regarding information provided about Distributed Energy Resources comprising a Distributed Energy Resource Aggregation(s).  The Utility Distribution Company or Metered Subsystem will have an opportunity to provide written comments within thirty (30) days regarding the accuracy of the information about Distributed Energy Resources comprising a Distributed Energy Resource Aggregation(s) or raise concerns with respect to whether the Distributed Energy Resources (1) are participating in another Distributed Energy Resource Aggregation; (2) are participating as a Proxy Demand Response resource or a Reliability Demand Response Resource; (3) are participating in a retail net energy metering program that does not expressly permit wholesale market participation; (4) do not comply with applicable Utility Distribution Company tariffs or requirements of the relevant Local Regulatory Authority; (5) receive compensation from retail programs for capacity, Energy, or other services that would be offered to the CAISO Markets; or (6) may pose a significant threat to the safe and reliable operation of the Distribution System, if operated as part of a Distributed Energy Resource Aggregation. If the Utility Distribution Company or Metered Subsystem raises concerns based on these factors, the CAISO will provide the Distributed Energy Resource Provider with the Utility Distribution Company or Metered Subsystem’s written comments, and the Distributed Energy Resource Provider will resolve those concerns with the Utility Distribution Company or Metered Subsystem prior to the CAISO allowing the individual Distributed Energy Resource to participate in a Distributed Energy Resource Aggregation. Any disputes regarding these concerns shall be undertaken with the applicable Governmental Authority for the Utility Distribution Company or Metered Subsystem and shall not be arbitrated or in any way resolved through a CAISO dispute resolution mechanism.

**4.17.4.1 Modifications to Distributed Energy Resource Aggregations**

The Distributed Energy Resource Provider will notify the CAISO of any changes to the information it provided during the registration process due to the removal, addition, or modification of a Distributed Energy Resource or Distributed Curtailment Resource within the Distributed Energy Resource Aggregation. The Distributed Energy Resource Provider also will notify the CAISO of any changes to its Distributed Energy Resource Aggregation’s physical or operational characteristics. The CAISO will notify the applicable Utility Distribution Company or Metered Subsystem of any changes, and the Utility Distribution Company or Metered Subsystem will have fourteen (14) days to provide the CAISO any written comments raising concerns under Section 4.17.4.

### 4.17.5 Characteristics of Distributed Energy Resource Aggregations

**4.17.5.1 Size Limits**

A Distributed Energy Resource Aggregation will be no smaller than 100kW. A Distributed Energy Resource Aggregation that includes Distributed Energy Resources located at different PNodes will be no larger than 20 MW.

**4.17.5.2 Metering and Telemetry**

Scheduling Coordinators shall submit to the CAISO Actual Settlement Quality Meter Data or Estimated Settlement Quality Meter Data for Distributed Energy Resource Aggregations they represent for each Settlement Period in an Operating Day. Distributed Energy Resources and Distributed Curtailment Resources participating in a Distributed Energy Resource Aggregation will be directly metered pursuant to a meter that complies with any applicable Utility Distribution Company tariff and any standards of the relevant Local Regulatory Authority or, if no such tariff exists or no standards have been set by that Local Regulatory Authority, the metering standards as further detailed in the CAISO’s Business Practice Manual. Distributed Energy Resource Providers must make Settlement Quality Meter Data from individual Distributed Energy Resources and Distributed Curtailment Resources comprising a Distributed Energy Resource Aggregation available to the CAISO upon request.

Distributed Energy Resource Providers shall provide information regarding Distributed Energy Resource Aggregation(s) with a rated capacity of 10 MW or greater or, if the Distributed Energy Resource Aggregation(s) provides Ancillary Services, through telemetry to the CAISO’s EMS in accordance with the CAISO’s standards for direct telemetry and consistent with the requirement for telemetry set forth in Section 7.6.1.

### 4.17.6 Operating Requirements

Distributed Energy Resource Aggregations will respond to CAISO Dispatch Instructions. The CAISO may dispatch a Distributed Energy Resource Aggregation to the extent the Distributed Energy Resource Aggregation bids or schedules into the CAISO Markets and receives an award. The CAISO may also issue an Exceptional Dispatch Instruction for the Distributed Energy Resource Aggregation for reliability pursuant to Section 34.10. Distributed Energy Resource Aggregations shall respond to Dispatch Instructions consistent with Generation Distribution Factors for the Distributed Energy Resource Aggregation.

Each Distributed Energy Resource Provider will operate its Distributed Energy Resource Aggregation(s) in a manner consistent with limitations or operating orders established by the Utility Distribution Company or Metered Subsystem. Scheduling Coordinators for Distributed Energy Resources Providers shall submit Outages to the CAISO as necessary to reflect any distribution constraints impacting Distributed Energy Resources that comprise a Distributed Energy Resource Aggregation under its control. The CAISO shall have the authority to coordinate and approve Outage schedules for the Distributed Energy Resource Aggregation(s) listed in a Distributed Energy Resource Provider Agreement, in accordance with the provisions of Section 9.

\* \* \*

# 6. Communications

## 6.1 Methods of Communication

### 6.1.1 Full-Time Communications Facility Requirements

Each Scheduling Coordinator, Utility Distribution Company, Participating TO, Participating Generator, Balancing Authority (to the extent the agreement between the Balancing Authority and the CAISO so provides), and MSS Operator must provide a communications facility manned twenty-four (24) hours a day, seven (7) days a week capable of receiving Dispatch Instructions issued by the CAISO.

### 6.1.2 Information Transfer from Scheduling Coordinator to CAISO

Unless otherwise agreed by the CAISO, Scheduling Coordinators who wish to submit Bids into CAISO Markets must submit the information to the CAISO’s secure communication system. Scheduling Coordinators that wish to submit Dynamic Schedules or Bids for Ancillary Services to the CAISO must also comply with the applicable requirements of Sections 4.5.4.3, 8.3.7, and 8.4.5.

### 6.1.3 Submitting Information to the Secure Communication System

For Scheduling Coordinators submitting information to the CAISO’s secure communication system, each such Scheduling Coordinator shall establish a network connection with the CAISO’s secure communication system. Link initialization procedures shall be necessary to establish a connection to the CAISO’s secure communication system. In order to log in, each Scheduling Coordinator will be furnished a digital certificate by the CAISO.

**6.1.3.1** The CAISO will make available data templates and validation rules information that provides a description of the templates which will be utilized to enter data into the CAISO's secure communication system.

### 6.1.4 Information Transfer from CAISO to Scheduling Coordinator

Unless otherwise agreed between a Scheduling Coordinator and the CAISO, the CAISO shall furnish scheduling information to Scheduling Coordinators by electronic transfer as described in Section 6.  If electronic data transfer is not available, the information may be furnished by facsimile.  If it is not possible to communicate with the Scheduling Coordinator using the primary means of communication, an alternate means of communication shall be selected by the CAISO.

### 6.1.5 Information to be Provided by Connected Entities to CAISO

Each Connected Entity shall provide the CAISO:

(a) A single and alternative telephone number and a single and alternative facsimile number by which the CAISO may contact twenty-four (24) hours a day a representative of the Connected Entity in, or in relation to, a System Emergency; and

(b) The names or titles of the Connected Entity’s representatives who may be contacted at such telephone and facsimile numbers.

**6.1.5.1** Each representative specified pursuant to this Section 6.1.5 shall be a person having appropriate experience, qualification, authority, responsibility and accountability within the Connected Entity to act as the primary contact for the CAISO in the event of a System Emergency.

**6.1.5.2** The details required under this Section 6.1.5 shall at all times be maintained up to date and the Connected Entity shall notify the CAISO of any changes promptly and as far in advance as possible.

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# 7. System Operations Under Normal and Emergency Conditions

\* \* \*

## 7.6 Normal System Operations

### 7.6.1 Actions for Maintaining Reliability of CAISO Controlled Grid

The CAISO shall obtain the control over Generating Units that it needs to control the CAISO Controlled Grid and maintain reliability by ensuring that sufficient Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services are procured through the CAISO Markets. When the CAISO responds to events or circumstances, it shall first use the generation control it is able to obtain from Bids it has received to respond to the operating event and maintain reliability. Only when the CAISO has used the Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services that are available to it and that are effective in responding to the problem and the CAISO is still in need of additional control over Generating Units, shall the CAISO assume supervisory control over other Generating Units. It is expected that at this point, the operational circumstances will be so severe that a Real-Time system problem or emergency condition could be in existence or imminent.

Each Participating Generator shall take, at the direction of the CAISO, such actions affecting such Generator as the CAISO determines to be necessary to maintain the reliability of the CAISO Controlled Grid. Such actions shall include (but are not limited to):

(a) compliance with Dispatch Instructions including instructions to deliver Energy and Ancillary Services in Real-Time pursuant to the AS Awards, Day-Ahead Schedules and FMM Schedules, and FMM AS Awards;

(b) compliance with the system operation requirements set out in this Section 7;

(c) notification to the CAISO of the persons to whom an instruction of the CAISO should be directed on a 24-hour basis, including their telephone and facsimile numbers; and

(d) the provision of communications, telemetry and direct control requirements, including the establishment of a direct communication link from the control room of the Generator to the CAISO in a manner that ensures that the CAISO will have the ability, consistent with this CAISO Tariff, to direct the operations of the Generator as necessary to maintain the reliability of the CAISO Controlled Grid, except that a Participating Generator will be exempt from CAISO requirements imposed in accordance with this subsection (d) with regard to any Generating Unit with a rated capacity of less than ten (10) MW, unless that Generating Unit is certified by the CAISO to provide Ancillary Services.

## 7.7 Management of Abnormal System Conditions

### 7.7.1 CAISO Actions in Imminent or Actual System Emergency

**(a)** **Declaration of System Emergency.** When, in the judgment of the CAISO, a System Emergency has occurred or is imminent, the CAISO will declare a System Emergency and issue an Emergency Notice to that effect, setting forth the actions that the CAISO is taking to address the System Emergency.

**(b)** **Subsequent Notices Regarding System Emergency.** Each time that the CAISO initiates any of the actions in Section 7.7.1(c) in response to a System Emergency, and at such time that the CAISO terminates any such action or resolves the System Emergency, the CAISO will issue a subsequent Emergency Notice setting forth the action or determination.

**(c)** **Actions in Response to System Emergency.** In response to a System Emergency, the CAISO may take any or all of the following actions as necessary to preserve or restore reliable, safe, and efficient service as quickly as reasonably practicable:

(1) suspend the CAISO Markets and apply an Administrative Price in accordance with Section 7.7.3;

(2) authorize full use of Black Start Generating Units;

(3) initiate full control of manual Load Shedding, in accordance with Section 7.7.3(c);

(4) authorize the curtailment of Curtailable Demand (even though not scheduled as an Ancillary Service) in accordance with Section 7.7.3(c); and

(5) take such other action that it considers necessary to preserve or restore stable operation of the CAISO Controlled Grid, to the extent such actions are consistent with Good Utility Practice and Applicable Reliability Criteria and not inconsistent with the CAISO Tariff.

**(d) Termination of System Emergency.** The CAISO will terminate the System Emergency and suspend the actions taken in response to the System Emergency when it determines, after conferring, as necessary, with Reliability Coordinators within the WECC, that the major factors contributing to the System Emergency have been corrected, and all involuntarily interrupted Demand is back in service (except interrupted Curtailable Demand selected as an Ancillary Service).

**(e)** **Coordination with Neighboring Balancing Authority Areas.** The CAISO shall keep system operators in adjacent Balancing Authority Areas informed, as necessary, as to the nature and extent of the System Emergency in accordance with WECC procedures.

**(f) Emergency Guidelines.** The CAISO shall issue guidelines for all Market Participants to follow during a System Emergency consistent with the responsibilities set forth in Section 7.7.2 and in applicable Operating Procedures.

### 7.7.2 Market Participant Responsibilities in System Emergencies.

**(a)** **Response to CAISO Dispatch Instructions.** All Market Participants shall respond immediately to CAISO Dispatch Instructions during System Emergencies.

**(b) Responsibilities of UDCs and MSS Operators During a System Emergency**

**(1) Compliance with Directions and Procedures.**  In the event of a System Emergency, UDCs and MSS Operators shall comply with all directions from the CAISO concerning the avoidance, management, and alleviation of the System Emergency and shall comply with all procedures concerning System Emergencies set forth in this CAISO Tariff, the Business Practice Manuals, and the Operating Procedures. and shall comply with all procedures concerning System Emergencies set forth in the CAISO Tariff, Business Practice Manuals and Operating Procedures.

**(2) Communications.** During a System Emergency, the CAISO shall communicate with the UDCs and MSS Operators through their respective control centers and in accordance with procedures established in individual UDC and MSS Operating Agreements.

**(3) Notifications of End-Use Customers.** Each UDC and MSS Operator will notify its End-Use Customers connected to the UDC’s or the MSS’s Distribution System of any voluntary curtailments notified to the UDC or to the MSS Operator by the CAISO pursuant to the provisions of the Electrical Emergency Plan.

**(c) Responsibilities of Generating Units, System Units and System Resources During System Emergencies**

**(1) In General.** All Generating Units and System Units that are owned or controlled by a Participating Generator are (without limitation to the CAISO’s other rights under this CAISO Tariff) subject to control by the CAISO during a System Emergency and the CAISO shall have the authority to instruct a Participating Generator to bring its Generating Unit on-line or off-line or to increase or curtail the output of the Generating Unit and to alter scheduled deliveries of Energy and Ancillary Services into or out of the CAISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency or to retain Operational Control over the CAISO Controlled Grid during an actual System Emergency.

**(2) Prerequisite for Dispatch Instructions.** The CAISO shall, where reasonably practicable, use Ancillary Services which it has the contractual right to instruct and which are capable of contributing to containing or correcting the actual, imminent, or threatened System Emergency prior to issuing instructions to a Participating Generator under this subsection, except that the CAISO need not take such action if it determines such action is unlikely to be effective.

**(3)** **Legacy** **RMR Condition 2 Units.**

**(A) Prerequisite for Dispatch Instructions.** The CAISO shall only instruct a Legacy RMR Unit whose owner has selected Condition 2 of its Legacy RMR Contract to start-up and change its output if the CAISO has reasonably used all other available and effective resources to prevent a threatened System Emergency without declaring that a System Emergency exists.

**(B) Compensation.** If the CAISO dispatches a Condition 2 RMR Unit pursuant to subparagraph (A), it shall compensate that unit in accordance with Section 11.5.6.3 and allocate the costs in accordance with Section 11.5.6.3.2.

**(4)** **Qualifying Facilities.** A Scheduling Coordinator that represents a QF subject to an Existing QF Contract that is not subject to a PGA or Net Scheduled PGA will make reasonable efforts to require such QFs to comply with the CAISO’s instructions during a System Emergency without penalty for failure to do so.

### 7.7.3 Suspension of CAISO Markets and Application of Administrative Price.

**(a) In General.**  In the absence of a Market Disruption, the CAISO may suspend the CAISO Markets and apply Administrative Prices as provided in Section 7.7.9, if the CAISO determines that such suspension is necessary in order to prevent, contain, or correct a System Emergency in accordance with this Section 7.7.3.

**(b) Suspension of DAM.**

**(1) Condition for Suspension.** The CAISO will not suspend the operation of the Day-Ahead Market to manage a System Emergency unless there has been a total or major collapse of all or part of the CAISO Controlled Grid and the CAISO is in the process of restoring it or if the CAISO anticipates that it will not publish DAM results for any reason.

**(2) Notification.** In the event the CAISO determines it may suspend the DAM, it will notify Market Participants as set forth in Section 7.7.9(b)(2).

**(c) Suspension of RTM.** Before suspending the RTM to prevent or manage a System Emergency, the CAISO may take any or all of the following actions that it deems effective to mitigate the System Emergency –

(1) dispatch all reasonably effective Supply Bids offered or available to it regardless of price (including all Energy Bids and Ancillary Services Bids);

(2) subject to Section 3, notify the UDCs when the conditions to implement their existing Load curtailment programs have been met in accordance with their terms;

(3) dispatch or curtail all price-responsive Demand that has been bid into the Day-Ahead Market and exercise its rights under all Load curtailment contracts available to it;

(4) at its discretion, require direct control over Curtailable Demand;

(5) dispatch all interruptible Loads made available by UDCs to the CAISO in accordance with the relevant agreements with UDCs; or

(6) direct a UDC or an MSS Operator to disconnect load from the CAISO Controlled Grid in accordance with the prioritization schedule developed pursuant to Section 7.7.4(b), and exercise Load Shedding to curtail Demand on an involuntary basis, to the extent that the CAISO considers necessary or as instructed by the Reliability Coordinator.

**(d)** If a Load curtailment is required to manage System Emergencies, the CAISO will determine the amount and location of Load to be reduced. In those instances when the CAISO requires load-shedding assistance from the entire CAISO Balancing Authority Area to preserve or restore stable operation of the CAISO Controlled Grid and to the extent practicable, the CAISO will allocate a portion to each UDC or MSS Operator based on the ratio of its Demand (at the time of the Balancing Authority Area annual peak for the previous year) to total Balancing Authority Area annual peak Demand for the previous year taking into account system considerations and the UDC’s or MSS Operator’s curtailment rights under their tariffs. Each UDC or MSS Operator shall be responsible for notifying its customers and Generators connected to its system of curtailments and service interruption.

**(e) Termination of Market Suspension.** The suspension will cease as soon as conditions allow.

### 7.7.4 Preparatory Actions for a System Emergency

**(a) Periodic Tests of Emergency Procedures.** The CAISO shall develop and administer periodic tests of System Emergency procedures designed to ensure that Participating Transmission Owners and Scheduling Coordinators received the information required to respond to operating conditions, including System Emergencies.

**(b) Prioritization Schedule for Shedding And Restoring Load.** On an annual basis, the CAISO will, in collaboration with UDCs and MSSs and subject to the provisions of Section 3, develop a prioritization schedule for Load Shedding should a System Emergency require such action, which shall also establish a sequence for the restoration of Load in the event that multiple UDCs or MSSs are affected by service interruptions and Load must be restored in blocks.

### 7.7.5 Actions Subsequent to a System Emergency

(a) **Review of Major Outages.** The CAISO, with the cooperation of any affected UDC, shall jointly perform a review following a major Outage that affects at least ten (10) percent of the Load served by the Distribution System of a UDC or any Outage that results in major damage to the CAISO Controlled Grid or to the health and safety of personnel, which shall address the cause of the Outage, the response time and effectiveness of emergency management efforts, and whether the operation, maintenance, or scheduling practices of the CAISO, any Participating TOs, Participating Generators, Eligible Customers, or UDCs enhanced or undermined the ability of the CAISO to maintain or restore service efficiently and in a timely manner.

**(b) Report.**  The CAISO shall prepare a report on all major outages described in subsection (a) and shall share the report with Participating TOs, Participating Generators, Eligible Customers, and UDCs.

**(c) Provision of Information and Opportunity to Comment.** The CAISO shall seek the views of any Participating TOs, Participating Generators, Eligible Customers, UDCs, and Scheduling Coordinators affected by a System Emergency in the preparation of a report under subsection (b), and such affected entities shall promptly provide information requested by the CAISO. The CAISO shall give such affected entities an opportunity to comment on any issues arising during the preparation of the report.

### 7.7.6 System Operations in the Event of a Market Disruption

**(a) Actions in the Event of a Market Disruption, to Prevent a Market Disruption, or to Minimize the Extent of a Market Disruption.**  The CAISO may take one or more of the following actions in the event of a Market Disruption, to prevent a Market Disruption, or to minimize the extent of a Market Disruption:

 (1) postpone the closure of the applicable CAISO Market;

(2) remove Bids, including Self-Schedules, that have resulted in a Market Disruption previously, pursuant to Section 7.7.7;

(3) suspend the applicable CAISO Market and manually copy Bids, including Self-Schedules, from the previous day or other applicable market period;

(4) suspend the applicable CAISO Market and use submitted Bids, including Self-Schedules, to the extent possible;

(5) suspend the applicable CAISO Market, in which case import/export schedules shall be determined by submittal of E-Tags;

(6) suspend the applicable CAISO Market and apply Administrative Prices established pursuant to Section 7.7.9;

(7) utilize Exceptional Dispatch and issue Operating Instructions for resources to be committed and dispatched to meet Demand;

(8) suspend or limit the ability of all Scheduling Coordinators to submit Virtual Bids on behalf of Convergence Bidding Entities at specific Eligible PNodes or Eligible Aggregated PNodes, or at all Eligible PNodes or Eligible Aggregated PNodes; or

(9) postpone the publication of DAM market results.

**(b)** **Choices of Action to Prevent a Market Disruption, in the Event of a Market Disruption, or to Minimize the Extent of a Market Disruption.**  The CAISO’s choice of action in the event of a Market Disruption shall depend on the CAISO Market that is disrupted, the cause of the Market Disruption, the expected time to resolve the Market Disruption, and the status of submitted Bids and Self-Schedules at the time the Market Disruption occurs.

**(c) Notification.** In the event the CAISO may not publish DAM results, it will notify Market Participants as set forth in Section 7.7.9(b)(2).

**(d)** **Reports.**  The CAISO shall include reports on actions taken pursuant to this Section 7.7.6 in the Exceptional Dispatch report provided in Section 34.11.4 of the CAISO Tariff and shall include –

(1) the frequency and types of actions taken by the CAISO pursuant to this Section 7.7.6;

(2) the nature of the specific Market Disruptions that caused the CAISO to take action and the CAISO rationale for taking such actions, or the Market Disruption that was successfully prevented or minimized by the CAISO as a result of taking action pursuant to its authority under this Section 7.7.6; and

(3) general information on the Bids removed pursuant to Section 7.7.7, which may include the megawatt quantity, point of interconnection, specification of the Day-Ahead versus Real-Time Bid, and Energy or Ancillary Services Bid, and the CAISO’s rationale for removal; except that any Scheduling Coordinator-specific individual Bid information will be submitted on a confidential basis consistent with FERC’s rules and regulations governing requests for confidential treatment of commercially sensitive information.

### 7.7.7 Removal of Bids in the Event of a Market Disruption, to Prevent a Market Disruption, or to Minimize the Extent of a Market Disruption

**(a) Types of Bids.**  The types of Bids that the CAISO may remove are Bids that are not feasible based on the misalignment of resource-specific conditions and physical constraints represented in the Master File, current outage information, and the Bid itself.

**(b)** **Removal of a Portion of a Bid.** The CAISO may remove part of a Bid, but retain other parts of the Bid for the applicable CAISO Market run and interval for the same or a different product, and may retain parts of the Bid for subsequent CAISO Market runs or intervals.

**(c) Removal of a Bid Pursuant to Section 7.7.6(a)(2).**  If a Bid must be removed pursuant to Section 7.7.6(a)(2), the CAISO will remove the entire Bid for that particular service and market.

**(d) Resubmittal of Bids.** The Scheduling Coordinator may resubmit removed Bids in subsequent CAISO Markets, provided the Scheduling Coordinator complies with any operator instructions regarding the subject Bids.

**(e)** **RUC Bids.** In the event the CAISO removes a Bid from an IFM run, the RUC Availability Bid associated with the removed IFM Bid may still be accepted for the corresponding RUC run, unless the CAISO determines that the RUC Availability Bid is the cause of the disruption.

**(f)** **RTM Bids.**  If the CAISO removes a Bid in the advisory RTUC or RTD runs during the Real-Time Market, the CAISO may still use the removed Bid in the binding runs of the Real-Time Market for the same interval if the problems previously experienced with the Bid do not arise.

**(g) Energy Component of Ancillary Services Bids.**  If the CAISO removes an Ancillary Services Bid submitted to the Real-Time Market, the CAISO may retain the associated Energy Bid for that CAISO Market run.

**(h)** **Settlement Consequences of Removal of Bids**

**(1) Day-Ahead Market.**  In the event that a Bid is removed from the Day-Ahead Market, the Scheduling Coordinator whose Bid is removed will not be subject to Settlement for the Day-Ahead Market for the affected service.

**(2) Ancillary Services.**  In the case of Ancillary Services Bids, including Submissions to Self-Provide an Ancillary Service, that are removed from the Day-Ahead Market, the Scheduling Coordinator will not receive Settlement for the Ancillary Services in the Day-Ahead Market and will not receive an opportunity cost payment in the Day-Ahead Market for the offered service.

**(3)** **Exceptional Dispatch.**  In the event that a Bid is removed from a CAISO Market run or interval, the CAISO may subsequently be required to issue an Exceptional Dispatch for the resource, in which case the Scheduling Coordinator will receive Exceptional Dispatch Settlement as provided in Section 11.5.6.

**(4) Demand Bids.** In the event that a Demand Bid is removed from the Day-Ahead Market, because no Demand Bids for load can be submitted in the Real-Time Market, Scheduling Coordinators for the load not cleared in the Day-Ahead Market will be settled as Uninstructed Imbalance Energy as provided in Section 11.5.2.

**(i) Reporting to Affected Scheduling Coordinators.**  To the extent practicable, the CAISO will contact a Scheduling Coordinator’s representative before removing a Bid and advise the representative of the issues encountered with the Bid as soon as practicable, but no later than three (3) Business Days, after the applicable Bid was removed and will provide information specifying when its Bid was removed and the nature of the disruption.

### 7.7.8 Under Frequency Load Shedding (UFLS).

Each UDC’s UDCOA with the CAISO and each MSS Agreement through which the MSS Operator agrees to comply with the provisions of the CAISO Tariff shall describe the UFLS program for that UDC or for that MSS.

### 7.7.9 Application of Administration Prices and Use of Prior Market Results

**(a)** **In General.** To manage an imminent or actual System Emergency or to prevent, manage, or minimize the extent of a Market Disruption, the CAISO will apply prior market results in accordance with this Section 7.7.9.

**(b)** **Day-Ahead Market.**

**(1) Market Results.** In the case of a suspension of the Day-Ahead Market –

(A) the CAISO shall use the Day-Ahead Market market results (except for Virtual Awards), as applicable, from the previous day for the Day-Ahead Market if the CAISO determines, based on expected system conditions, that using such market results will provide a reasonable profile of Schedules to meet the needs of the Real-Time;

(B) if the CAISO determines, based on expected system conditions, that using the Day-Ahead Market market results described in Section 7.7.9(b)(1)(A) will not reasonably meet the needs of the Real-Time, the CAISO may rely solely on the use of Exceptional Dispatch and other manual instructions and on the Real-Time Market market results, as applicable for pricing and Settlement purposes, except that notwithstanding Section 11.2., Congestion Revenue Rights will be settled using the hourly average of the 15-minute FMM prices for each hour of the Real-Time Market.

**(2)** **Notification.** In the event the CAISO has not published the Day-Ahead Market market results or determines it may suspend the Day-Ahead Market, it will notify Market Participants by 6:00 p.m., indicating whether the CAISO anticipates it will –

(i) publish the Day-Ahead Market market results, and if so, when;

(ii) use the previous day’s Day-Ahead Market market results pursuant to Section 7.7.9(b)(1)(A); or

(iii) rely on the use of Exceptional Dispatch and other manual instructions and on the Real-Time Market market results pursuant to Section 7.7.9(b)(1)(B).

**(c) Real-Time Market Not Suspended.** In the case of a Market Disruption of the Real-Time Market when the Real-Time Market has not been suspended –

(1) if market results are unavailable for fewer than four (4) consecutive 15-minute FMM intervals, the CAISO shall use the FMM market results, as applicable, for the FMM interval immediately preceding the FMM interval(s) for which FMM market results are unavailable;

(2) if market results are unavailable for fewer than twelve (12) consecutive 5-minute Dispatch Intervals, the CAISO shall use the RTD market results, as applicable, for the Dispatch Interval immediately preceding the Dispatch Interval(s) for which market results are unavailable;

(3) if market results are unavailable for at least four (4) consecutive 15-minute FMM intervals and market results are available for the RTD during those FMM intervals, the CAISO shall use the average of RTD market results, as applicable, during each such FMM interval and use the market results as applicable from the prior intervals for which market results are unavailable as needed;

(4) if market results are unavailable for at least twelve (12) consecutive 5-minute Dispatch Intervals and market results are available for the FMM during those Dispatch Intervals, the CAISO shall use the FMM market results, as applicable, from the applicable FMM during the Dispatch Intervals;

(5) if market results are unavailable for at least four (4) consecutive 15-minute FMM intervals and market results are unavailable for the RTD during those FMM intervals, the CAISO shall use the Day-Ahead Market market results, as applicable, for the corresponding Trading Hour for which market results are unavailable; and(6) if market results are unavailable for at least twelve (12) consecutive 5-minute Dispatch Intervals and market results are unavailable for the FMM during those Dispatch Intervals, the CAISO shall use the previous day’s Day-Ahead Market market results, as applicable, for the corresponding Trading Hour for which market results are unavailable.

**(d) Real-Time Market Suspended.** In circumstances where the Real-Time Market has been suspended, the CAISO shall use the previous day’s Day-Ahead Market market results, as applicable, for the Trading Hour corresponding to the Trading Hour during which the Real-Time Market has been suspended.

**(e)** **Default Provision.** In circumstances that are not described in subsections (a) through (d) of this section or if the market results are for any reason unavailable, the CAISO shall use market results, as applicable, from the most recent preceding applicable interval that produced acceptable market results.

### 7.7.10 CAISO Facility and Equipment Outage

**(a) CAISO’s Secure Communication System Unavailable**

**(1)** **Unavailable Critical Functions.** During a total disruption of the CAISO’s secure communication system –

(A) the CAISO’s scheduling infrastructure computer systems will not be able to communicate with Scheduling Coordinators to receive any type of updated Bid or Schedule information;

(B) the CAISO's scheduling infrastructure computer systems will not be able to communicate Congestion Management information and Schedule changes to the Scheduling Coordinators; and

(C) the CAISO will not be able to communicate general information, including emergency information, to any Market Participants.

**(2) Communications.** During any period that the CAISO’s secure communication system is unavailable, the CAISO shall –

(A) make all reasonable efforts to keep Market Participants aware of current CAISO Controlled Grid status using voice communications;

(B) use the most recent set of Day-Ahead Schedules, RUC Schedules, AS Awards, FMM Schedules, and Dispatch Instructions for each Scheduling Coordinator for the current and all future Settlement Periods and/or Trading Days until the CAISO’s secure communication system is restored; and

(C) attempt to take critical Bids, including ETC and TOR Self-Schedules changes, from Scheduling Coordinators via voice communications as time and personnel availability allow.

**(b)** **Primary CAISO Control Center Unavailability.**

**(1) Loss of all Voice Communications.** In the event of loss of all voice communication at the Primary CAISO Control Center –

(A) the Primary CAISO Control Center will use alternate communications to notify the Backup CAISO Control Center of the loss of voice communications;

(B) the Backup CAISO Control Center will post information on the situation on the CAISO’s secure communication system;

(C) additional voice notifications will be made as time permits; and

(D) once voice communications have been restored to the Primary CAISO Control Center, the CAISO will post this information on the CAISO’s secure communication system.

**(2)** **Complete Unavailability.** In the event that the Primary CAISO Control Center becomes completely unavailable –

(A) the Primary CAISO Control Center will use alternate communications to notify the Backup CAISO Control Center that the Primary CAISO Control Center is unavailable;

(B) the Backup CAISO Control Center will post information on the situation on the CAISO’s secure communication system;

(C) additional voice notifications will be made as time permits;

(D) the Backup CAISO Control Center will post confirmation on the CAISO’s secure communication system that all computer systems are functioning normally (if such is the case) and take complete control of the CAISO Controlled Grid.

(E) the Backup CAISO Control Center will notify the Participating Transmission Owners by direct voice communication of the situation; and.

(F) once the Primary CAISO Control Center is again available, all functions will be transferred back, and the Primary CAISO Control Center will notify all Market Participants via the CAISO’s secure communication system.

**(3) CAISO Energy Management System (EMS) Unavailable.** Should an outage occur to the redundant EMS computer systems in the Primary CAISO Control Center –

(A) EMS operation will transfer to the redundant EMS back up computers at the Backup CAISO Control Center;

(B) the Primary CAISO Control Center will post information on the CAISO’s secure communication system that the Primary CAISO Control Center EMS computer is unavailable and that EMS control has been transferred to the Backup CAISO Control Center; and

(C) when the Primary CAISO Control Center EMS computer is restored, the Backup CAISO Control Center will initiate a transfer of the EMS system back to the Primary CAISO Control Center and the Primary CAISO Control Center will post information on the status of the restored EMS computer system on the CAISO’s secure communication system.

**(c) Backup CAISO Control Center.**

**(1) Loss of all Voice Communications.** In the event of a loss of all voice communications at the Backup CAISO Control Center –

(A) the Backup CAISO Control Center will use alternate communications to notify the Primary CAISO Control Center of the loss of voice communications;

(B) the Primary CAISO Control Center will post information on the situation via the CAISO’s secure communication system;

(C) additional voice notifications will be made as time permits; and

(D) once voice communications have been restored to the Backup CAISO Control Center, the Primary CAISO Control Center will post this information on the CAISO’s secure communication system.

**(2)** **Control Center Completely Unavailable.** In the event that the Backup CAISO Control Center becomes completely unavailable –

(A) the Backup CAISO Control Center will use alternate communications to notify the Primary CAISO Control Center that the Backup CAISO Control Center is unavailable;

(B) the Primary CAISO Control Center will post information on the situation on the CAISO’s secure communication system;

(C) additional voice notifications will be made as time permits;

(D) the Primary CAISO Control Center will post confirmation on the CAISO’s secure communication system that all computer systems are functioning normally (if such is the case) and take complete control of the CAISO Controlled Grid;

(E) the Primary CAISO Control Center will notify the Participating Transmission Owners by direct voice communications of the situation; and

(F) once the Backup CAISO Control Center is again available, the Primary CAISO Control Center will transfer all functions back to the Backup CAISO Control Center, and the Backup CAISO Control Center will notify all Market Participants via the CAISO’s secure communication system.

### 7.7.11 [Not Used]

### 7.7.12 [Not Used]

### 7.7.13 [Not Used]

### 7.7.14 [Not Used]

### 7.7.15 [Not Used]

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# 8. Ancillary Services

\* \* \*

## 8.3 Procurement; Certification and Testing; Contracting Period

### 8.3.1 Procurement of Ancillary Services

The CAISO shall operate competitive Day-Ahead and Real-Time Markets to procure Ancillary Services. The Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) applications used in the Integrated Forward Market (IFM) and the Real-Time Market (RTM) shall calculate optimal resource commitment, Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services Awards and Schedules at least cost to End-Use Customers consistent with maintaining System Reliability. Any Scheduling Coordinator representing resources, System Units, Participating Loads, Proxy Demand Resources or imports of System Resources may submit Bids into the CAISO’s Ancillary Services markets provided that it is in possession of a current certificate for the resources concerned. Regulation Up, Regulation Down, and Operating Reserves necessary to meet CAISO requirements not met by self-provision will be procured by the CAISO as described in this CAISO Tariff. The amount of Ancillary Services procured in the IFM is based on the CAISO Forecast of BAA Demand for the CAISO and the forecasted intertie schedules in the RTM for the Operating Hour net of (i) Self-Provided Ancillary Services from resources internal to the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and Dynamic System Resources certified to provide Ancillary Services and (ii) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The amount of additional Ancillary Services procured in the RTM is based on the CAISO Forecast of BAA Demand for the CAISO, the Day-Ahead Schedules established net interchange, and the forecast of the Intertie Schedules for the Operating Hour in the RTM net of (i) available awarded Day-Ahead Ancillary Services, (ii) Self-Provided Ancillary Services from resources internal to the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and Dynamic System Resources certified to provide Ancillary Services, and (iii) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The amount of Ancillary Services procured in the Real-Time Market is based upon the CAISO Forecast of BAA Demand for the CAISO and the net interchange for the Operating Hour from FMM Schedules net of (i) available awarded Day-Ahead Ancillary Services, (ii) Self-Provided Ancillary Services from resources internal to the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and Dynamic System Resources certified to provide Ancillary Services, (iii) additional Operating Reserves procured in the FMM, and (iv) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The CAISO may procure incremental Ancillary Services in the Real-Time Market based in part on a determination during the FMM that any Ancillary Services capacity awarded or self-provided in the Day-Ahead Market is not available as a result of a resource constraint or Transmission Constraints. Resource constraints may include but are not limited to an Outage of a resource or Ramp Rate constraints. Incremental procurement in the Real-Time Market will exclude Ancillary Services Capacity the CAISO has determined is not available.

The CAISO will manage the Energy from both CAISO-procured and Self-Provided Ancillary Services as part of the FMM and Real-Time Dispatch. In the Day-Ahead Market, the CAISO procures one-hundred (100) percent of its Ancillary Service requirements based on the Day-Ahead Demand Forecast net of Self-Provided Ancillary Services. After the Day-Ahead Market, the CAISO procures additional Ancillary Services needed to meet system requirements from all resources in the Real-Time Market. The amount of Ancillary Services procured in the Real-Time Market is based on the CAISO Forecast of BAA Demand for the CAISO for the Operating Hour net of Self-Provided Ancillary Services.

Awards of AS in the RTM to Non-Dynamic System Resources are for the entire next Operating Hour. The CAISO procurement of Ancillary Services from all other resources in the Real-Time Market is for a fifteen (15) minute FMM interval. The CAISO’s procurement of Ancillary Services from Non-Dynamic System Resources, Dynamic System Resources and internal Generation (which includes Generation from Generating Units that are Pseudo-Ties to the CAISO Balancing Authority Area) in the Real-Time Market is based on the Ancillary Service Bids submitted or generated in the RTM consistent with the requirements in Section 30. The CAISO may also procure Ancillary Services pursuant to the requirements in Section 42.1 and as permitted under the terms and conditions of a Reliability Must-Run Contract.

The CAISO will contract for long-term Voltage Support service with owners of Reliability Must-Run Units under Reliability Must-Run Contracts. These requirements and standards apply to all Ancillary Services whether self-provided or procured by the CAISO.

\* \* \*

## 8.4 Technical Requirements for Providing Ancillary Services

### 8.4.1.1 Regulation

A resource offering Regulation must have the following operating characteristics and technical capabilities:

(a) it must be capable of being controlled and monitored by the CAISO EMS by means of the installation and use of a standard CAISO direct communication and direct control system, a description of which and criteria for any temporary exemption from which, the CAISO shall publish on the CAISO Website;

(b) it must be capable of achieving at least the Ramp Rates (increase and decrease in MW/minute) stated in its Bid for the full amount of Regulation capacity offered;

(c) the Regulation capacity offered must not exceed the maximum Ramp Rate (MW/minute) of that resource times ten (10) minutes;

(d) the resource to CAISO Control Center telemetry must, in a manner meeting CAISO standards, include indications of whether the resource is on or off CAISO EMS control at the resource terminal equipment;

(e) the resource must be capable of the full range of movement within the amount of Regulation capability offered without manual resource operator intervention of any kind;

(f) each Ancillary Service Provider must ensure that its CAISO EMS control and related SCADA equipment for its resource are operational throughout the time period during which Regulation is required to be provided;

(g) Regulation capacity offered must be dispatchable on a continuous basis for at least sixty (60) minutes in the Day-Ahead Market and at least thirty (30) minutes in the Real-Time Market after issuance of the Dispatch Instruction. The CAISO will measure continuous Energy from the time a resource reaches its award capacity. In the Real-Time Market, where a storage resource using the Non-Generator Resource model will not have sufficient State of Charge to meet its Ancillary Services Schedule, Imbalance Reserves Award, or RUC Award, the CAISO will dispatch the storage resource to have sufficient State of Charge to meet its Ancillary Services Schedule, Imbalance Reserves Award, or RUC Award. Scheduling Coordinators for Non-Generator Resources located within the CAISO Balancing Authority Area that require Energy from the Real-Time Market to offer their full capacity as Regulation may request the use of Regulation Energy Management as described in Section 8.4.1.2; and

(h) Regulation capacity offered must meet or exceed the minimum performance threshold of twenty-five (25) percent measured accuracy as specified in Section 8.2.3.1.1.

\* \* \*

# 11. CAISO Settlements and Billing

## 11.1 Settlement Principles

The CAISO shall calculate, account for and settle payments and charges with Business Associates in accordance with the following principles:

(a) The CAISO shall be responsible for calculating Settlement balances for any penalty or dispute in accordance with the CAISO Tariff, and any transmission Access Charge to UDCs or MSSs and Participating TOs;

(b) The CAISO shall create and maintain computer back-up systems, including off-site storage of all necessary computer hardware, software, records and data at an alternative location that, in the event of a Settlement system breakdown at the primary location of the day-to-day operations of the CAISO, could serve as an alternative location for day-to-day Settlement operations within a reasonable period of time;

(c) The CAISO shall retain all Settlement data records for a period which, at least, allows for the re-run of data as required by this CAISO Tariff and any adjustment rules of the Local Regulatory Authority governing the Scheduling Coordinators and their End-Use Customers and FERC;

(d) The CAISO shall calculate, account for, and settle all charges and payments based on the Settlement Quality Meter Data it has received, or, if Settlement Quality Meter Data is not available, based on the best available information or estimate it has received in accordance with the provisions in Section 10 and the applicable Business Practice Manuals; and

(e) Day-Ahead Schedules, RUC Awards and AS Awards shall be settled at the relevant LMP, RUC Price, and ASMPs, respectively. FMM Schedules shall be settled at the relevant FMM LMP at the relevant Scheduling Point. FMM AS Awards shall be settled at the relevant FMM ASMP. All Dispatch Instructions shall be deemed delivered and settled at relevant Real-Time Market prices. Deviations from Dispatch Instructions shall be settled as Uninstructed Deviations.

### 11.1.1 [Not Used]

### 11.1.2 Settlement Charges and Payments

The CAISO shall settle charges and payments as specified in this Section 11.

### 11.1.3 Financial Transaction Conventions and Currency

The following conventions have been adopted in this CAISO Tariff in defining sums of money to be received by or remitted by the CAISO:

(a) The act of receiving a sum of money in accordance with this CAISO Tariff is defined as “receiving” such sum, and each use of the word “receive” or a grammatical variation thereof in the context of receiving such sum shall have the meaning consistent with this definition. The act of providing a sum of money to another entity in accordance with this CAISO Tariff is defined as “providing” or “remitting” such sum, and each use of the word “provide” or “remit” or a grammatical variation thereof in the context of providing or remitting such sum shall have the meaning consistent with this definition.

(b) Where the CAISO is to receive a sum of money in accordance with this CAISO Tariff, this is defined as a “charge” and shall be received by the CAISO on or before 10:00 a.m. on the relevant Payment Date as prescribed in the CAISO Tariff.

(c) Where the CAISO is required to pay a sum of money in accordance with this CAISO Tariff, this is defined as a “payment” and shall be remitted by the CAISO on the relevant Payment Date as prescribed in the CAISO Tariff.

(d) All financial transactions are denominated in United States dollars and cents.

(e) All payments by the CAISO to Business Associates shall be made by Fedwire or, at the option of each Business Associate, by ACH. All payments to the CAISO by Business Associates shall be made by Fedwire or, at the option of each Business Associate, by ACH.

### 11.1.4 [Not Used]

**11.1.5 [Not Used]**

## 11.2 Settlement of Day-Ahead Market Transactions

All transactions in the IFM and RUC as specified in the Day-Ahead Schedule, AS Awards and RUC Awards, respectively, are financially binding and will be settled based on the Day-Ahead LMP, ASMP or RUC Price for the relevant Location for the specific resource or transaction identified for the Bid. The CAISO will settle the costs of Demand, Energy, Imbalance Reserves, Reliability Capacity, or Ancillary Services as separate Settlement charges and payments for each Settlement Period as appropriate.

### 11.2.1 IFM Settlements

**11.2.1.1 IFM Payments for Supply of Energy and Imbalance Reserves**

For each Settlement Period for which the CAISO clears Energy transactions in the IFM, the CAISO shall pay the relevant Scheduling Coordinator for the MWh quantity of Supply of Energy from all Generating Units, Participating Loads, Proxy Demand Resources, Reliability Demand Response Resources, Distributed Energy Resource Aggregations and System Resources in an amount equal to the IFM LMP at the applicable PNode or Aggregated PNode multiplied by the MWh quantity specified in the Day-Ahead Schedule for Supply (which consists of the Day-Ahead Scheduled Energy).

For each Settlement Period for which the CAISO clears Imbalance Reserves transactions in the IFM, the CAISO pays Scheduling Coordinators representing Generating Units, Participating Loads, Proxy Demand Resources, Reliability Demand Response Resources, Distributed Energy Resource Aggregations and System Resources the product of the: (a) Locational IRU Price or Locational IRD Price at the applicable PNode or Aggregated PNode; and (b) MW quantity of the awarded IRU or IRD.

For each Settlement Period for which the CAISO clears Imbalance Reserves transactions in the IFM, the CAISO pays the congestion revenue from Transmission Constraints binding in the up and down deployment scenarios for Imbalance Reserves calculated per Section 31.3.1.6.4 to the EDAM Entity Scheduling Coordinator to distribute per the EDAM Entity’s OATT or, for the CAISO BAA, as specified in Section 11.2.4.

**11.2.1.2 IFM Charges for Demand at LAPS**

For each Settlement Period that the CAISO clears Energy transactions in the IFM, except as specified in Section 30.5.3.2 and except for Participating Loads, which shall be subject to the charges specified in 11.2.1.3, the CAISO shall charge Scheduling Coordinators for the MWh quantity of Demand scheduled at an individual LAP in the Day-Ahead Schedule, in an amount equal to the IFM LMP for the applicable LAP multiplied by the MWh quantity scheduled in the Day-Ahead Schedule at the relevant LAP. The applicable Default LAP IFM LMP is as described in Section 27.2.2. For Scheduling Coordinators whose Demand scheduled at the individual LAP is subject to an upward price correction as specified in Section 11.21, the CAISO will use the Price Correction Derived LMP to settle the MWh quantity of Demand scheduled in the Day-Ahead Schedule at the relevant LAP.

**11.2.1.3 IFM Charges for Demand by Participating Loads, Including Aggregated Participating Load**

For each Settlement Period that the CAISO clears Energy transactions in the IFM for Demand by Participating Loads, the CAISO shall charge the Scheduling Coordinators an amount equal to the MWh quantity of Demand scheduled in the Day-Ahead Schedule for the relevant Participating Load at the PNode (or Custom LAP, in the case of Aggregated Participating Load), multiplied by the IFM LMP at that PNode (or Custom LAP, in the case of Aggregated Participating Load). The Custom LAP Price is determined as described in Section 27.2.2. For Scheduling Coordinators whose Demand scheduled at the individual PNode or Custom LAP is subject to an upward price correction as specified in Section 11.21, the CAISO will use the Price Correction Derived LMP to settle the MWh quantity scheduled in the Day-Ahead Schedule for that Scheduling Coordinator at the relevant PNode or Custom LAP.

**11.2.1.4 IFM Charges for Energy Exports at Scheduling Points**

For each Settlement Period that the CAISO clears Energy transactions in the IFM, the CAISO shall charge Scheduling Coordinators for the Energy export MWh quantity at individual Scheduling Points scheduled in the Day-Ahead Schedule, an amount equal to the IFM LMP for the applicable Scheduling Point multiplied by the MWh quantity at the individual Scheduling Point scheduled in the Day-Ahead Schedule. For Scheduling Coordinators whose exports scheduled at the individual Scheduling Points is subject to an upward price correction as specified in Section 11.21, the CAISO will use the Price Correction Derived LMP to settle the MWh quantity of Energy exports scheduled in the Day-Ahead Schedule at the relevant Scheduling Point.

**11.2.1.5 IFM Congestion Credit for ETCs, TORs, and Converted Rights**

For all Points of Receipt and Points of Delivery pairs associated with a valid and balanced ETC Self-Schedule, TOR Self-Schedule or Converted Rights Self-Schedule, the CAISO shall not impose any charge or make any payment to the Scheduling Coordinator related to the MCC associated with such Self-Schedules. For each Scheduling Coordinator, the CAISO shall determine the applicable IFM Congestion Credit, which can be positive or negative, as the sum of the products of the quantity scheduled in the Day-Ahead Schedule and the MCC at each eligible Point of Receipt and Point of Delivery associated with the valid and balanced portions of that Scheduling Coordinator’s ETC, TOR, and Converted Rights Self-Schedules.

**11.2.1.6 Allocation of IFM Marginal Losses Surplus Credit**

On each Settlement Statement, the CAISO shall apply the IFM Marginal Losses Surplus Credit to each Scheduling Coordinator for the period of each Settlement Statement. For each Settlement Period, the IFM Marginal Losses Surplus Credit shall be the product of the IFM Marginal Losses Surplus rate ($/MWh) and the MWh of Measured Demand for the relevant Scheduling Coordinator net of that Scheduling Coordinator’s (1) Measured Demand associated with a TOR Self-Schedule subject to the IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules as provided in Section 11.2.1.7; and (2) Measured Demand associated with a TOR Self-Schedule subject to the RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules as provided in Section 11.5.7.2.

The IFM Marginal Losses Surplus rate shall be equal to the total IFM Marginal Losses Surplus ($) divided by the sum of the total MWh of Measured Demand in the CAISO Balancing Authority Area for the relevant Settlement Period net of (1) any Measured Demand associated with a TOR Self-Schedule subject to the IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules as provided in Section 11.2.1.7; and (2) any Measured Demand associated with a TOR Self-Schedule subject to the RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules as provided in Section 11.5.7.2.

**11.2.1.7 IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules**

For all Points of Receipt and Points of Delivery pairs associated with a valid and balanced TOR Self-Schedule submitted pursuant to an existing agreement between the TOR holder and either the CAISO or a Participating TO as specified in Section 17.3.3, the CAISO shall not impose any charge or make any payment to the Scheduling Coordinator related to the MCL associated with such TOR Self-Schedules and will instead impose any applicable losses charges as specified in the existing agreement between the TOR holder and either the CAISO or a Participating TO applicable to the relevant TOR. In any case in which the TOR holder has an existing agreement regarding its TORs with either the CAISO or a Participating TO, the provisions of the agreement shall prevail over any conflicting provisions of this Section 11.2.1.7. Where the provisions of this Section 11.2.1.7 do not conflict with the provisions of the agreement, the provisions of this Section 11.2.1.7 shall apply to the subject TORs. For each Scheduling Coordinator, the CAISO shall determine the applicable IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules, which can be positive or negative, as the sum of the products of the quantity scheduled in the Day-Ahead Schedule and the MCL at each eligible Point of Receipt and Point of Delivery associated with the valid and balanced portions of that Scheduling Coordinator’s TOR Self-Schedules.

**11.2.1.8 Charges for Unavailable Imbalance Reserves**

As provided in this Section 11.2.1.8, the CAISO charges resources with Imbalance Reserves Awards when some portion of the Imbalance Reserves Award is unavailable to the CAISO.

**11.2.1.8.1 Charges for Unavailable IRU awards**

A resource’s unavailable IRU quantity is the amount, if any, by which the resource’s Day-Ahead Schedule for Supply plus Ancillary Services Awards other than for Regulation Down plus the IRU award minus the Five-Minute Imbalance Reserve Quantity exceeds the resource’s Upper Economic Limit as adjusted by applicable Outages in the FMM. The CAISO charges a resource with an unavailable IRU quantity the product of the unavailable quantity and the highest of the RTPD Flexible Ramp Up Price, the RTD Flexible Ramp Up Price, or the resource’s Locational IRU Price.

**11.2.1.8.2 Charges for Unavailable IRD awards**

A resource’s unavailable IRD quantity is the amount, if any, by which the resource’s Lower Economic Limit as adjusted by applicable Outages in the FMM exceeds the resource’s Day-Ahead Schedule for Supply minus the Ancillary Services Awards for Regulation Down minus the IRD award plus the Five-Minute Imbalance Reserve Quantity. The CAISO charges a resource with an unavailable IRD quantity the product of the unavailable quantity and the highest of the RTPD FRD price, the RTD FRD price, or the resource’s Locational IRD Price.

**11.2.1.8.3 Priority of Charges When a Resource is Unavailable for both Imbalance Reserves and Reliability Capacity**

For Settlement Periods in which a resource receives both a RUC Award and Imbalance Reserves Award and is unavailable in the RTM, or only bids a portion of its combined award, the CAISO first applies charges per Section 11.2.2.2 to the quantity of unavailable Reliability Capacity and then applies charges per this Section 11.2.1.8 to the remaining unavailable capacity. If a resource has an Ancillary Services Award, RUC Award, and Imbalance Reserves Award in the same Settlement Period and is unavailable in the RTM, then the CAISO first applies the rescission rules in Section 11.10.9 before determining any unavailable quantities pursuant to this Section 11.2.1.8.3.

**11.2.1.9 Allocation of Imbalance Reserves Costs** The CAISO allocates the separate costs of IRU and IRD through distinct two-tiered allocations. For IRU, the costs allocated include the direct costs of procuring IRU, as reflected by the summation of the product of each Imbalance Reserves Award for IRU and its Locational IRU Price, and the congestion revenue calculated per Section 31.3.1.6.4 from transmission constraints binding in the up deployment scenario for imbalance reserves. For IRD, the costs allocated include both the direct costs, as reflected by the summation of the product of each Imbalance Reserves Award for IRD and its Locational IRD Price, of procuring IRD and the congestion revenue calculated per Section 31.3.1.6.4 from transmission constraints binding in the down deployment scenario for imbalance reserves.

A Scheduling Coordinator’s allocation of IRU costs in tier 1 is the product of its IRU tier 1 cost allocation quantity, as specified in Section 11.2.1.9.1, and its IRU tier 1 cost allocation price, as specified in Section 11.2.1.9.3. A Scheduling Coordinator’s allocation of IRD costs in tier 1 is the product of its IRD tier 1 cost allocation quantity, as specified in Section 11.2.1.9.2, and its IRD tier 1 cost allocation price, as specified in Section 11.2.1.9.4.

The CAISO allocates the costs of Imbalance Reserves procurement not recovered through the IRU or IRD tier 1 cost allocations to Scheduling Coordinators in Tier 2 in proportion to their metered Demand in the interval for which the CAISO procured the Imbalance Reserves. For ETC and TOR self-schedules, the CAISO treats quantities above the valid and balanced portion as metered Demand subject to cost allocation in Tier 2.

**11.2.1.9.1 IRU Tier 1 Cost Allocation Quantity**

A Scheduling Coordinator’s total IRU tier 1 cost allocation quantity is the sum of the tier 1 quantities for the entities it represents specified as follows.

The IRU tier 1 cost allocation quantity for Generating Units, Participating Loads, Proxy Demand Resources, Reliability Demand Response Resources, Distributed Energy Resource Aggregations and System Resources that are not scheduled as a Wheeling Through transaction is the higher of: (a) zero; and (b) the difference between the Energy portion of the Day-Ahead Schedule and the FMM Upper Economic Limit (as adjusted by Outages, a reduction in VER forecast from the Day-Ahead Market to FMM, or the E-Tag transmission profile consumed by the Real-Time Market).

For non-Participating Load, the IRU tier 1 cost allocation quantity is its negative Uninstructed Imbalance Energy quantity, if any.

The IRU tier 1 cost allocation quantity for an entity exporting Energy [, excluding wheel through transactions] is the higher of: (a) zero; and (b) the difference between the FMM self-schedule and Energy portion of the Day-Ahead Schedule.

**11.2.1.9.2 IRD Tier 1 Cost Allocation Quantity**

A Scheduling Coordinator’s total IRD tier 1 cost allocation quantity is the sum of the tier 1 quantities for the entities it represents, specified as follows.

The IRU tier 1 cost allocation quantity for Generating Units, Participating Loads, Proxy Demand Resources, Reliability Demand Response Resources, Distributed Energy Resource Aggregations and System Resources that are not scheduled as a Wheeling Through transaction is the higher of: (a) zero; and (b) the difference between the FMM Lower Economic Limit (as adjusted by Outages, a reduction in VER forecast from the Day-Ahead Market to FMM, or the E-Tag transmission profile consumed by the Real-Time Market) and the Energy portion of the Day-Ahead Schedule

For non-Participating Load, the IRD tier 1 cost allocation quantity is its positive Uninstructed Imbalance Energy quantity, if any.

The IRD tier 1 cost allocation quantity for an entity exporting Energy from the CAISO Balancing Authority Area is the higher of: (a) zero; and (b) the difference between the Energy portion of the Day-Ahead Schedule and the E-Tag transmission profile consumed by the Real-Time Market).

**11.2.1.9.3 IRU Tier 1 Cost Allocation Price**

The IRU tier 1 cost allocation price in an interval is the lower of: (a) the total IRU cost, as adjusted by charges assessed per Section 11.2.1.8.1, divided by the total MWs of IRU procured; and (b) the total IRU cost, as adjusted by charges assessed per Section 11.2.1.8.1, divided by the total IRU tier 1 allocation quantity.

**11.2.1.9.4 IRD Tier 1 Cost Allocation Price**

The IRD tier 1 cost allocation price in an interval is the lower of: (a) the total IRD cost, as adjusted by charges assessed per Section 11.2.1.8.2, divided by the total MWs of IRD procured; and (b) the total IRD cost, as adjusted by charges assessed per Section 11.2.1.8.2, divided by the total IRD tier 1 allocation quantity.

**11.2.1.9.5 Imbalance Reserves Cost Allocation to MSSs**

The CAISO allocates costs of Imbalance Reserves to a MSS in the same fashion as any other Scheduling Coordinator irrespective of the MSS’s election, per Section 4.9.13, of net Settlements or gross Settlements.

The CAISO allocates costs of Imbalance Reserves to a MSS that has elected, per Section 4.9.13, to Load follow with its generating resources based on the MSS’s net portfolio uninstructed deviations in tier 1 and tier 2 of the IRU and IRD cost allocation based on the MSS’s net portfolio uninstructed deviations.

### 11.2.2 Calculation of Hourly RUC Compensation

For each Settlement Period and resource, Scheduling Coordinators shall receive RUC Compensation, which is the sum of the RUC Availability Payment as determined pursuant to Section 11.2.2.1 and the RUC Bid Cost Recovery amount as determined in Section 11.8.3.

**11.2.2.1 Settlement of RUC Availability Payment**

Scheduling Coordinators shall receive RUC Availability Payments for all eligible capacity awarded in the RUC process. RMR Capacity is not eligible for RUC Availability Payments in the DAM. The RUC Availability Payment shall be calculated for each resource as the product of the RCU Availability Quantity and the RUC Price for RCU or the product of the RCD Availability Quantity and the RUC Price for RCD. The RUC Availability Payment amounts are allocated through the RUC Compensation Costs allocation in Section 11.8.6.5.

The CAISO provides a RUC Availability Payment to a Scheduling Coordinator for a MSS the same as any other Scheduling Coordinator irrespective of the MSS’s election, per Section 4.9.13, of net Settlements or gross Settlements.

**11.2.2.2 Rescission of RUC Availability Payment**

Rescission of all or a portion of the RUC Availability Payment for a resource as defined in Section 31.5.7 shall be settled in accordance with this Section 11.2.2.2.

**11.2.2.2.1 Undispatchable RUC Capacity**

The CAISO rescinds the RUC Availability Payment in a Settlement Interval for Undispatchable Capacity related to Reliability Capacity.

In a settlement interval, a Generating Unit, Participating Load, Proxy Demand Resource, System Unit or System Resource has Undispatchable Capacity for RCU to the extent the Energy portion of the Day-Ahead Schedule plus Ancillary Services Awards other than for Regulation Down plus the IRU award plus the RCU award exceeds the lower of the resource’s Upper Economic Limit or upper operating limit.

In a settlement interval, a Generating Unit, Participating Load, Proxy Demand Resource, System Unit or System Resource has Undispatchable Capacity for RCD to the extent the resource’s Lower Economic Limit exceeds the Energy portion of the Day-Ahead Schedule minus the Ancillary Services Awards for Regulation Down minus the IRD award minus the RCD award.

The CAISO evaluates a Multi-Stage Generating Resource for Undispatchable Capacity related to Reliability Capacity for the entire Generating Unit and not for the MSG Configuration.

**11.2.2.2.2 [Not Used]**

**11.2.2.2.3 Allocation of Rescinded RUC Availability Payments Due to Non-Performance**

RUC Availability Payments rescinded due to non-performance are subtracted from the RUC Compensation Costs allocated per Section 11.8.6.5.3.

### 11.2.3 IFM Energy Charges and Payments for Metered Subsystems

**11.2.3.1 Gross Energy Settlement for Metered Subsystems**

For Scheduling Coordinators that submit Bids for MSS Operators that have selected gross Energy Settlement, CAISO shall settle Energy, the MSS Demand and MSS Supply, in the Day-Ahead Schedules pursuant to Section 11.2.3.1.1 and 11.2.3.1.2.

**11.2.3.1.1 IFM Charges for MSS Demand under Gross Energy Settlement**

The CAISO shall charge Scheduling Coordinators that submit Bids for MSS Operators that have selected or are subject to gross Energy Settlement an amount equal to the product of the MWh quantity of Demand internal to the MSS in its Day-Ahead Schedule at the price at the Default LAP where the MSS LAP is located.

**11.2.3.1.2 IFM Payments for MSS Supply under Gross Energy Settlement**

The CAISO shall pay Scheduling Coordinators that submit Bids for MSS Operators that have selected or are subject to gross Energy Settlement an amount equal to the product of the MWh quantity of Supply from the MSS in its Day-Ahead Schedule at the corresponding PNode and the applicable IFM LMP.

**11.2.3.1.3 IFM Payments for MSSs providing Imbalance Reserves**

A MSS that receives an Imbalance Reserves Award will be settled per Section 11.2.1.1 irrespective of that MSS’s election under Section 4.9.13 of net or gross settlement.

**11.2.3.2 Net Energy Settlement for Metered Subsystems**

For Scheduling Coordinators that submit Bids for MSS Operators that have selected net Energy Settlement, the CAISO shall settle the net MSS Demand and MSS Supply in the Day-Ahead Schedules pursuant to Section 11.2.3.2.1 and 11.2.3.2.2.

**11.2.3.2.1 IFM Charges for MSS Demand under Net Energy Settlement**

The CAISO shall charge Scheduling Coordinators that submit Bids for MSS Operators that have selected net Energy Settlement an amount equal to the product of the net MSS Demand in the Day-Ahead Schedule and the IFM MSS Price. The net MSS Demand is the quantity of MSS Demand that exceeds MSS Generation for the applicable MSS.

**11.2.3.2.2 IFM Payment for MSS Supply under Net Energy Settlement**

The CAISO shall pay Scheduling Coordinators that submit Bids for MSS Operators that have selected net Energy Settlement an amount equal to the product of the net MSS Supply in the Day-Ahead Schedule and the weighted average price of all IFM LMPs for all applicable PNodes within the relevant MSS. The net MSS Supply is the quantity of MSS Generation that exceeds the MSS Demand for the applicable MSS. The weights used to compute the weighted average LMPs shall be equal to MSS Generation scheduled in the Day-Ahead Schedule.

### 11.2.4 CRR Settlements

The CAISO will pay or charge CRR Holders as further specified in this Section 11.2.4 and its subsections.

**11.2.4.1 Calculation of the IFM Congestion Charge**

For each Settlement Period of the IFM, the CAISO will calculate the IFM Congestion Charge as the IFM MCC amount for all scheduled Demand and Virtual Demand Awards, minus the IFM MCC amount for all scheduled Supply and Virtual Supply Awards.

The IFM MCC amount for all scheduled Demand and Virtual Demand Awards is the sum of part (a), part (b), and part (c) of this Section 11.2.4.1.

The IFM MCC amount for all scheduled Supply and Virtual Supply Awards is the sum of part (d), part (e) and part (f) of this Section 11.2.4.1.

Part (a) is the sum of the products of the IFM MCC of Energy and the total MWh of Demand scheduled in the Day-Ahead Schedule and Virtual Demand Awards at all the applicable PNodes and Aggregated Pricing Nodes for the Settlement Period.

Part (b) is the sum of the products of the MCC for the Locational IRU Price and the nodally distributed Upward Imbalance Reserves Requirement specified in Section 31.3.1.6.3.2, as adjusted by any procurement relaxation specified in Section 31.3.1.6.2.

Part (c) is the sum of the products of the MCC for the Locational IRD Price and the nodally distributed Downward Imbalance Reserves Requirement specified in Section 31.3.1.6.3.2, as adjusted by any procurement relaxation specified in Section 31.3.1.6.2.Part (d) is the sum of the products of the IFM MCC and the total of the MWh of Supply scheduled in the Day-Ahead Schedule and the Virtual Supply Awards at all the applicable PNodes for the Settlement Period.

Part (e) is the sum of the products of the MCC for the Locational IRU Price and the IRU Awards.

Part (f) is the sum of the products of the MCC for the Locational IRD Price and the IRD Awards. **11.2.4.1.1 [Not Used]**

**11.2.4.1.2 Calculation of Hourly CRR Congestion Fund**

The CAISO calculates an Hourly CRR Congestion Fund for every Transmission Constraint that is congested in the IFM in a Settlement Period. The Hourly CRR Congestion Fund specific to a particular binding Transmission Constraint in a given Settlement Period is the sum of the: (a) portion of the IFM Congestion Charge in that Settlement Period attributable to congestion on the Transmission Constraint to which the Hourly CRR Congestion Fund corresponds; (b) charges specific to the Transmission Constraint calculated pursuant to Section 11.2.4.4.1; and (c) CRR revenue adjustments the CAISO may make pursuant to Sections 11.2.4.6 or 11.2.4.7 that are associated with the Transmission Constraint.

**11.2.4.2 Settlement Calculation for the Different CRR Types**

For the purposes of settling the various CRR Types, the CAISO will calculate the Settlement of CRRs as described in this Section 11.2.4.2. When a CRR Source or CRR Sink is a LAP, the CAISO will use the Load Distribution Factors used in the IFM to produce the LAP Price at which it will settle the CRR. When a CRR Source or CRR Sink is a Trading Hub, the CAISO will use the weighting factors used in the IFM, and in the CRR Allocation and CRR Auction processes, to produce the Trading Hub prices that it will use to settle the various CRR Types.

**11.2.4.2.1 [Not Used]**

**11.2.4.2.2 [Not Used]**

**11.2.4.3 Payments and Charges for Monthly and Annual Auctions**

The CAISO will charge CRR Holders for the Market Clearing Price for CRRs obtained through the clearing of the CRR Auction as described in Section 36.13.6. To the extent the CRR Holder purchases a CRR through a CRR Auction that has a negative value, the CAISO will retain the CRR Auction proceeds and apply them to credit requirements of the applicable CRR Holder, in accordance with Section 12.6.3 of the CAISO Tariff. The CAISO will net all revenue received and payments made through this process. CRR Auction net revenue amounts for on-peak and off-peak usage from each CRR Auction will be separated. The CAISO will allocate CRR Auction revenues for each season coming from the annual auction uniformly across the three months comprising each season based on time of use. The CAISO will then add these on-peak and off-peak monthly amounts from the seasonal auctions to the corresponding monthly on-peak and off-peak amounts from the monthly CRR Auction for the same month to form the monthly net CRR Auction on-peak and off-peak revenues, respectively. Furthermore, the CAISO will convert these monthly net CRR Auction revenues into daily values and add them to the daily CRR Balancing Account. In particular, the daily CRR Balancing Account contribution will be the sum of: (1) the monthly net CRR Auction on-peak amount multiplied by the ratio of daily on-peak hours to monthly on-peak hours; and (2) the monthly net CRR Auction off-peak amount multiplied by the ratio of daily off-peak hours to monthly off-peak hours.

**11.2.4.4 Hourly CRR Calculations, Daily CRR Settlement, and Potential Monthly Surplus Distribution Payments**

**11.2.4.4.1 Calculating CRR Holders’ Congestion-Supported Values**

For each Settlement Period, the CAISO uses the funds in the Hourly Congestion Funds calculated in Section 11.2.4.1.2 to determine the Congestion-Supported Values paid and charged to CRR Holders, by first determining all Net Modeled CRR Flow quantities. The CAISO then determines whether the Net Modeled CRR Flow results in a payment or charge to the CRR Holder.

For a CRR Holder whose Net Modeled CRR Flow over a binding Transmission Constraint is in the prevailing direction, the Congestion-Supported Value is a payment equal to the ratio of that CRR Holder’s prevailing Net Modeled CRR Flow over that Transmission Constraint (accounting for revenue adjustments made pursuant to Sections 11.2.4.6 or 11.2.4.7), as compared to the sum of all CRR Holders’ prevailing Net Modeled CRR Flow over that Transmission Constraint (accounting for revenue adjustments made pursuant to Sections 11.2.4.6 or 11.2.4.7). The CAISO will not pay a CRR Holder from an Hourly CRR Congestion Fund in excess of the CRR Holder’s Net Modeled CRR Flow multiplied by the Shadow Price of that binding Transmission Constraint, minus any revenue adjustments made pursuant to Sections 11.2.4.6 or 11.2.4.7 that are allocated to that Transmission Constraint.

For a CRR Holder whose Net Modeled CRR Flow over a binding Transmission Constraint is in the counter-flow direction, the Congestion-Supported Value is a charge equal to the Net Modeled CRR Flow multiplied by the Shadow Price of that binding Transmission Constraint.

The lower bound of the sum of Congestion-Supported Values for a CRR Option across the Settlement Periods of a day is zero.

The CAISO transfers any funds in an Hourly CRR Congestion Fund associated with binding Transmission Constraints to which no CRR has a positive or negative difference between the source and sink PTDFs to the CRR Balancing Account.

Any funds remaining in an Hourly CRR Congestion Fund after all funds have been allocated to CRRs or transferred to the CRR Balancing Account for that hour are reserved for potential Daily CRR Surplus Distribution Payments or Monthly CRR Surplus Distribution Payments to CRR Holders. The funds the CAISO holds in reserve for a CRR Holder pertaining to a Transmission Constraint are held in proportion to that CRR Holder’s Net Modeled CRR Flow in that Settlement Period (accounting for revenue adjustments made pursuant to Sections 11.2.4.6 or 11.2.4.7) relative to the Net Modeled CRR Flow over that Transmission Constraint for all CRR Holders in that Settlement Period (accounting for revenue adjustments made pursuant to Sections 11.2.4.6 or 11.2.4.7).

**11.2.4.4.2 Calculating Daily CRR Surplus Payments**

The CAISO allocates the funds in a Daily Congestion Fund as a Daily CRR Surplus Distribution Payment to CRR Holders that have funds reserved for them in a Daily CRR Congestion Fund pursuant to Section 11.2.4.4.1, and whose total Congestion-Supported Values pertaining to that Transmission Constraint during the day are less than the sum of the Net Modeled CRR Flow multiplied by the Shadow Price of that binding Transmission Constraint across the day (accounting for revenue adjustments made pursuant to Sections 11.2.4.6 or 11.2.4.7). A Daily CRR Surplus Distribution Payments specific to a CRR Holder and Transmission Constraint cannot exceed the sum of the Net Modeled CRR Flow multiplied by the Shadow Price of that binding Transmission Constraint across all Settlement Periods of the day (account for revenue adjustments made pursuant to Sections 11.2.4.6 or 11.2.4.7). The CAISO adds any funds remaining in a Daily CRR Congestion Fund after it has made all necessary Daily CRR Surplus Distribution Payments to that Transmission Constraint’s Monthly CRR Congestion Fund.

**11.2.4.4.3 Monthly Clearing of the Monthly Constraint-Specific CRR Congestion Fund**

The CAISO distributes the total of the Monthly CRR Congestion Fund at the end of each month.

The CAISO first distributes the funds in a Monthly CRR Congestion Fund as Monthly CRR Surplus Distribution Payments to CRR Holders that have funds reserved for them in a Monthly CRR Congestion Fund pursuant to Section 11.2.4.4.1 and whose total Congestion-Supported Values pertaining to that Transmission Constraint during the month, plus the Daily CRR Surplus Distribution Payments, are less than the sum of the Net Modeled CRR Flow multiplied by the Shadow Price of that binding Transmission Constraint across all Settlement Periods of the month (accounting for revenue adjustments made pursuant to Sections 11.2.4.6 or 11.2.4.7).

The CAISO distributes any funds remaining in a Monthly CRR Congestion Fund after it has made all required Monthly CRR Surplus Distribution Payments to Scheduling Coordinators in an amount equal to: (a) the funds in the Monthly CRR Congestion Fund, multiplied by (b) the ratio of each Scheduling Coordinator’s Measured Demand for the relevant Trading Month (net of the Scheduling Coordinator’s Measured Demand associated with valid and balanced ETC or TOR Self-Schedule quantities, which IFM Congestion Credits and/or RTM Congestion Credits were provided in the same relevant Trading Month), divided by (c) the total Measured Demand for all Scheduling Coordinators for the relevant Trading Month (net of the total Measured Demand associated with valid and balanced ETC or TOR Self-Schedule quantities, which IFM Congestion Credits and/or RTM Congestion Credits were provided in the same relevant Trading Month).

**11.2.4.5 CRR Balancing Account**

**11.2.4.5.1 Accumulation of CRR Balancing Account Funds**

The CAISO will accumulate the daily CRR Balancing Account: (1) seasonal and monthly CRR Auction revenues as described in Section 11.2.4.3; (2) any funds in an Hourly CRR Congestion Fund associated with binding Transmission Constraints to which no CRR has a positive or negative difference between the source and sink PTDF; (3) any IFM Congestion Charges associated with Day-Ahead Ancillary Services Awards as provided in Section 11.10.1.1.1; and (4) IFM Congestion Fund Credits as specified in Section 11.2.1.5.

**11.2.4.5.2 Distribution of CRR Balancing Account Funds**

The CAISO distributes the CRR Balancing Account to Scheduling Coordinators in an amount equal to: (a) the funds in the CRR Balancing Account, multiplied by (b) the ratio of each Scheduling Coordinator’s Measured Demand for the relevant Trading Day (net of the Scheduling Coordinator’s Measured Demand associated with valid and balanced ETC or TOR Self-Schedule quantities, which IFM Congestion Credits and/or RTM Congestion Credits were provided in the same relevant Trading Day), divided by (c) the total Measured Demand for all Scheduling Coordinators for the relevant Trading Day (net of the total Measured Demand associated with valid and balanced ETC or TOR Self-Schedule quantities, which IFM Congestion Credits and/or RTM Congestion Credits were provided in the same relevant Trading Day).

**11.2.4.5.3 Interest on CRR Balancing Account**

Interest accruing due to the CRR Balancing Account will be at the CAISO’s received interest rate and will be credited to each monthly CRR Balancing Account accrued interest fund, which is then allocated to monthly Measured Demand excluding Measured Demand associated with valid and balanced ETC, TOR, or Converted Rights Self-Schedule quantities, which IFM Congestion Credits and/or RTM Congestion Credits were provided in the same month.

**11.2.4.6 Adjustment of CRR Revenue Related to Virtual Awards**

In accordance with this Section 11.2.4.6, the CAISO will adjust the revenue from the CRRs of a CRR Holder that is also a Convergence Bidding Entity whenever either of the following creates a significant impact on the value of the CRRs held by that entity: the CRR Holder/Convergence Bidding Entity submits Virtual Bids; or the CRR Holder/Convergence Bidding Entity reduces in the RTM an import or export awarded in a Day-Ahead Schedule. As set forth in Section 11.32, the CAISO will also adjust the revenue from the CRRs of a CRR Holder (regardless of whether the CRR Holder is also a Convergence Bidding Entity) where the Scheduling Coordinator representing that CRR Holder reduces in the RTM an import or export awarded in a Day-Ahead Schedule.

(a) For purposes of this Section 11.2.4.6 and the definition of Flow Impact, a reduction by a Scheduling Coordinator submitting Schedules on behalf of an entity that is a CRR Holder to an import or export Schedule in the RTM will be treated as a Virtual Award if the segment of Economic Bids (but not Self-Schedule) leading to the Schedule reduction is: at an Energy Bid price greater than the Day-Ahead Market LMP at the relevant intertie, in the case of an import; or at any Energy Bid price less than the Day-Ahead Market LMP at the relevant intertie, in the case of an export.

In addition, if the RTM Bid does not include the full MW quantity of the Day-Ahead Schedule through some combination of Economic Bid and Self-Schedule, then the MW range not covered by the RTM Bid that was included in the Day-Ahead Schedule will be treated as a Virtual Award.

For each CRR Holder subject to this Section 11.2.4.6, for each hour, and for each Transmission Constraint binding in the IFM or FMM the CAISO will calculate the Flow Impact of the Virtual Awards awarded to the Scheduling Coordinator that represents the CRR Holder. For the purposes of calculating the CRR adjustments as specified in this Section 11.2.4.6, the CAISO will include nodal MW constraints that the CAISO applies to Eligible PNodes in the IFM pursuant to Section 30.10.

(b) The CAISO will determine the peak and off-peak hours of the day where Congestion on the Transmission Constraint was significantly impacted by the Virtual Awards awarded to the Scheduling Coordinator that represents the CRR Holder. Congestion on the Transmission Constraint will be deemed to have been significantly impacted by the Virtual Awards awarded to the Scheduling Coordinator that represents the CRR Holder if the Flow Impact passes two criteria. First, the Flow Impact must be in the direction to increase the sum of the CRR Holder’s Notional CRR Values in their portfolio in that Settlement Period. Second, the Flow Impact must exceed the threshold percentage of the flow limit for the Transmission Constraint. The threshold percentage is ten (10) percent of the flow limit for each Transmission Constraint.

(c) For each peak or off-peak hour that passes both criteria in Section 11.2.4.6(b), the CAISO will compare the Transmission Constraint’s impact on the Day-Ahead Market value of the CRR Holder’s CRR portfolio with the Transmission Constraint’s impact on the FMM value of the CRR Holder’s CRR portfolio, as applicable.

(d) The CAISO will adjust the peak or off-peak period revenue from the CRR Holder’s CRRs in the event that, over the peak or off-peak period of a day, the Transmission Constraint’s contribution to the Day-Ahead Market value of the CRR Holder’s CRR portfolio exceeds the Transmission Constraint’s contribution to the FMM value of the CRR Holder’s CRR portfolio, as applicable. The amount of the peak period adjustment will be the amount that the Transmission Constraint’s contribution to the Day-Ahead Market value of the CRR Holder’s CRR portfolio exceeds the Transmission Constraint’s contribution to the FMM value of the CRR Holder’s CRR portfolio for the peak-period hours that passed both criteria in Section 11.2.4.6(b), as applicable. The amount of the off-peak period adjustment will be the amount that the Transmission Constraint’s contribution to the Day-Ahead Market value of the CRR Holder’s CRR portfolio exceeds the Transmission Constraint’s contribution to the FMM value of the CRR Holder’s CRR portfolio for the off-peak period hours that passed both criteria in Section 11.2.4.6(b), as applicable.

The CAISO includes all adjustments of CRR revenue calculated pursuant to this Section 11.2.4.6 in the Hourly CRR Congestion Fund for the applicable Transmission Constraint corresponding to the CRR payments that would have been made but for the revenue adjustments as specified in Section 11.2.4.1.2.

**11.2.4.7 Adjustment of CRR Revenue Related to Schedules that Source and Sink in the Same Balancing Authority Area**

The CAISO will adjust the revenue from the CRRs of a CRR Holder where the Scheduling Coordinator representing that CRR Holder has submitted Bids (including Self-Schedules), in violation of Section 30.5.5 and the resulting Schedule(s) impacts the value of the CRRs in the DAM held by that CRR Holder. Such adjustment will occur if the following circumstances are all met:

(a) A portion of the E-Tag that uses the CAISO Controlled Grid relates to a Schedule in the Day-Ahead Market;

(b) The scheduled MW on the portion of the E-Tag using the CAISO Controlled Grid has a positive PTDF on a congested transmission element, where that congestion is measured in the direction of the CRR; and

(c) The CRR Holder would receive payments from CRRs on the congested transmission element.

If such circumstances occur, the CAISO adjusts the CRR revenue in that Settlement Period sot that the additional net CRR revenue that otherwise would be earned from the congestion created by the Schedule that results from the Bids submitted in violation of Section 30.5.5 is not paid to the CRR Holder. Instead, the CAISO will add those funds to the Hourly CRR Congestion Fund for the applicable Transmission Constraint.

### 11.2.5 Payment by OBAALSE for CRRs Through CRR Allocation Process

**11.2.5.1** Pursuant to Section 36.9, in addition to other requirements specified therein, an OBAALSE will be eligible to participate in the CRR Allocation process if such entity has made a pre-payment to the CAISO and has met the requirements in Section 36.9. The prepayment amount shall equal the MW of CRR requested times the Wheeling Access Charge associated with the Scheduling Point corresponding to the CRR Sink times the number of hours in the period for each requested CRR MW amount. Except as provided in Section 36.9.2, such prepayment will be made three (3) Business Days in advance of the submission of CRR nominations for Monthly CRRs, Seasonal CRRs and Long Term CRRs to the CRR Allocation. Within thirty (30) days following the completion of the CRR Allocation process for Monthly CRRs, Seasonal CRRs and Long Term CRRs, the CAISO shall reimburse such OBAALSE the amount of money pre-paid for any CRRs that were not allocated to the entity.

**11.2.5.2 Annual Repayment Option**

For entities that are eligible and elect for the annual prepayment pursuant to Section 36.9.2, the annual prepayment will be due three (3) Business Days in advance of the submission of CRR nominations for Tier LT in the CRR Allocation process. For allocated Long Term CRRs, each of the nine subsequent annual payments must be made at the beginning of the annual CRR Allocation process for the following year.

**11.2.5.3 Monthly Prepayment Option**

If the OBAALSE qualified for the monthly prepayment option as specified in Section 36.9.2, the OBAALSE shall make its payments consistent with the monthly prepayment schedule specified in the applicable Business Practice Manual.

**11.2.5.4 Treatment of Prepaid WAC Amounts**

For the amount of CRRs that were allocated to the entity, the CAISO will exempt the Scheduling Coordinator for such entity from the WAC for any Real-Time Interchange Export Schedules at the Scheduling Point corresponding to the sink of each allocated CRR, on an hourly basis for the period for which the CRR is defined, until the pre-paid funds are exhausted. At the end of the period for which the CRR is defined any remaining balance will be allocated to the Participating TOs in accordance with Section 26.1.4.3. To the extent the pre-paid balance amount is exhausted prior to the end of the duration of the awarded CRR, the Scheduling Coordinator designated by the CRR Holder that has been allocated CRRs pursuant to Section 36.9 will be charged for the WAC in accordance with Section 26.1.4.

**11.2.6 DAME Transition Period**

**11.2.6.1 Opting In to DAME Transitional Measures**

The CAISO applies DAME Transitional Measures to RA Capacity and Flexible RA Capacity provided from Resource Adequacy Resources if the CAISO receives notice, in the form and manner specified in the Business Practice Manual, from both the resource’s Scheduling Coordinator and the LSE’s Scheduling Coordinator that they mutually elect for the CAISO to apply DAME Transitional Measures to the RA Capacity and Flexible RA Capacity the resource provides on behalf of the LSE.

An election for DAME Transitional Measures is tied to a specific resource/LSE pair and applies to all RA Capacity and Flexible RA Capacity shown on behalf of the LSE on a monthly Supply Plan for the resource submitted during the DAME Transition Period. The same resource may be part of multiple resource/LSE pairs subject to DAME Transitional Measures

Scheduling Coordinators for resources and LSEs must complete the DAME Transitional Measures election process no later than thirty (30) days after the effective date of this Section 11.2.6. The CAISO will not apply DAME Transitional Measures to resources for which the election process is not complete by this deadline. Upon mutual consent of the Scheduling Coordinator for both the resource and LSE, a resource/LSE pair may end application of DAME Transitional Measures before the end of the DAME Transition Period but is not permitted to re-elect for the CAISO to apply DAME Transitional Measures after that point.

**11.2.6.2 Calculating Quantity of Overlapping Capacity in a Settlement Period**

As specified in this Section 11.2.6.2, the CAISO determines in each Settlement Period how much of the RA Capacity and Flexible RA Capacity subject to DAME Transitional Measures overlaps separately with the subject resource’s Imbalance Reserves Award for IRU, RUC Award for RCU, Imbalance Reserves Award for IRD, and RUC Award for RCD.

 **11.2.6.2.1 Overlapping Capacity for IRU**

The quantity of overlapping IRU is the lower of the: (1) Imbalance Reserves Award for IRU; or (2) higher of the RA Capacity or Flexible RA Capacity shown on that resource’s monthly Supply Plan minus the Energy Schedule minus the Ancillary Services Awards other than for Regulation Down. Provided, however, that the quantity of overlapping IRU cannot be less than zero.**11.2.6.2.2 Overlapping Capacity for RCU**

The quantity of overlapping RCU is the lower of the: (1) RUC Award for RCU; or (2) higher of the RA Capacity or Flexible RA Capacity shown on that resource’s monthly Supply Plan minus the Energy Schedule minus the Ancillary Services Awards other than for Regulation Down minus the Imbalance Reserves Award for IRU. Provided, however, that the quantity of overlapping RCU cannot be less than zero.

**11.2.6.2.3 Overlapping Capacity for IRD**

The quantity of overlapping IRD is the lower of the: (1) Imbalance Reserves Award for IRD; or (2) Energy Schedule minus the higher of the RA Capacity or Flexible RA Capacity shown on that resource’s monthly Supply Plan. Provided, however, that the quantity of overlapping IRD cannot be less than zero.

**11.2.6.2.4 Overlapping Capacity for RCD**

The quantity of overlapping RCD is the lower of the: (1) RUC Award for RCD; or (2) Energy Schedule minus the Imbalance Reserves Award for IRD minus the higher of the RA Capacity or Flexible RA Capacity shown on that resource’s monthly Supply Plan. Provided, however, that the quantity of overlapping RCD cannot be less than zero.

**11.2.6.3 Settlement of Overlapping Capacity Subject to DAME Transitional Measures**

**11.2.6.3.1 Settlement of Overlapping IRU**

The CAISO allocates the revenue from the overlapping IRU, calculated as the product of the quantity of overlapping IRU and the applicable Locational IRU Price, partially to the Scheduling Coordinator for the LSE and partially to the Scheduling Coordinator for the resource.

The CAISO allocates the opportunity cost component of that revenue, calculated as the integral of the positive difference between the Energy LMP and the Energy Bid over the capacity range of the overlapping IRU, to the Scheduling Coordinator for the resource.

The CAISO allocates the balance of the revenue from the overlapping IRU to the Scheduling Coordinator for the LSE. If the resource is part of multiple resource/LSE pairs subject to DAME Transitional Measures, then the CAISO allocates that balance of the revenue to the LSEs in proportion to the higher of each LSE’s RA Capacity or Flexible RA Capacity obligation met by that resource.

**11.2.6.3.2 Settlement of Overlapping RCU**

The CAISO allocates the revenue from the overlapping RCU, calculated as the product of the quantity of overlapping RCU and the applicable RUC Price for RCU, to the Scheduling Coordinator for the LSE.

If the resource is part of multiple resource/LSE pairs subject to DAME Transitional Measures, then the CAISO allocates that revenue to the LSEs in proportion to the higher of each LSE’s RA Capacity or Flexible RA Capacity obligation met by that resource.

**11.2.6.3.3 Settlement of Overlapping IRD**

The CAISO allocates the revenue from the overlapping IRD, calculated as the product of the quantity of overlapping IRD and the applicable Locational IRD Price, partially to the Scheduling Coordinator for the LSE and partially to the Scheduling Coordinator for the resource.

The CAISO allocates the opportunity cost component of that revenue, calculated as the integral of the positive difference between the Energy Bid over the capacity range of the overlapping IRD and the Energy LMP, to the Scheduling Coordinator for the resource.

The CAISO allocates the balance of the revenue from the overlapping IRD to the Scheduling Coordinator for the LSE. If the resource is part of multiple resource/LSE pairs subject to DAME Transitional Measures, then the CAISO allocates that balance of the revenue to the LSEs in proportion to the higher of each LSE’s RA Capacity or Flexible RA Capacity obligation met by that resource.

**11.2.6.3.4 Settlement of Overlapping RCD**

The CAISO allocates the revenue from the overlapping RCD, calculated as the product of the quantity of overlapping RCD and the applicable RUC Price for RCD, to the Scheduling Coordinator for the LSE.

If the resource is part of multiple resource/LSE pairs subject to DAME Transitional Measures, then the CAISO allocates that revenue to the LSEs in proportion to the higher of each LSE’s RA Capacity or Flexible RA Capacity obligation met by that resource.

**11.2.6.4 Information Provision for RA Capacity Not Subject to DAME Transitional**

**Measures**

## For RA Capacity and Flexible RA Capacity not subject to DAME Transitional Measures, the CAISO provides the Scheduling Coordinator for LSEs whose RA and Flexible RA obligations are met with that capacity information regarding the opportunity costs described in Section 11.2.6.3.1 and 11.2.6.3.3.11.3 Settlement of Virtual Awards

### 11.3.1 Virtual Supply Awards

The CAISO will pay each Scheduling Coordinator with Virtual Supply Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the Day-Ahead LMP at the Eligible PNode or Eligible Aggregated PNode multiplied by the MWhs of Virtual Supply Awards. Virtual Supply Awards subject to price correction will be settled as specified in Section 11.21.

The CAISO will charge each Scheduling Coordinator with Virtual Supply Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the product of the MWhs of Virtual Supply Awards and the simple average of the four FMM LMPs for the applicable Trading Hour at the Eligible PNode or Eligible Aggregated PNode.

### The CAISO pays or charges, depending on whether the value is positive or negative, the product of the virtual Forecasted Movement quantity and the difference between the FMM Flexible Ramp Up Price and the FMM Flexible Ramp Down Price11.3.2 Virtual Demand Awards

The CAISO will charge each Scheduling Coordinator with Virtual Demand Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the Day-Ahead Market LMP at the Eligible PNode or Eligible Aggregated PNode multiplied by the MWhs of Virtual Demand Awards. Virtual Demand Awards subject to price correction will be settled as specified in Section 11.21.

The CAISO will pay each Scheduling Coordinator with Virtual Demand Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the product of the MWhs of Virtual Demand Awards and the simple average of the four FMM LMPs for the applicable Trading Hour at the Eligible PNode or Eligible Aggregated PNode.

The CAISO pays or charges, depending on whether the value is positive or negative, the product of the virtual Forecasted Movement quantityand the difference between the FMM Flexible Ramp Up Price and the FMM Flexible Ramp Down Price.

\* \* \*

## 11.5 Real-Time Market Settlements

The CAISO shall calculate and account for imbalance energy for each Dispatch Interval and settle imbalance energy in the Real-Time Market for each Settlement Interval for each resource within the CAISO Balancing Authority Area and all System Resources dispatched in Real-Time. There are four (4) categories of imbalance energy: FMM Instructed Imbalance Energy, RTD Instructed Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted For Imbalance Energy. FMM Instructed Imbalance Energy includes all Energy associated with the FMM Schedule. FMM Instructed Imbalance Energy is settled pursuant to Section 11.5.1.1, including any Energy related with HASP Intertie Block Schedules cleared through the FMM. RTD Instructed Imbalance Energy is settled pursuant to Section 11.5.1.2, Uninstructed Imbalance Energy is settled pursuant to Section 11.5.2, and Unaccounted For Energy is settled pursuant to Section 11.5.3. To the extent that the sum of the Settlements Amounts for FMM Instructed Imbalance Energy, RTD Instructed Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted For Energy does not equal zero, the CAISO will assess charges or make payments for the resulting differences to all Scheduling Coordinators based on a pro rata share of their Measured Demand for the relevant Settlement Interval, as further described in Section 11.5.4. FMM Instructed Imbalance Energy and RTD Instructed Imbalance Energy due to Exceptional Dispatches, as well as the allocation of related costs, including Excess Costs Payments, are settled as described in Section 11.5.6. The CAISO shall reverse RTM Congestion Charges for valid and balanced ETC and TOR Self-Schedules as described in Section 11.5.7. The CAISO will settle Energy for emergency assistance as described in Section 11.5.8.

### 11.5.1 Imbalance Energy Settlements

**11.5.1.1 FMM Instructed Imbalance Energy Settlements**

For each Settlement Interval, FMM Instructed Imbalance Energy consists of the following types of Energy: (1) FMM Optimal Energy; (2) FMM Minimum Load Energy; (3) FMM Exceptional Dispatch Energy; (4) FMM Derate Energy; and (5) FMM Pumping Energy. Payments and charges for FMM Instructed Imbalance Energy attributable to each resource in each Settlement Interval shall be settled by debiting or crediting, as appropriate, the specific Scheduling Coordinator’s FMM IIE Settlement Amount. The FMM IIE Settlement Amounts for FMM Optimal Energy, FMM Minimum Load Energy, FMM Derate Energy, and FMM Pumping Energy shall be calculated as the product of the sum of all of these types of Energy and the FMM LMP. For MSS Operators that have elected net Settlement, the FMM IIE Settlement Amounts for Energy dispatched through the FMM optimization shall be calculated as the product of the FMM MSS Price and the sum of the following types of Energy: FMM Minimum Load Energy from System Units dispatched in FMM, FMM Derate Energy, and FMM Pumping Energy. For MSS Operators that have elected gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the FMM Instructed Imbalance Energy for such entities is settled similarly to non-MSS entities as provided in this Section 11.5.1.1. The remaining FMM IIE Settlement Amounts for Exceptional Dispatches are settled pursuant to Section 11.5.6.

**11.5.1.2 RTD Instructed Imbalance Energy Settlements**

For each Settlement Interval, RTD Instructed Imbalance Energy consists of the following types of Energy: (1) RTD Optimal Energy; (2) Residual Imbalance Energy; (3) RTD Minimum Load Energy; (4) RTD Exceptional Dispatch Energy; (5) Regulation Energy; (6) Standard Ramping Energy; (7) Ramping Energy Deviation; (8) RTD Derate Energy; (9) MSS Load Following Energy; (10) RTD Pumping Energy; and (11) Operational Adjustments. Payments and charges for RTD Instructed Imbalance Energy attributable to each resource in each Settlement Interval shall be settled by debiting or crediting, as appropriate, the specific Scheduling Coordinator’s RTD IIE Settlement Amount. The RTD IIE Settlement Amounts for the Standard Ramping Energy shall be zero. The RTD IIE Settlement Amounts for RTD Optimal Energy, RTD Minimum Load Energy, Regulation Energy, Ramping Energy Deviation, RTD Derate Energy, and RTD Pumping Energy shall be calculated as the product of the sum of all of these types of Energy and the RTD LMP. For MSS Operators that have elected net Settlement, the RTD IIE Settlement Amounts for Energy dispatched through the RTD optimization shall be calculated as the product of the RTD MSS Price and the sum of the following types of Energy: RTD Minimum Load Energy from System Units dispatched in Real-Time, Regulation Energy, Ramping Energy Deviation, RTD Derate Energy, MSS Load Following Energy, and RTD Pumping Energy. For MSS Operators that have elected gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the RTD Instructed Imbalance Energy for such entities is settled similarly to non-MSS entities as provided in this Section 11.5.1.2. The remaining RTD IIE Settlement Amounts are determined as follows: (1) RTD IIE Settlement Amounts for Residual Imbalance Energy are determined pursuant to Section 11.5.5; and (2) RTD IIE Settlement Amounts for Exceptional Dispatches are settled pursuant to Section 11.5.6.

### 11.5.2 Uninstructed Imbalance Energy

Scheduling Coordinators shall be paid or charged a UIE Settlement Amount for each LAP, PNode or Scheduling Point for which the CAISO calculates an Uninstructed Imbalance Energy quantity for each Settlement Interval. Uninstructed Imbalance Energy quantities are calculated for each resource that has a Day-Ahead Schedule, Dispatch Instruction, Real-Time Interchange Export Schedule or Metered Quantity. For MSS Operators electing gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the Uninstructed Imbalance Energy for such entities is settled similarly to how Uninstructed Imbalance Energy for non-MSS entities is settled as provided in this Section 11.5.2. The CAISO shall account for Uninstructed Imbalance Energy every five minutes based on the resource’s Dispatch Instruction. For all resources, including Generating Units, System Units of MSS Operators that have elected gross Settlement, Physical Scheduling Plants, System Resources, Distributed Energy Resource Aggregations and all Participating Load, Reliability Demand Response Resources, and Proxy Demand Resources, the UIE Settlement Amount is calculated for each Settlement Interval as the product of its Uninstructed Imbalance Energy MWh quantity and the applicable RTD LMP. The UIE Settlement Amount for non-Participating Load and MSS Demand under gross Settlement is settled as described in Section 11.5.2.2. For MSS Operators that have elected net Settlement, the UIE Settlement Amount is calculated for each Settlement Interval as the product of its Uninstructed Imbalance Energy quantity and RTD MSS Price.

**11.5.2.1 Resource Specific Tier 1 UIE Settlement Interval Price**

The Resource-Specific Tier 1 UIE Settlement Interval Price is calculated as the resource’s total FMM IIE Settlement Amount and RTD IIE Settlement Amount, calculated pursuant to Sections 11.5.1.1 and 11.5.1.2 for that Settlement Interval divided by its total FMM Instructed Imbalance Energy quantity (MWh) calculated pursuant to Sections 11.5.1.1 and 11.5.1.2.

**11.5.2.2 Hourly Real-Time Demand Settlement**

The Default LAP Hourly Real-Time Price will apply to CAISO Demand and MSS Demand under net Settlement of imbalance energy, except for CAISO Demand not settled at the Default LAP as provided in Section 30.5.3.2, and per the methodology as may be further defined in the Business Practice Manuals. For each Settlement Interval, the differences between the Day-Ahead Scheduled CAISO Demand and Metered Demand (MWh) is settled at the Default LAP Hourly Real-Time Price or the Custom LAP Hourly Real-Time Price, as appropriate. For each Default LAP, the CAISO calculates the applicable Default LAP Hourly Real-Time Price as the weighted average LMP of the four Default LAP FMM LMPs and the twelve (12) five-minute Default LAP RTD LMPs. The CAISO calculates the weighted average LMP for each Default LAP as the summation of the weighted average SMEC, the weighted average MCC, and the weighted average MCL for that Default LAP. The CAISO calculates the weighted average SMEC, MCC, and MCL for each applicable Trading Hour based on the four applicable Default LAP FMM SMECs, MCCs, and MCLs, respectively, and the twelve (12) applicable Default LAP RTD SMECs, MCCs, and MCLs, respectively. For each Custom LAP, the CAISO calculates the applicable Custom LAP Hourly Real-Time Price as the weighted average LMP of the four Custom LAP FMM LMPs and the twelve (12) five-minute Custom LAP RTD LMPs. The CAISO calculates the weighted average LMP for each Custom LAP as the summation of the weighted average SMEC, the weighted average MCC, and the weighted average MCL for that Custom LAP. The CAISO calculates the weighted average SMEC, MCC, and MCL for each applicable Trading Hour based on the four applicable Custom LAP FMM SMECs, MCCs, and MCLs, respectively, and the twelve (12) applicable Custom LAP RTD SMECs, MCCs, and MCLs, respectively. In calculating the weighted average SMEC, MCC, and MCL for each hour for either the Default LAPs or Custom LAPs, the CAISO determines the weights based on the difference between Day-Ahead Schedules at the applicable LAP and the CAISO Forecast of BAA Demand for the CAISO used in the FMM multiplied by the relevant FMM LMP at the applicable LAP plus the difference between the CAISO Forecast of BAA Demand for the CAISO used in the FMM and the CAISO Forecast of BAA Demand for the CAISO used in the RTD multiplied by the relevant RTD LMP at the applicable LAP divided by the sum of the difference between Day-Ahead Schedules at the applicable LAP and the CAISO Forecast of BAA Demand for the CAISO used in the FMM plus the difference between the CAISO Forecast of BAA Demand for the CAISO used in the FMM and the CAISO Forecast of BAA Demand for the CAISO used in the RTD. Furthermore, the Default LAP Hourly Real-Time Prices and the Custom LAP Hourly Real-Time Prices will be bounded by the maximum and the lowest LMP and its components, for the applicable Trading Hour from those relevant intervals at the relevant LAP. If the calculated price exceeds the upper boundary or is below the lower boundary, then the Default LAP Hourly Real-Time Price or the Custom LAP Hourly Real-Time Price, as appropriate, instead will be calculated based on a weighted average price with the weightings based on gross deviations (absolute value of each deviation).

The Hourly Real-Time LAP Prices are determined by the requirements in Section 27.2.2.2.

**11.5.2.3 Revenue Neutrality Resulting from Changes in LAP Load Distribution Factors**

Any resulting revenue from changes in the LAP Load Distribution Factors between the Day-Ahead Market and the Real-Time Dispatch shall be allocated to metered CAISO Demand in the corresponding Default LAP.

**11.5.2.4 [Not used]**

### 11.5.3 Unaccounted For Energy

For each Settlement Interval, the CAISO will calculate Unaccounted For Energy for each utility Service Area for which the IOU or Local Publicly Owned Electric Utility has requested separate Unaccounted For Energy calculation and has met the requirements applicable to a CAISO Metered Entity. The Unaccounted For Energy will be settled at the applicable LAP Hourly Real-Time Price calculated for each utility Service Area for which Unaccounted For Energy is calculated separately. Unaccounted For Energy will be allocated to each Scheduling Coordinator based on the ratio of its metered CAISO Demand within the relevant utility Service Area for which Unaccounted For Energy is calculated separately to total metered CAISO Demand within that utility Service Area.

### 11.5.4 Imbalance Energy Pricing; Non-Zero Offset Amount Allocation

**11.5.4.1 Real-Time Imbalance Energy Offset**

(a) **Financial Value of EIM Transfers.** For each Balancing Authority Area in the EIM Area, the CAISO will calculate the Real-Time Market financial value of EIM Transfers as the product of the EIM Transfer MWh, either positive or negative, and the System Marginal Energy Cost, plus a greenhouse gas financial value credit calculated as the product of the portion of the EIM Transfers that do not correspond to a greenhouse gas compliance obligation under the regulations administered by the California Air Resources Board and the Marginal Greenhouse Gas Cost.

(b) **Initial Calculation.** The CAISO will initially calculate the Real-Time Imbalance Energy Offset to be recovered on a 5-minute basis for each Balancing Authority Area in the EIM Area as the sum of the financial value of EIM Transfers and the Settlement amounts for FMM Instructed Imbalance Energy and RTD Instructed Imbalance Energy, Uninstructed Imbalance Energy, Greenhouse Gas Emissions Cost Revenue, and Unaccounted For Energy, and for the CAISO, Real-Time Virtual Bid Settlement, plus the Real-Time Ancillary Services Congestion revenues and Virtual Awards settlements in the Real-Time Market in accordance with Section 11.3, less the Real-Time Congestion Offset and less the Real-Time Marginal Cost of Losses Offset.

(c) **Allocation.** The CAISO will allocate the adjusted Real-Time Imbalance Energy Offset:

(1) for the CAISO Balancing Authority Area, to Scheduling Coordinators in the CAISO Balancing Authority Area according to Measured Demand; and

(2) for EIM Entity Balancing Authority Areas, to the applicable EIM Entity Scheduling Coordinator.

(d) **Residual Neutrality Amounts.** The CAISO will allocate any residual Real-Time Imbalance Energy Offset amount to Scheduling Coordinators in the EIM Area based upon EIM Measured Demand.

**11.5.4.1.1 Real-Time Congestion Offset.**

(a) **Contribution to Marginal Cost of Congestion.** For each Settlement Period of the RTM, the CAISO shall calculate the contribution of each Balancing Authority Area in the EIM Area to the Marginal Cost of Congestion at each resource location and intertie in the EIM Area for each Balancing Authority Area based on the location of the Transmission Constraints in each Balancing Authority Area, EIM External Interties, and constraints enforced outside of the EIM Area needed to manage that Balancing Authority Area’s responsibilities.

(b) **Real-Time Congestion Offset.**  For each Settlement Period of the RTM, the CAISO shall calculate the Real-Time Congestion Offset for each Balancing Authority Area in the EIM Area as –

(1) the sum of the product of the contribution of that Balancing Authority Area as determined in subsection (a) of this section, the Marginal Cost of Congestion component of the Locational Marginal Price at each resource location in the EIM Area, and the imbalance energy at that resource location, including Virtual Bids at that resource location;

(2) minus any Virtual Bid adjustment as determined in accordance with section 11.5.4.1.1(d).

(c) **Treatment of EIM Internal Interties.**

(1) **Characterization of Transmission Rights.** As the terms are used for the purposes assigning congestion revenue to a Balancing Authority Area pursuant to section (c)(3), the CAISO or an EIM Entity provides –

(A) transmission “to” an EIM Internal Intertie if a transaction using that transmission must compete at that location with transactions using transmission that is not provided by the CAISO or an EIM Entity;

(B) transmission “through” an EIM Internal Intertie if a transaction using that transmission does not compete at that location with transactions using transmission that is not provided by the CAISO or an EIM Entity.

(2) **EIM Intertie that Operates Only as an EIM Internal Intertie.** In performing the calculation in subsection (a) of this section in the case of an EIM Intertie that operates only as an EIM Internal Intertie, the CAISO shall determine a Balancing Authority Area’s contribution to the Congestion at the intertie by –

(A) dividing the congestion revenue equally to each side of the intertie as determined by the Balancing Authority Area boundary at that intertie; then

(B) allocating the congestion revenue divided in subsection (c)(12)(A) of this section to each side of the intertie among the Balancing Authority Areas that share that side of the intertie in proportion to the Balancing Authority Area’s contribution to the EIM Transfer limit.

(3) **EIM Intertie that Operates Both as an EIM Internal Intertie and an EIM External Intertie or a Scheduling Point.**  In performing the calculation in subsection (a) of this section in the case of an EIM Intertie that operates both as an EIM Internal Intertie and an EIM External Intertie or Scheduling Point, the CAISO shall determine a Balancing Authority Area’s contribution to the Congestion at the intertie by –

(A) assigning congestion revenue attributable to a constraint at the EIM Internal Intertie associated with the CAISO’s or an EIM Entity’s provision of transmission to the EIM Internal Intertie to the Balancing Authority Areas in the EIM Area that provide transmission to the EIM Internal Intertie in proportion to each EIM Entity’s contribution to the EIM Transfer limit;

(B) assigning congestion revenue attributable to a constraint at the EIM Internal Intertie associated with the CAISO’s or an EIM Entity’s provision of transmission through the EIM Internal Intertie to the Balancing Authority Areas in the EIM Area that provide transmission through the EIM Internal Intertie in accordance with the calculation in subsection (c)(2) of this section; and

(C) assigning congestion revenue attributable to the EIM External Intertie or the Scheduling Point to the Balancing Authority Area in the EIM Area that manages the transmission rights on that intertie.

(4) **EIM Intertie that Operates Only as an EIM External Intertie.**  In performing the calculation in subsection (a) of this section in the case of an EIM Intertie that operates only as an EIM External Intertie, the CAISO shall determine a Balancing Authority Area’s contribution to the Congestion at the intertie by allocating the congestion revenue to the Balancing Authority Area in the EIM Area that manages the intertie.

(d) **Virtual Bid Adjustment.**

(1) **Individual Constraint Calculation.**  For each Transmission Constraint in an EIM Entity Balancing Authority Area, the CAISO will calculate a Virtual Bid adjustment as the product of that Transmission Constraint’s FMM Shadow Price and the lesser of –

(A) the Flow Impact of Virtual Bids and

(B) the Flow Impacts of all Day-Ahead Scheduled Energy and EIM Base Schedules less the Flow Impacts of FMM Schedules,

but not less than zero.

(2) **EIM Entity Balancing Authority Area Calculation.** Each EIM Entity Balancing Authority Area’s Virtual Bid adjustment shall be the sum of the individual Transmission Constraint calculation for all Transmission Constraints within that EIM Entity Balancing Authority Area.

(e) **Allocation.**  The CAISO will allocate –

(1) the Real-Time Congestion Offset for each EIM Entity Balancing Authority Area to the applicable EIM Entity Scheduling Coordinator;

(2) the Real-time Congestion Offset for the CAISO Balancing Authority Area in accordance with Section 11.5.4.2; and

(3) the Virtual Bid adjustment from each individual constraint calculation to each Scheduling Coordinator who submitted Virtual Bids based on that Scheduling Coordinator’s Virtual Award’s pro rata share of the gross positive Congestion revenues received by all Virtual Awards from that Transmission Constraint.

**11.5.4.1.2 Real-Time Marginal Cost of Losses Offset**

(a) **Calculation.** The CAISO will calculate the Real-Time Marginal Cost of Losses Offset for each Balancing Authority Area as the sum of the product of the Marginal Loss component of the LMP and all positive or negative FMM Instructed Imbalance Energy, RTD Instructed Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted For Energy in the Balancing Authority Area.

(b) **Allocation.**  The CAISO will allocate the amounts determined according to section 11.5.4.1.2(a) –

(1) for the CAISO Balancing Authority Area, according to section 11.5.4.2; and

(2) for EIM Entity Balancing Authority Areas, to the applicable EIM Entity Scheduling Coordinator.

**11.5.4.2 Allocations of Non-Zero Amounts of the Sum of the FMM Instructed Imbalance Energy, RTD Instructed Imbalance Energy, RTD Imbalance Energy, Uninstructed Imbalance Energy, Unaccounted For Energy, the Real-Time Ancillary Services Congestion Revenues and Real-Time Virtual Awards Settlements**

The CAISO will first compute (1) the Real-Time Congestion Offset and allocate it to all Scheduling Coordinators, based on Measured Demand, excluding Demand associated with ETC or TOR Self-Schedules for which a RTM Congestion Credit was provided as specified in Section 11.5.7, and excluding Demand associated with ETC, Converted Right, or TOR Self-Schedules for which an IFM Congestion Credit was provided as specified in Section 11.2.1.5; and (2) the Real-Time Marginal Cost of Losses Offset and allocate it to all Scheduling Coordinators based on Measured Demand, excluding Demand associated with TOR Self-Schedules for which a RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.5.7.2, and excluding Demand associated with TOR Self-Schedules for which an IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.2.1.7. For Scheduling Coordinators for MSS operators that have elected to Load follow or net settlement, or both, the Real-Time Marginal Cost of Losses Offset will be allocated based on their MSS Aggregation Net Measured Demand excluding Demand associated with TOR Self-Schedules for which a RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.5.7.2, and excluding Demand associated with TOR Self-Schedules for which an IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.2.1.7. For Scheduling Coordinators for MSS Operators regardless of whether the MSS Operator has elected gross or net Settlement, the CAISO will allocate the Real-Time Congestion Offset based on the MSS Aggregation Net Non-ETC/TOR Measured Demand. To the extent that the sum of the Settlement amounts for FMM Instructed Imbalance Energy, RTD Instructed Imbalance Energy, RTD Imbalance Energy, Uninstructed Imbalance Energy, Unaccounted For Energy, the Real-Time Ancillary Services Congestion revenues and Virtual Awards settlements in the Real-Time Market in accordance with Section 11.3, less Real-Time Congestion Offset, and less the Real-Time Marginal Cost of Losses Offset, does not equal zero, the CAISO will assess charges or make payments for the resulting differences to all Scheduling Coordinators, including Scheduling Coordinators for MSS Operators that are not Load following MSSs and have elected gross Settlement, based on a pro rata share of their Measured Demand for the relevant Settlement Interval. For Scheduling Coordinators for MSS Operators that have elected net Settlement, the CAISO will assess charges or make payments for the resulting non-zero differences of the sum of the Settlement amounts for FMM Instructed Imbalance Energy, RTD Instructed Imbalance Energy, RTD Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted For Energy, the Real-Time Ancillary Services Congestion Revenues and Virtual Awards settlements in the Real-Time Market in accordance with Section 11.3, less Real-Time Congestion Offset and less the Real-Time Marginal Cost of Losses Offset, based on their MSS Aggregation Net Measured Demand. For Scheduling Coordinators for MSS Operators that have elected Load following, the CAISO will not assess any charges or make payments for the resulting non-zero differences of the sum of the Settlement amounts for FMM Instructed Imbalance Energy, RTD Instructed Imbalance Energy, RTD Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted For Energy, the Real-Time Ancillary Services Congestion Revenues and Virtual Awards settlements in the Real-Time Market in accordance with Section 11.3, less Real-Time Congestion Offset and less the Real-Time Marginal Cost of Losses Offset.

### 11.5.5 Settlement Amount for Residual Imbalance Energy

**11.5.5.1 In General**

For each Settlement Interval, Residual Imbalance Energy settlement amounts shall be the product of the MWh of Residual Imbalance Energy for that Settlement Interval and the Bid, as mitigated pursuant to Section 39.7 that led to the Residual Imbalance Energy from the relevant Dispatch Interval in which the resource was dispatched, subject to additional rules specified in this section below and in Section 11.17. The relevant Dispatch Interval and Bid that led to the Residual Imbalance Energy may occur prior or subsequent to the interval in which the relevant Residual Imbalance Energy occurs and can be contiguous, or not, with the applicable Trading Hour in which the relevant Residual Imbalance Energy Settlement Interval occurs.

**11.5.5.2 Eligible Intermittent Resources**

For Eligible Intermittent Resources, the Settlement Amount for any portion of the resource’s Residual Imbalance Energy that is greater than its forecasted output for a particular Settlement Interval will be the product of the MWh of Residual Imbalance Energy above the resource’s forecasted output for that Settlement Interval and the applicable RTD Locational Marginal Price or RTD MSS Price if the resource is MSS Net settled.

**11.5.5.3 Metered Sub-Systems**

For MSS Operators the Settlement for Residual Imbalance Energy is conducted in the same manner, regardless of any MSS elections (net/gross Settlement, Load following or opt-in/opt-out of RUC), except in the case of Eligible Intermittent Resources which are settled as specified in Section 11.5.5.2.

**11.5.5.4 Rerated Minimum Load**

When a Scheduling Coordinator increases the Minimum Load pursuant to Section 9.3.3, for the Settlement Interval(s) during which the affected resource is ramping up towards or ramping down from such a Minimum Load change, the Residual Imbalance Energy for the applicable Settlement Interval(s) will be re-classified as Derate Energy and will be paid at the applicable RTD Locational Marginal Price.

### 11.5.6 Settlement Amounts for RTD Instructed Imbalance Energy from Exceptional Dispatch

For each Settlement Interval, the RTD IIE Settlement Amount from each type of Exceptional Dispatch described in Section 34.11 is calculated as the sum of the products of the relevant FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy quantity for the Settlement Interval and the relevant FMM or RTD LMP Settlement price for each type of Exceptional Dispatch as further described in this Section 11.5.6. For MSS Operators the Settlement for FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy from Exceptional Dispatches is conducted in the same manner, regardless of any MSS elections (net/gross Settlement, Load following or opt-in/opt-out of RUC). Except for the Settlement price, Exceptional Dispatches to perform Ancillary Services testing, to perform PMax testing, and to perform pre-commercial operation testing for Generating Units are otherwise settled in the same manner as provided in Section 11.5.6.1. Notwithstanding any other provisions of this Section 11.5.6, the Exceptional Dispatch Settlement price that is applicable in circumstances in which the CAISO applies Mitigation Measures to Exceptional Dispatch of resources pursuant to Section 39.11 shall be calculated as set forth in Section 11.5.6.7.

**11.5.6.1 Settlement for FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy from Exceptional Dispatches used for System Emergency Conditions, for a Market Disruption, to Mitigate Overgeneration or to Prevent or Relieve Imminent System Emergencies**

The Exceptional Dispatch Settlement price for incremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy that is delivered as a result of an Exceptional Dispatch for System Emergency conditions, for a Market Disruption, to mitigate Overgeneration conditions, or to prevent or relieve an imminent System Emergency, including forced Start-Ups and Shut-Downs, is the higher of the (a) applicable FMM or RTD LMP; (b) the Energy Bid price; (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price; or (d) the negotiated price as applicable to System Resources. The Exceptional Dispatch price for incremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy that is delivered from an RMR Resource as a result of an Exceptional Dispatch for System Emergency conditions; for a Market Disruption; to mitigate Overgeneration conditions; or to prevent or relieve an imminent System Emergency, including forced Start-Ups and Shut-Downs, is the higher of (a) applicable FMM or RTD LMP; (b) the Energy Bid price adjusted to remove Opportunity Costs; or (c) the Default Energy Bid price adjusted to remove Opportunity Costs. Costs for incremental Energy for this type of Exceptional Dispatch are settled in two payments: (1) incremental Energy is first settled at the applicable FMM or RTD LMP and included in the total FMM IIE Settlement Amount or RTD IIE Settlement Amount described in Sections 11.5.1.1 and 11.5.1.2; and (2) the incremental Energy Bid Cost in excess of the applicable FMM or RTD LMP at the relevant Location is settled pursuant to Section 11.5.6.1.1. The Exceptional Dispatch Settlement price for decremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy that is delivered as a result of an Exceptional Dispatch Instruction for a Market Disruption, or to prevent or relieve a System Emergency, is the minimum of (a) the FMM or RTD LMP; (b) the Energy Bid price subject to Section 39.6.1.4; (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price; or (d) the negotiated price as applicable to System Resources. The Exceptional Dispatch price for decremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy that is delivered from an RMR Resource as a result of an Exceptional Dispatch for Emergency System conditions; for a Market Disruption; to mitigate Overgeneration conditions; or to prevent or relieve an imminent System Emergency, is the minimum of the (a) applicable FMM or RTD LMP; (b) the Energy Bid price adjusted to remove Opportunity Costs; or (c) the Default Energy Bid price adjusted to remove Opportunity Costs. All Energy costs for decremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy associated with this type of Exceptional Dispatch are included in the total FMM IIE Settlement Amount or RTD IIE Settlement Amount described in Sections 11.5.1.1 and 11.5.1.2.

**11.5.6.1.1 Settlement of Excess Cost Payments for Exceptional Dispatches used for System Emergency Conditions, for a Market Disruption, and to Avoid an Imminent System Emergency**

The Excess Cost Payment for incremental Exceptional Dispatches used for emergency conditions, for a Market Disruption, or to avoid an imminent System Emergency is calculated for each resource for each Settlement Interval as the cost difference between the Settlement amount calculated pursuant to Section 11.5.6.1 for the applicable Exceptional Dispatch at the FMM or RTD LMP and delivered Exceptional Dispatch quantity at one of the following three costs: (1) the resource’s Energy Bid Cost; (2) the Default Energy Bid cost; or (3) the Energy cost at the negotiated price, as applicable for System Resources, for the relevant Exceptional Dispatch. The Excess Cost Payment for incremental Exceptional Dispatches used for System Emergency conditions; for a Market Disruption; or to avoid an imminent System Emergency for an RMR Resource is the cost difference between the Settlement amount calculated pursuant to Section 11.5.6.1 and one of the following two costs: (1) the RMR Resource’s Energy Bid price adjusted to remove Opportunity Costs; or (2) the Default Energy Bid price adjusted to remove Opportunity Costs.

**11.5.6.2 Settlement of Instructed Imbalance Energy from Exceptional Dispatches Caused by Modeling Limitations**

The Exceptional Dispatch Settlement price for FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy that is consumed or delivered as a result of an Exceptional Dispatch to mitigate or resolve Congestion as a result of a transmission-related modeling limitation in the FNM as described in Section 34.11.3 is the maximum of (a) the FMM or RTD LMP; (b) the Energy Bid price; (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price; or (d) the negotiated price as applicable to System Resources. The Exceptional Dispatch Price for FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy that is consumed or delivered by an RMR Resource as a result of Exceptional Dispatch to mitigate or resolve Congestion as a result of a transmission-related modeling limitation in the FNM as described in Section 34.11.3 is the maximum of: (a) the applicable FMM or RTD LMP; (b) the Energy Bid price adjusted to remove Opportunity Costs; or (c) the Default Energy Bid price adjusted to remove Opportunity Costs. Costs for incremental Energy for this type of Exceptional Dispatch are settled in two payments: (1) incremental Energy is first settled at the FMM or RTD LMP and included in the total FMM IIE Settlement Amount or RTD IIE Settlement Amount described in Sections 11.5.1.1 and 11.5.1.2; and (2) the incremental Energy Bid costs in excess of the applicable LMP at the relevant Location are settled per Section 11.5.6.2.3. The Exceptional Dispatch Settlement price for decremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy for this type of Exceptional Dispatch is the minimum of (a) the FMM or RTD LMP; (b) the Energy Bid price; (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price; or (d) the negotiated price as applicable to System Resources. The Exceptional Dispatch Settlement price for decremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy for this type of Exceptional Dispatch from an RMR Resource is the minimum of: (a) the FMM or RTD LMP; (b) the Energy Bid price adjusted to remove Opportunity Costs; or (c) the Default Energy Bid price adjusted to remove Opportunity Costs. Costs for decremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy associated with this type of Exceptional Dispatch are settled in two payments: (1) decremental Energy is first settled at the FMM or RTD LMP and included in the total FMM IIE Settlement Amount or RTD IIE Settlement Amount described in Sections 11.5.1.1 and 11.5.1.2; and (2) the decremental Energy Bid costs in excess of the applicable LMP at the relevant Location are settled per Section 11.5.6.2.3.

**11.5.6.2.1 [Not Used]**

**11.5.6.2.2 [Not Used]**

**11.5.6.2.3 Settlement of Excess Cost Payments for Exceptional Dispatches used for Transmission-Related Modeling Limitations**

The Excess Cost Payment for Exceptional Dispatches used for transmission-related modeling limitations as described in Section 34.11.3 is calculated for each resource for each Settlement Interval as the cost difference between the Settlement amount calculated pursuant to Section 11.5.6.2 for the applicable delivered Exceptional Dispatch quantity at the FMM or RTD LMP and one of the following three costs: (1) the resource's Energy Bid Cost; (2) the Default Energy Bid cost; or (3) the Energy cost at the negotiated price, as applicable for System Resources, for the relevant Exceptional Dispatch. The Excess Cost Payment for Exceptional Dispatches for transmission-related modeling limitations as described in Section 34.11.3 is calculated for each RMR Resource for each Settlement Interval as the cost difference between the Settlement amount calculated pursuant to Section 11.5.6.2 for the applicable delivered Exceptional Dispatch quantity at the FMM or RTD LMP and one of the following two costs: (1) the resource’s Energy Bid Cost adjusted to remove Opportunity Costs; or (2) the Default Energy Bid cost adjusted to remove Opportunity Costs, for the relevant Exceptional Dispatch.

**11.5.6.2.4 Exceptional Dispatches for Non-Transmission-Related Modeling Limitations**

The Exceptional Dispatch Settlement price for incremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy that is consumed or delivered as a result of an Exceptional Dispatch to mitigate or resolve Congestion that is not a result of a transmission-related modeling limitation in the FNM as described in Section 34.11.3 is the maximum of the (a) FMM or RTD LMP; (b) Energy Bid price; (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price; or (d) the negotiated price as applicable to System Resources. For RMR Resources, the Exceptional Dispatch Settlement price for incremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy as a result of an Exceptional Dispatch to mitigate or resolve Congestion that is not a result of a transmission-related modeling limitation in the FNM as described in Section 34.11.3 is the maximum of: (a) FMM or RTD LMP; (b) Energy Bid price adjusted to remove Opportunity Costs; or (c) the Default Energy Bid price adjusted to remove Opportunity Costs. For resources that receive an Exceptional Dispatch energy instruction prior to the Operating Day, the Exceptional Dispatch Settlement price is the maximum of the (a) applicable FMM or RTD LMP; (b) IFM Energy Bid price; or (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Day-Ahead Market and for the Energy that does not have a IFM Energy Bid price. All costs for incremental Energy for this type of Exceptional Dispatch will be included in the total FMM IIE Settlement Amount or RTD IIE Settlement Amount described in Sections 11.5.1.1 and 11.5.1.2. The Exceptional Dispatch Settlement price for decremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy for this type of Exceptional Dispatch is the minimum of the (a) FMM or RTD LMP; (b) Energy Bid Price; (c) Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price; or (d) negotiated price as applicable to System Resources. For RMR Resources; the Exceptional Dispatch Settlement for decremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy for this type of Exceptional Dispatch is the minimum of the: (a) FMM or RTD LMP; (b) Energy Bid price adjusted to remove Opportunity Costs; or (c) Default Energy Bid price adjusted to remove Opportunity Costs. All costs for decremental FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy associated with this type of Exceptional Dispatch are included in the total FMM IIE Settlement Amount or RTD IIE Settlement Amount described in Sections 11.5.1.1 and 11.5.1.2.

**11.5.6.2.5 Allocation of Exceptional Dispatch Excess Cost Payments**

**11.5.6.2.5.1 Allocation of Exceptional Dispatch Excess Cost Payments to PTOs**

The total Excess Cost Payments calculated pursuant to Section 11.5.6.2.3 for the FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy from Exceptional Dispatches instructed as a result of a transmission-related modeling limitation in the FNM as described in Section 34.11.3 in that Settlement Interval shall be charged to the Participating Transmission Owner in whose PTO Service Territory the transmission-related modeling limitation as described in Section 34.11.3 is located. If the modeling limitation affects more than one Participating TO, the Excess Cost Payments shall be allocated in proportion to the Transmission Revenue Requirements of the affected Participating TOs with PTO Service Territories. Costs allocated to Participating TOs under this section shall constitute Reliability Services Costs.

**11.5.6.2.5.2 Allocation of Exceptional Dispatch Costs to Scheduling Coordinators**

Excess Cost Payments for the Exceptional Dispatches used for emergency conditions and to avoid Market Disruption and System Emergencies as determined pursuant to Section 11.5.6.1.1 shall be charged to Scheduling Coordinators as follows in a two-step process. First, each Scheduling Coordinator’s charge shall be the lesser of:

(i) the pro rata share of total Excess Cost Payment based upon the ratio of each Scheduling Coordinator's Net Negative Uninstructed Deviations to the total system Net Negative Uninstructed Deviations; or

(ii) the amount obtained by multiplying the Scheduling Coordinator’s Net Negative Uninstructed Deviation for each Settlement Interval and a weighted average price. The weighted average price is equal to the total Excess Cost Payments to be allocated divided by the MWh of FMM Exceptional Dispatch Energy or RTD Exceptional Dispatch Energy associated with the Excess Cost Payment.

Second, any remaining unallocated costs shall be allocated to all Scheduling Coordinators pro-rata based on their Measured Demand. For a Scheduling Coordinator of an MSS Operator that has elected to follow Load, allocation of this second category of Excess Cost Payments will be based on net metered MSS Demand. In addition, to the extent the Exceptional Dispatches are made to resolve congestion internal to the MSS, the Scheduling Coordinator for such an MSS will also be subject to these two categories of Excess Cost Payments.

A Scheduling Coordinator shall be exempt from the first category of the Excess Cost Payment allocation for a Settlement Interval if the Scheduling Coordinator has sufficient incremental Energy Bids that are from physically available resources in the Real-Time Market for Energy to cover its Net Negative Uninstructed Deviation in the given Settlement Interval and that have been approved by the CAISO consistent with Sections 30.7.12 and 30.11.

**11.5.6.3 Settlement for Instructed Imbalance Energy from Exceptional Dispatches for Condition 2 Legacy RMR Units**

**11.5.6.3.1 Pricing for Exceptional Dispatch of Legacy RMR Units**

If the CAISO dispatch a Legacy RMR Unit that has selected Condition 2 of its Legacy RMR Contract to Start-Up or provide Energy other than a Start-Up or Energy pursuant to the Legacy RMR Contract, the CAISO shall pay as follows

(a) if the Owner has elected Option A of Schedule G, two times the Start-Up Cost specified in Schedule D to the applicable Legacy RMR Contract for any Start-Up incurred, and 1.5 times the rate specified in Equation 1a or 1b below times the amount of Energy delivered in response to the Dispatch Instructions;

(b) if the Owner has elected Option B of Schedule G, three times the Start-Up Cost specified in Schedule D to the applicable Legacy RMR Contract for any Start-Up incurred, and the rate specified in Equation 1a or 1b below times the amount of Energy delivered in response to the Dispatch Instruction.

Equation 1a

Energy Price ($/MWh) = (AX3 + BX2 + CX + D) \* P \* E + Variable O&M Rate

X

Equation 1b

Energy Price ($/MWh) = A \* (B + CX + DeFX) \* P \* E + Variable O&M Rate

 X

Where:

* for Equation 1a, A, B, C, D and E are the coefficients given in Table C1-7a of the applicable Legacy RMR Contract;
* for Equation 1b, A, B, C, D, E and F are the coefficients given in Table C1-7b of the applicable Legacy RMR Contract;
* X is the Unit output level during the applicable settlement period, MWh;
* P is the Hourly Fuel Price as calculated by Equation C1-8 in Schedule C using the Commodity Prices in accordance with the applicable Legacy RMR Contract;

Variable O&M Rate ($/MWh): as shown on Table C1-18 of the applicable Legacy RMR Contract.

**11.5.6.3.2 Allocation of Costs from Exceptional Dispatch Calls to Condition 2 RMR Units**

(a) All costs associated with Energy provided by a Condition 2 RMR Unit operating other than according to a RMR Dispatch shall be allocated in accordance with Section 11.5.4.2.

(b) Start-Up Costs for Legacy Condition 2 RMR Units providing service outside the Legacy RMR Contract shall be treated similar to costs under Section 11.5.6.2.5.2.

**11.5.6.4 Settlement of Instructed Imbalance Energy from Exceptional Dispatches for Testing**

The Exceptional Dispatch Settlement price for incremental FMM Instructed Imbalance Energy and RTD Instructed Imbalance Energy that is consumed or delivered as a result of an Exceptional Dispatch for purposes of Ancillary Services testing, periodic testing, including PMax testing, or pre-commercial operation testing for Generating Units is the maximum of the FMM or RTD LMP or the Default Energy Bid price. All Energy costs for these types of Exceptional Dispatch will be included in the FMM IIE Settlement Amount and RTD IIE Settlement Amount described in Sections 11.5.1.1 and 11.5.1.2.

**11.5.6.5 Settlement of RTD Instructed Imbalance Energy from Black Start**

Unless otherwise specified in a Black Start Agreement, all FMM IIE Settlement Amounts or RTD IIE Settlement Amounts associated with Black Start receive the Exceptional Dispatch Settlement price as provided in Section 11.5.6.1, but the costs are allocated pursuant to Section 11.4.

**11.5.6.6 Settlement from Instructed Imbalance Energy from Exceptional Dispatches for Real-Time ETC and TOR Self-Schedules**

The Exceptional Dispatch Settlement price for FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy from Real-Time ETC and TOR Self-Schedules shall be the FMM or RTD LMP. The FMM IIE Settlement Amount and RTD IIE Settlement Amount for this type of Exceptional Dispatch shall be calculated as the product of the sum of all of these types of Energy and the FMM or RTD LMP. All Energy costs for these types of Exceptional Dispatches will be included in the FMM IIE Settlement Amount and RTD IIE Settlement Amount described in Sections 11.5.1.1 and 11.5.1.2.

**11.5.6.7 Settlement of FMM or RTD Exceptional Dispatch Energy**

**11.5.6.7.1 Settlement of FMM or RTD Exceptional Dispatch Energy from Exceptional Dispatches of Resources Eligible for Supplemental Revenues**

Except as specified in Section 11.5.6.7.3, the Exceptional Dispatch Settlement price for the FMM Exceptional Dispatch Energy or RTD Exceptional Dispatch Energy delivered by a resource that satisfies all of the criteria set forth in Section 39.10.1 shall be the higher of (a) the resource’s Energy Bid price or (b) the FMM or RTD LMP.

**11.5.6.7.2 Settlement of FMM or RTD Exceptional Dispatch Energy from Exceptional Dispatches of Resources Not Eligible for Supplemental Revenues**

Except as specified in Section 11.5.6.7.3, the Exceptional Dispatch Settlement price for the FMM Exceptional Dispatch Energy or RTD Exceptional Dispatch Energy delivered by a resource that satisfies all of the criteria set forth in Section 39.10.2 shall be the higher of (a) the Default Energy Bid price or (b) the Resource-Specific Settlement Interval LMP.

**11.5.6.7.3 Exception to the Other Provisions of Section 11.5.6.7**

If the Energy Bid price for a resource that satisfies all of the criteria set forth in Sections 39.10.1 or 39.10.2 is lower than the Default Energy Bid price for the resource, and the FMM or RTD LMP is lower than both the Energy Bid price for the resource and the Default Energy Bid price for the resource, the FMM Exceptional Dispatch Energy or RTD Exceptional Dispatch Settlement price for the Exceptional Dispatch Energy delivered by the resource shall be the Energy Bid price for the resource.

### 11.5.7 Congestion Credit and Marginal Credit of Losses Credit

**11.5.7.1 RTM Congestion Credit for ETCs and TORs**

The CAISO shall not apply charges or payments to Scheduling Coordinators related to the MCC associated with all Points of Receipt and Points of Delivery pairs associated with valid and balanced ETC Self-Schedules or TOR Self-Schedules after the Day-Ahead Market. The balanced portion for each ETC or TOR contract for each Settlement Interval will be based on the difference between: (1) the minimum of (a) the total Demand, (b) the total ETC or TOR Supply Self-Schedule submitted in RTM, including changes after twenty (20) minutes before the applicable Trading Hour if such change is permitted by the Existing Contract, or (c) the Existing Contract maximum capacity as specified in the TRTC Instructions; and (2) the valid and balanced portion of the Day-Ahead Schedule. In determining the balanced portions, the CAISO evaluates the amounts based on the following variables: (a) for exports and imports, the CAISO shall use the schedule quantity specified in the Interchange schedule used for check out between CAISO and other Balancing Authority Areas; (b) for CAISO Demand, the CAISO shall use the Gross Load associated with the applicable ETC or TOR; and (c) for all Generation the CAISO shall use the quantity specified in the Dispatch Instructions. For each Scheduling Coordinator, the CAISO shall determine for each Settlement Interval the applicable RTM Congestion Credit for FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy, which can be positive or negative, as the sum of the product of the relevant MWh quantity and the applicable weighted average MCC at each Point of Receipt and Point of Delivery associated with the valid and balanced portions of that Scheduling Coordinator’s ETC or TOR Self-Schedules. The weights in the two markets will be based on the absolute values of the (a) deviation of the FMM Schedule or the CAISO Forecast of BAA Demand for the CAISO used in the FMM from Day-Ahead Schedules and (b) deviation of the RTD schedule or the CAISO Forecast of BAA Demand for the CAISO used in the RTD from Day-Ahead Schedules.

**11.5.7.2 RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules**

For all Points of Receipt and Points of Delivery pairs associated with a valid and balanced TOR Self-Schedule submitted to the RTM pursuant to an existing agreement between the TOR holder and either the CAISO or a Participating TO as specified in Section 17.3.3, the CAISO shall not impose any charge or make any payment to the Scheduling Coordinator related to the MCL associated with such TOR Self-Schedules and will instead impose any applicable charges for losses as specified in the existing agreement between the TOR holder and either the CAISO or a Participating TO applicable to the relevant TOR. In any case in which the TOR holder has an existing agreement regarding its TORs with either the CAISO or a Participating TO, the provisions of the agreement shall prevail over any conflicting provisions of this Section 11.5.7.2. Where the provisions of this Section 11.5.7.2 do not conflict with the provisions of the agreement, the provisions of this Section 11.5.7.2 shall apply to the subject TORs. The balanced portion of the TOR Self-Schedule after the Day-Ahead Market is the same balanced quantity mentioned in this Section 11.5.7.2 for the TOR Self-Schedule. For each Scheduling Coordinator, the CAISO shall determine for each Settlement Interval the applicable RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules for FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy, which can be positive or negative, as the sum of the product of the relevant MWh quantity and the weighted average MCL at each of the eligible Points of Receipt and Points of Delivery associated with the valid and balanced portions of that Scheduling Coordinator’s TOR Self-Schedules. The weights in the two markets will be based on the absolute values of the: (a) deviation of the FMM Schedule or the CAISO Forecast of BAA Demand for the CAISO used in the FMM from Day-Ahead Schedules; and (b) deviation of the RTD schedule or the CAISO Forecast of BAA Demand for the CAISO used in the RTD from Day-Ahead Schedules. For losses that the CAISO shall charge pursuant to Section 17.3.3, the specific loss charge amount shall be the product of: (a) the specific loss percentage as may be specified in an applicable agreement between the TOR holder and the CAISO or an existing agreement between the TOR holder and a Participating TO; (b) the weighted average SMEC price from the FMM and RTD markets with weights based on the absolute values of (1) deviation of FMM schedule or CAISO Forecast of BAA Demand for the CAISO used in the FMM from Day-Ahead Schedules and (2) deviation of RTD schedule or CAISO Forecast of BAA Demand for the CAISO used in the RTD from Day-Ahead Schedules; and (c) the balanced contract quantity mentioned in Section 11.5.7.1.

### 11.5.8 Settlement for Emergency Assistance

This Section 11.5.8 shall apply to Settlement for emergency assistance provided to or by the CAISO. In any case in which the CAISO has entered into an agreement regarding emergency assistance, which agreement has been accepted by FERC, the provisions of the agreement shall prevail over any conflicting provisions of this Section 11.5.8. Where the provisions of this Section 11.5.8 do not conflict with the provisions of the FERC-accepted agreement, the provisions of this Section 11.5.8 shall apply to the subject emergency assistance.

**11.5.8.1 Settlement for Energy Purchased by the CAISO for System Emergency Conditions, to Avoid Market Disruption, or to Prevent or Relieve Imminent System Emergencies, Other than Exceptional Dispatch Energy**

The Settlement price for Energy that is delivered to the CAISO from a utility in another Balancing Authority Area as a result of a CAISO request pursuant to Section 42.1.5 or any other provision for assistance in System Emergency conditions, to avoid a Market Disruption, or to prevent or relieve an imminent System Emergency, other than Energy from an Exceptional Dispatch, shall be either (i) a negotiated price agreed upon by the CAISO and the seller or (ii) a price established by the seller for such emergency assistance in advance, as may be applicable. In the event no Settlement price is established prior to the delivery of the emergency Energy, the default Settlement price shall be the simple average of the relevant FMM and RTD LMPs at the applicable Scheduling Point, plus all other charges applicable to imports to the CAISO Balancing Authority Area, as specified in the CAISO Tariff. If the default Settlement price is determined by the seller not to compensate the seller for the value of the emergency Energy delivered to the CAISO, then the seller shall have the opportunity to provide the CAISO with cost support information demonstrating that a higher price is justified. The cost support information must be provided in writing to the CAISO within thirty (30) days following the date of the provision of emergency assistance. The CAISO shall have the discretion to pay that higher price based on the seller’s justification of this higher price. The CAISO will provide notice of its determination whether to pay such a higher price within thirty (30) days after receipt of the cost support information. Any dispute regarding the CAISO's determination whether to pay a higher price for emergency assistance based on cost support information shall be subject to the CAISO ADR Procedures. Payment by the CAISO for such emergency assistance will be made in accordance with the Settlement process, billing cycle, and payment timeline set forth in the CAISO Tariff. The costs for such emergency assistance, including the payment of a price based on cost support information, will be settled in two payments: (1) the costs will first be settled at the simple average of the relevant Dispatch Interval LMPs and included in the total FMM IIE Settlement Amount and RTD IIE Settlement Amount as described in Sections 11.5.1.1 and 11.5.1.2; and (2) costs in excess of the simple average of the relevant Dispatch Interval LMPs plus other applicable charges will be settled in accordance with Section 11.5.8.1.1. The allocation of the FMM IIE Settlement Amount and RTD IIE Settlement Amount settled in accordance with Sections 11.5.1.1 and 11.5.1.2 will be settled according to Section 11.5.4.2.

**11.5.8.1.1 Settlement and Allocation of Excess Costs Payments for Emergency Energy Purchases, Other than Exceptional Dispatch Energy, to Scheduling Coordinators**

The Excess Cost Payments for emergency Energy purchased in the circumstances specified in Section 11.5.8.1 is calculated for each purchase for each Settlement Interval as the cost difference between the Settlement amount calculated pursuant to Section 11.5.8.1 for the delivered purchase quantity and the simple average of the relevant Dispatch Interval LMPs at the applicable Scheduling Point. The Excess Cost Payments for emergency Energy purchased in the circumstances specified in Section 11.5.8.1 shall be allocated in the same manner as specified in Section 11.5.6.2.5.2 for the allocation of the Excess Cost Payments portion of payments for Exceptional Dispatches for emergency conditions.

**11.5.8.2 Settlement for Energy Supplied by the CAISO in Response to a Request for Emergency Assistance**

The Settlement price for emergency Energy that is delivered by the CAISO to a utility in another Balancing Authority Area in response to a request for emergency assistance shall be the simple average of the relevant Dispatch Interval LMPs at the applicable Scheduling Point, which shall serve as the effective market price for that Energy, plus all other charges applicable to exports from the CAISO Balancing Authority Area, as specified in the CAISO Tariff and will be included in the total FMM IIE Settlement Amount and RTD IIE Settlement Amount as described in Sections 11.5.1.1 and 11.5.1.2 and will be allocated according to Section 11.5.4.2. Such price may be estimated prior to delivery and finalized in the Settlement process. The CAISO will establish a Scheduling Coordinator account, if necessary, for the purchaser for the sole purpose of facilitating the Settlement of such emergency assistance. Payment to the CAISO for such emergency assistance shall be made in accordance with the Settlement process, billing cycle, and payment timeline set forth in the CAISO Tariff.

### 11.5.9 Flexible Ramping Product

The CAISO will settle the Flexible Ramping Product as set forth in Section 11.25.

## 11.6 PDRs, RDRRs, Distributed Energy Resource Aggregations, Non-Generator Resources

### 11.6.1 Settlement of Energy Transactions Involving PDRs or RDRRs Using Customer Load Baseline Methodology

Settlements for Energy provided by Demand Response Providers from Proxy Demand Resources or Reliability Demand Response Resources shall be based on the Demand Response Energy Measurement for the Proxy Demand Resources or Reliability Demand Response Resources. The Demand Response Energy Measurement for a Proxy Demand Resource or Reliability Demand Response Resource shall be the quantity of Energy equal to the difference between the (i) Customer Load Baseline for the Proxy Demand Resource or Reliability Demand Response Resource and (ii) either the actual underlying consumption or the quantity of Energy calculated pursuant to Section 10.1.7 for the Proxy Demand Resource or Reliability Demand Response Resource for a Demand Response Event. Scheduling Coordinators will be responsible for calculating and submitting Demand Response Energy Measurements in 5-minute intervals. For monitoring, compliance, and audit purposes, Scheduling Coordinators must submit in the Settlement Quality Meter Data Systems the Customer Load Baseline, as applicable, and the actual underlying consumption or Energy during all hourly intervals for the calendar days for which the Meter Data was collected to develop the Customer Load Baseline pursuant to Section 4.13.4. Only Demand Response Energy Measurements will be considered Settlement Quality Meter Data. For such Proxy Demand Resources or Reliability Demand Response Resources, the Scheduling Coordinator will calculate the relevant Customer Load Baseline as set forth in Section 4.13.4. If the Proxy Demand Resource or Reliability Demand Response uses behind-the-meter generation to offset Demand, and has elected to always provide Meter Data consisting of its total gross consumption, the Demand Response Energy Measurement shall be the quantity of Energy equal to the difference between (i) the Customer Load Baseline, which derives from the gross consumption independent of offsetting Energy from behind-the-meter generation for the Proxy Demand Resource or Reliability Demand Response Resource, and (ii) the gross underlying consumption, independent of offsetting Energy from the behind-the-meter generation. Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources will only be settled in intervals where their total Expected Energy is above zero. Scheduling Coordinators may not submit Demand Response Energy Measurements in Settlement Intervals where the total Expected Energy did not exceed zero.

### 11.6.2 Settlement of Energy Transactions Using Metering Generator Output Methodology

Settlements for Energy provided by Demand Response Providers from registered behind-the-meter generation in Proxy Demand Resources or Reliability Demand Response Resources shall be based on their Demand Response Energy Measurement. The Demand Response Energy Measurement for Proxy Demand Resources or Reliability Demand Response Resources consisting of registered behind-the-meter generation shall be the quantity of Energy equal to the difference between (i) the Energy output of the Proxy Demand Resources or Reliability Demand Response Resources, and (ii) the Generator Output Baseline for the behind-the-meter generation registered in the Proxy Demand Resource or Reliability Demand Response Resource, which derives from the Energy output of the behind-the-meter generation only, independent of offsetting facility Demand. In calculating the Energy output of such generation, the Meter Data must represent the Energy output of the behind-the-meter generation up to the total facility Demand, but excluding output that would represent an export of Energy from that location in any Settlement Interval in which the behind-the-meter generation is exporting Energy (i.e., where the behind-the-meter generation Energy output exceeds its location Demand). For such behind-the-meter generation, the Generator Output Baseline will be calculated as set forth in Section 4.13.4.2. Demand Response Energy Measurements will be calculated and submitted in 5-minute intervals. In cases where the Demand Response Energy Measurements are less than zero within a 5-minute interval, that measurement will be submitted as zero. Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources will only be settled in intervals where their total Expected Energy is above zero.

### 11.6.3 Settlement of Energy Transactions Involving PDRs or RDRRs Using Customer Load Baseline and Metering Generator Output Methodologies

Settlements for Energy provided by Demand Response Providers using Proxy Demand Resources or Reliability Demand Response Resources that include (i) separately metered, registered behind-the-meter generation Energy output Meter Data, exclusive of facility consumption data pursuant to Sections 4.13.4.2 and 11.6.2, and Proxy Demand Resources or Reliability Demand Response Resources that (ii) reduce consumption independent and separately metered from offsetting behind-the-meter generation pursuant to Sections 4.13.4 and 11.6.1, shall be the sum of the Demand Response Energy Measurements for the Proxy Demand Resources or Reliability Demand Response Resources as if they were settled separately and independently pursuant to Sections 11.6.1 and 11.6.2. Demand Response Energy Measurements will be calculated and submitted in 5-minute intervals. Demand Response Energy Measurements for Proxy Demand Resources and Reliability Demand Response Resources will only be settled in intervals where their total Expected Energy is above zero.

### 11.6.4 Settlements of Proxy Demand Resources and Reliability Demand Response Resources in the Real-Time Market

The CAISO will calculate RTM Schedules and Awards for Proxy Demand Resources and Reliability Demand Response Resources at the relevant RTM Locational Marginal Price at the relevant Scheduling Point consistent with Section 11.5. The portion of an Hourly Block

Schedule for Energy that becomes financially binding will constitute an FMM Schedule. A cleared

Economic Hourly Block Bid is not eligible for Bid Cost Recovery. Ramping Energy Deviations, Residual

Imbalance Energy, and Standard Ramping Energy do not apply to Proxy Demand Resources and Reliability Demand Response Resources with Hourly Block or FMM Schedules.

### 11.6.5 Settlement of Distributed Energy Resource Aggregations

Settlements for Energy provided by a Distributed Energy Resource Provider from a Distributed Energy Resource Aggregation shall be based on the applicable PNode or Aggregated PNode of the Distributed Energy Resource Aggregation. For Distributed Energy Resource Aggregations comprising a single PNode, settlement for Energy transactions would reflect the LMP at that PNode. For Distributed Energy Resource Aggregations comprising multiple PNodes settlement for Energy transactions would be the weighted average LMP of the PNode(s) based on the applicable Generation Distribution Factors submitted through the Distributed Energy Resource Aggregation’s Bid or as registered in the Master File. Consistent with the provisions of Section 11.5.2, the CAISO will impose UIE on a Distributed Energy Resource Provider if the Distributed Energy Resource Provider’s Distributed Energy Resource Aggregation does not follow a Dispatch Instruction.

### 11.6.6 Settlements of Non-Generator Resources

Settlements for Energy generated or consumed by a Non-Generator Resource or a resource using Non-Generator Resource Generic Modeling functionality will reflect the applicable PNode or Aggregated PNode. For such resources comprising a single PNode, settlement for Energy transactions will reflect the LMP at that PNode. For such resources comprising multiple PNodes settlement for Energy transactions will reflect the weighted average LMP of the PNode(s) based on the applicable Generation Distribution Factors submitted through the resources’ Bid or as registered in the Master File. Consistent with the provisions of Section 11.5.2, the CAISO will impose UIE on a resource’s Scheduling Coordinator if the resource does not follow a Dispatch Instruction. When operating in a negative range between PMin and 0, the CAISO will not consider a Non-Generator Resource or a resource using Non-Generator Resource Generic Modeling functionality as Measured Demand so long as the resource can generate Energy. If a Non-Generator Resource operates solely as dispatchable demand response, the CAISO will treat the resource as Measured Demand.

Where Scheduling Coordinators elect to submit end-of-hour state-of-charge targets, storage resources participating as Non-Generator Resources will be ineligible for RTM Bid Cost Shortfalls in the two hours preceding the scheduled Operating Hour. Where Scheduling Coordinators elect to submit Self-Schedules in the CAISO Real-Time Markets, storage resources participating as Non-Generator Resources will be ineligible for RTM Bid Cost Shortfalls in the hour preceding the scheduled Operating Hour. Where the CAISO dispatches storage resources participating as Non-Generator Resources to charge or discharge pursuant to Sections 8.4.1.1(g) or 8.4.3 for the Real-Time Market, they will be ineligible for RTM Bid Cost Shortfalls.

### 11.6.7 Settlement of Proxy Demand Resources using the Load-Shift Methodology

The CAISO will settle separately the consumption Resource ID and curtailment Resource ID of a Proxy Demand Resource using the load-shift methodology. The Demand Response Energy Measurement for the consumption Resource ID will be the quantity of Energy equal to the difference between (i) its Customer Load Baseline calculated pursuant to Section 4.13.4.7 and (ii) its actual underlying negative Energy for a Demand Response Event. The Demand Response Energy Measurement for the curtailment Resource ID will be the quantity of Energy from the behind-the-meter energy storage equal to the difference between (i) its Generator Output Baseline calculated pursuant to Section 4.13.4.7 and (ii) its actual underlying production for a Demand Response Event. If the Proxy Demand Resource elects to curtail local onsite Demand independent of the behind-the-meter energy storage, the Scheduling Coordinator will add the Demand Response Energy Measurement calculated for the onsite Load pursuant to this Section 11.6 to the Demand Response Energy Measurement of the curtailment Resource ID. Scheduling Coordinators will be responsible for calculating and submitting Demand Response Energy Measurements in 5-minute intervals. For monitoring, compliance, and audit purposes, Scheduling Coordinators must submit in the Settlement Quality Meter Data Systems the Generator Output and Customer Load Baselines, as applicable, and the actual underlying consumption or Energy during all hourly intervals for the calendar days for which the Meter Data was collected to develop them pursuant to Section 4.13.4. Only Demand Response Energy Measurements will be considered Settlement Quality Meter Data. Demand Response Energy Measurements for Proxy Demand Resources will only be settled in intervals where their total Expected Energy is above zero. The CAISO will calculate the respective bid cost recoveries for each Resource ID consistent with Section 11.8. The consumption Resource ID will not recover Start-Up Costs, Minimum Load Costs, Pumping Costs, Pump Shut-Down Costs, or Transition Costs, but may recover Energy Bid Costs.

## 11.7 Additional MSS Settlements Requirements

### 11.7.1 MSS Load Following Deviation Penalty

For MSS Operators that have elected to follow their Load as described in Section 4.9.13.2, the Scheduling Coordinator for a Load following MSS Operator shall pay amounts for: (i) excess MSS Generation supplied to the CAISO Markets and (ii) excess MSS Load relying on CAISO Markets and not served by MSS generating resources. The revenue received from these payments will be used as an off-set to the CAISO’s Grid Management Charge. The payments due from a Scheduling Coordinator will be calculated as follows:

**11.7.1.1** If the metered Generation resources and imports into the MSS exceed: (i) the metered Demand and exports from the MSS; and (ii) Energy expected to be delivered by the Scheduling Coordinator for the MSS in response to the CAISO’s Dispatch Instructions and/or Regulation Set Point signals issued by the CAISO’s AGC by more than the MSS Deviation Band, then the payment for excess Energy outside of the MSS Deviation Band shall be rescinded and Scheduling Coordinator for the MSS Operator will pay the CAISO an amount equal to one hundred percent (100%) of the product of the highest LMP paid to the MSS Operator for its Generation in the Settlement Interval and the amount of the FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy that is supplied in excess of the MSS Deviation Band.

**11.7.1.2** If metered Generation resources and imports into the MSS are insufficient to meet: (i) the metered Demand and exports from the MSS; and (ii) Energy expected to be delivered by the Scheduling Coordinator for the MSS in response to the CAISO’s Dispatch Instructions and/or Regulation Set Point signals issued by the CAISO’s AGC by more than the MSS Deviation Band, then the Scheduling Coordinator for the MSS Operator shall pay the CAISO an amount equal to the product of the Default LAP price for the Settlement Interval and two hundred percent (200%) of the shortfall that is outside of the MSS Deviation Band. The payment in the previous sentence is in addition to the charges for the FMM Instructed Imbalance Energy and RTD Instructed Imbalance Energy that serves the excess MSS Demand that may be applicable under Section 11.5.

### 11.7.2 Neutrality Adjustments and Charges Assessed on MSS SC

The CAISO will assess the Scheduling Coordinator for the MSS the neutrality adjustments and Existing Contracts cash neutrality charges pursuant to Section 11.14 (or collect refunds therefrom) based on the net Measured Demand of the MSS.

### 11.7.3 Available MSS Operator Exemption for Certain Program Charges

If the CAISO is charging Scheduling Coordinators for summer reliability or Demand reduction programs, the MSS Operator may petition the CAISO for an exemption of these charges. If the MSS Operator provides documentation to the CAISO by November 1 of any year demonstrating that the MSS Operator has secured capacity reserves for the following calendar year at least equal to one hundred and fifteen percent (115%), on an annual basis, of the peak Demand responsibility of the MSS Operator, the CAISO shall grant the exemption. Eligible capacity reserves for such a demonstration may include on-demand rights to Energy, peaking resources, and Demand reduction programs. The peak Demand responsibility of the MSS Operator shall be equal to the annual peak Demand Forecast of the MSS Load plus any firm power sales by the MSS Operator, less interruptible Loads, and less any firm power purchases. Firm power for the purposes of this Section 11.7.3 shall be Energy that is intended to be available to the purchaser without being subject to interruption or curtailment by the supplier except for Uncontrollable Forces or emergency. To the extent that the MSS Operator demonstrates that it has secured capacity reserves in accordance with this Section 11.7.3, the Scheduling Coordinator for the MSS Operator shall not be obligated to bear any share of the CAISO’s costs for any summer Demand reduction program or for any summer reliability Generation procurement program pursuant to Section 42.1.8 for the calendar year for which the demonstration is made.

### 11.7.4 Emission Cost Responsibility of an SC for an MSS

Unless specified otherwise in the MSS agreement(s), if the CAISO is compensating Generating Units for Emissions Costs, and if an MSS Operator charges the CAISO for the Emissions Costs of the Generating Units serving the Load of the MSS, then the Scheduling Coordinator for the MSS shall bear its proportionate share of the total amount of those costs incurred by the CAISO based on the MSS gross Measured Demand excluding out of state exports and the Generating Units shall be made available to the CAISO through the submittal of Energy Bids. If the MSS Operator chooses not to charge the CAISO for the Emissions Costs of the Generating Units serving the Load of the MSS, then the Scheduling Coordinator for the MSS shall bear its proportionate share of the total amount of those costs incurred by the CAISO based on the MSS's net Measured Demand excluding out-of-state exports. For MSS Operators that have elected to follow their Load, and if an MSS Operator chooses not to charge the CAISO for the Emissions Costs of the Generating Units serving that MSS Operator’s Load, then that MSS’s Scheduling Coordinator for that Load shall bear its proportionate share of the total amount of those costs incurred by the CAISO based on that MSS’s Net Negative Uninstructed Deviations with Load Following Energy included in the netting. The MSS Operator shall make the election whether to charge the CAISO for these costs on an annual basis on November 1 for the following calendar year.

## 11.8 Bid Cost Recovery

For purposes of determining the Unrecovered Bid Cost Uplift Payments for each Bid Cost Recovery Eligible Resource as determined in Section 11.8.5 and the allocation of Unrecovered Bid Cost Uplift Payments for each Settlement Interval, the CAISO shall sequentially calculate the Bid Costs, which can be positive (IFM Bid Cost Shortfall, RUC Bid Cost Shortfall, or RTM Bid Cost Shortfall) or negative (IFM Bid Cost Surplus, RUC Bid Cost Surplus, or RTM Bid Cost Surplus) in the IFM, RUC, and the Real-Time Market, as the algebraic difference between the respective IFM Bid Cost, RUC Bid Cost or RTM Bid Cost and the IFM Market Revenues, RUC Market Revenues, or RTM Market Revenues as further described below in this Section 11.8. The RTM Energy Bid Costs and RTM Market Revenues include the FMM Energy Bid Costs. In any Settlement Interval a resource is eligible for Bid Cost Recovery payments pursuant to the rules described in the subsections of Section 11.8 and Section 11.17. Bid Cost Recovery Eligible Resources for different MSS Operators are supply resources listed in the applicable MSS Agreement. All Bid Costs shall be based on Bids as mitigated pursuant to the requirements specified in Section 39.7. Virtual Awards are not eligible for Bid Cost Recovery. Virtual Awards are eligible for make-whole payments due to price corrections pursuant to Section 11.21.2. In order to be eligible for Bid Cost Recovery, Non-Dynamic Resource-Specific System Resources must provide to the CAISO SCADA data by telemetry to the CAISO’s EMS in accordance with Section 4.12.3 demonstrating that they have performed in accordance with their CAISO commitments. Scheduling Coordinators for Non-Generator Resources are not eligible to recover Start-Up Bid Costs, Minimum Load Bid Costs, Pumping Costs, Pump Shut-Down Costs, or Transition Bid Costs but are eligible to recover Energy Bid Costs, RUC Availability Payments and Ancillary Service Bid Costs.

### 11.8.1 CAISO Determination of Self-Commitment Periods

For the purposes of identifying the periods during which a Bid Cost Recovery Eligible Resource is deemed self-committed and thus ineligible for Start-Up Bid Costs, Transition Bid Costs, Minimum Load Bid Costs, IFM Pump Shut-Down Costs and IFM Pumping Costs, the CAISO derives the Self-Commitment Periods as described below. The CAISO will determine the Self-Commitment Periods for Multi-Stage Generating Resources based on the applicable MSG Configuration. MSS resources designated for Load following are considered to be self-committed if they have been scheduled with non-zero Load following capacity, or are otherwise used to follow Load in the Real-Time. The IFM Self-Commitment Period and RUC Self-Commitment Period will be available as part of the Day-Ahead Market results provided to the applicable Scheduling Coordinator. The interim RTM Self-Commitment Periods as reflected in the RTM will be available as part of the RTM results for the relevant Trading Hour as provided to the applicable Scheduling Coordinator. The final RTM Self-Commitment Period is determined ex-post for Settlements purposes. ELS Resources committed through the ELC Process described in Section 31.7 are considered to have been committed in the IFM Commitment Period for the applicable Trading Day for the purposes of determining BCR settlement in this Section 11.8.

**11.8.1.1 IFM Self-Commitment Period**

An IFM Self-Commitment Period for a Bid Cost Recovery Eligible Resource shall consist of one or more sets of consecutive Trading Hours during which the relevant Bid Cost Recovery Eligible Resource has either a Self-Schedule or, except for Self-Provided Ancillary Services for Non-Spinning Reserve by a Short Start Unit, has a non-zero amount of Self-Provided Ancillary Services. An IFM Self-Commitment Period for a Bid Cost Recovery Eligible Resource may not be less than the relevant Minimum Run Time (MRT), rounded up to the next hour. Consequently, if a Bid Cost Recovery Eligible Resource first self-commits in hour h of the Trading Day, the self-commitment will be extended to hour h + MRT. Two IFM Self-Commitment Periods for a Bid Cost Recovery Eligible Resource may not be apart by less than the relevant Minimum Down Time (MDT) (rounded up to the next hour). Consequently, if a Bid Cost Recovery Eligible Resource has submitted a Self-Schedule or Submission to Self-Provide an Ancillary Service in hours h and h + n, and n is less than the MDT, the IFM Self-Commitment Period will be extended to the hours in between h and h + n inclusive. The number of IFM Self-Commitment Periods for a Bid Cost Recovery Eligible Resource within a Trading Day cannot exceed the relevant Maximum Daily Start-Ups (MDS), or MDS + 1 if the first IFM Self-Commitment Period is the continuation of an IFM or RUC Commitment Period from the previous Trading Day. Consequently, if a Bid Cost Recovery Eligible Resource has submitted a Self-Schedule or Submission to Self-Provide an Ancillary Service, such that after applying the preceding two rules, the number of disjoint Self Commitment Periods for the Operating Day exceeds the Maximum Daily Start-Ups (MDS), or MDS + 1 if the first IFM Self-Commitment Period is the continuation of an IFM or RUC Commitment Period from the previous Trading Day, the disjoint Self Commitment Periods with smallest time gap in between will be joined together to bring down the number of disjoint Self Commitment Periods to MDS or MDS +1 as relevant. To determine whether an extension of the IFM Self-Commitment Period applies for Multi-Stage Generating Resources, the CAISO will ensure that the respective Minimum Run Time and Minimum Down Time for both the Generating Unit and MSG Configuration levels are simultaneously respected.

**11.8.1.2 Real-Time Self-Commitment Period**

A Real-Time Market Self-Commitment Period for a Bid Cost Recovery Eligible Resource shall consist of all consecutive Dispatch Intervals not in an IFM Commitment Period or a RUC Commitment Period where the Bid Cost Recovery Eligible Resource has a Self-Schedule or, except for Self-Provided Ancillary Services for Non-Spinning Reserve by a Short Start Unit, has a non-zero amount of Self-Provided Ancillary Services. A Real-Time Market Self-Commitment Period for a Bid Cost Recovery Eligible Resource may not be less than the relevant MUT (rounded up to the next 15-minute Commitment Interval) when considered jointly with any adjacent IFM Self-Commitment Period. For example, if a Bid Cost Recovery Eligible Resource self-commits at time h, the self-commitment will be extended to Commitment Interval h + MUT, unless an IFM or RUC Commitment Period exists starting after hour h, in which case the self-commitment will be extended to Commitment Interval h + min (MUT, t), where t represents the time interval between the Real-Time Market Self-Commitment Period and the IFM or RUC Commitment Period. A Real-Time Market Self-Commitment Period for a Bid Cost Recovery Eligible Resource may not be apart from an IFM or RUC Commitment Period by less than the relevant MDT (rounded up to the next 15-minute Commitment Interval). To determine whether an extension of the RTM Self-Commitment Period applies for Multi-Stage Generating Resources, the CAISO will ensure that the respective Minimum Run Time and Minimum Down Time for both the Generating Unit and MSG Configuration levels are simultaneously respected.

**11.8.1.3 Multi-Stage Generating Resource Start-Up Bid Costs, Minimum Load Bid Costs, or Transition Bid Costs**

For the settlement of the Multi-Stage Generating Resource Start-Up Bid Costs, Minimum Load Bid Costs, and Transition Bid Costs in the IFM, RUC, and RTM, the CAISO will determine the applicable Commitment Period and select the applicable Start-Up Bid Costs, Minimum Load Bid Costs, and Transition Bid Costs based on the following rules.

(1) In any given Settlement Interval, the CAISO will first apply the following rules to determine the applicable Start-Up Bid Costs and Transition Bid Costs for the Multi-Stage Generating Resources. For a Commitment Period in which:

(a) the IFM Commitment Period and/or RUC Commitment Period MSG Configuration(s) are different from the RTM CAISO Commitment Period MSG Configuration, the Multi-Stage Generating Resource’s Start-Up Bid Cost and Transition Bid Cost will be settled based on the RTM CAISO Commitment Period MSG Configuration Start-Up Bid Costs, and Transition Bid Costs, as described in Section 11.8.4.1.

(b) there is a CAISO IFM Commitment Period and/or CAISO RUC Commitment Period in any MSG Configuration and there is also a RTM Self-Commitment Period in any MSG Configuration, the Multi-Stage Generating Resource’s Start-Up Bid Costs and Transition Bid Costs will be settled based on the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration(s) Start-Up Bid Costs and Transition Bid Costs, as described in Sections 11.8.2.1 and 11.8.3.1, and further determined pursuant to part (2) of this Section below.

(c) the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration is the same as the CAISO RTM Commitment Period MSG Configuration, the Multi-Stage Generating Resource’s Start-Up Bid Costs and Transition Bid Costs will be settled based on the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration(s) Start-Up Bid Costs and Transition Bid Costs described in Sections 11.8.2.1 and 11.8.3.1, and further determined pursuant to part (3) of this Section below.

(d) the IFM Self-Commitment Period and RUC Self-Commitment Period MSG Configuration(s) are the same as the CAISO RTM Commitment Period MSG Configuration, then the Multi-Stage Generating Resource’s Start-Up Bid Costs and Transition Bid Costs will be settled based on the CAISO RTM Commitment Period MSG Configuration Start-Up Bid Costs and Transition Bid Costs as described in Section 11.8.4.1.

(2) For the purpose of determining which MSG Configuration Minimum Load Bid Costs will apply in any given Commitment Interval, the CAISO will apply the following rules.

(a) If there is a CAISO IFM Commitment Period and/or CAISO RUC Commitment Period, the CAISO will calculate the IFM Minimum Load Costs and/or RUC Minimum Load Costs, pursuant to Section 11.8.2.1 or 11.8.3.1, respectively, based on the MSG Configuration committed in the IFM or RUC.

(b) For purposes of determining the MSG Configuration Minimum Load Bid Costs included in the RTM Minimum Load Costs calculated pursuant to Section 11.8.4.1.2, the CAISO will use the difference between the amounts determined under (i) and (ii) below.

(i) The CAISO will calculate the RTM MSG Configuration Minimum Load Bid Costs as the RTM Minimum Load Cost attributed to the MSG Configuration committed in the RTM, whether that MSG Configuration is Self-Scheduled or CAISO-committed.

(ii) The CAISO will determine one of the two applicable amounts:

a. If there is a Real-Time Market Self-Schedule, the maximum of (A) the Minimum Load Bid Costs attributed to the MSG Configuration either self-Scheduled or CAISO-committed in the IFM or RUC; and (B) the Minimum Load Cost attributed to the MSG Configuration Self-Scheduled in the RTM.

b. If there is no Real-Time Market Self-Schedule, the Minimum Load Bid Costs attributed to the MSG Configuration either self-Scheduled or CAISO-committed in the IFM or RUC.

(3) In any given Settlement Interval, after the rules specified in part (1) and (2) above of this Section have been executed, the CAISO will apply the following rules to determine whether the IFM Start-Up Cost or RUC Start-Up Cost, IFM Minimum Load Cost or RUC Minimum Load Cost, and IFM Transition Cost or RUC Transition Cost apply for Multi-Stage Generating Resources. For a Commitment Period in which:

(a) the IFM Commitment Period MSG Configuration is different from the CAISO RUC Commitment Period MSG Configuration the Multi-Stage Generating Resource’s Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost will be settled based on the CAISO RUC Commitment Period MSG Configuration Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost as described in Section 11.8.3.1.

(b) the CAISO IFM Commitment Period MSG Configuration is the same as the CAISO RUC Commitment Period MSG Configuration, the Multi-Stage Generating Resource’s Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost will be based on the CAISO IFM Commitment Period MSG Configuration Start-Up Bid Cost, Minimum Load Bid Cost, and Transition Bid Cost as described in Section 11.8.2.1.

### 11.8.2 IFM Bid Cost Recovery Amount

For purposes of determining the IFM Unrecovered Bid Cost Uplift Payments as determined in Section 11.8.5, and the purposes of allocating Net IFM Bid Cost Uplift as described in Section 11.8.6.4, the CAISO shall calculate the IFM Bid Cost Shortfall or the IFM Bid Cost Surplus as the algebraic difference between the IFM Bid Cost and the IFM Market Revenues for each Settlement Interval, which are determined as described below and subject to the application of the Day-Ahead Metered Energy Adjustment Factor and the Real-Time Performance Metric rules specified in Section 11.8.2.5 and 11.8.4.4, respectively. The IFM Bid Costs shall be calculated pursuant to Section 11.8.2.1 and the IFM Market Revenues shall be calculated pursuant to Section 11.8.2.2.

**11.8.2.1 IFM Bid Cost Calculation**

For each Settlement Interval, the CAISO shall calculate IFM Bid Cost for each Bid Cost Recovery Eligible Resource as the algebraic sum of the IFM Start-Up Cost, IFM Transition Cost, IFM Minimum Load Cost, IFM Pump Shut-Down Cost, IFM Energy Bid Cost, IFM Pumping Cost, IFM AS Bid Cost, and IFM Imbalance Reserves Cost. For Multi-Stage Generating Resources, in addition to the specific IFM Bid Cost rules described in Section 11.8.2.1, the CAISO will apply the rules described in Section 11.8.1.3 to further determine the applicable MSG Configuration-based CAISO Market Start-Up Bid Cost, Transition Bid Cost, and Minimum Load Bid Cost in any given Settlement Interval. For Multi-Stage Generating Resources, the incremental IFM Start-Up Costs, IFM Minimum Load Costs, and IFM Transition Costs to provide Energy Scheduled in the Day-Ahead Schedule or awarded RUC or Ancillary Service capacity for an MSG Configuration other than the self-scheduled MSG Configuration are determined by the IFM rules specified in Section 31.3. For RMR Resources, the CAISO shall calculate the IFM Bid Cost as the algebraic sum of the IFM Start-Up Cost adjusted to remove Opportunity Costs, IFM Transition Cost adjusted to remove Opportunity Costs, IFM Minimum Load Costs adjusted to remove Opportunity Costs, IFM Energy Bid Cost adjusted to remove Opportunity Costs, and IFM AS Bid Cost. The CAISO will also adjust the IFM Bid Costs for RMR Resources, to remove any bid adder that includes costs that were recovered under the RMR Contract.

**11.8.2.1.1 IFM Start-Up Cost**

The IFM Start-Up Cost for any IFM Commitment Period shall be equal to the Start-Up Bid Costs applicable to the IFM divided by the number of Settlement Intervals within the applicable IFM Commitment Period. For each Settlement Interval, only the IFM Start-Up Cost in a CAISO IFM Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the IFM Start-Up Costs for Multi-Stage Generating Resources based on the CAISO-committed MSG Configuration. The following rules shall apply sequentially to qualify the IFM Start-Up Cost in an IFM Commitment Period:

(a) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if there is an IFM Self-Commitment Period within or overlapping with that IFM Commitment Period.

(b) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if the Bid Cost Recovery Eligible Resource is manually pre-dispatched under a Legacy RMR Contract prior to the Day-Ahead Market or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule in the Day-Ahead Market anywhere within the applicable IFM Commitment Period.

(c) The IFM Start-Up Cost for an IFM Commitment Period shall be zero if there is no actual Start-Up at the start of the applicable IFM Commitment Period because the IFM Commitment Period is the continuation of an IFM Commitment Period, RUC Commitment Period, or RTM Commitment Period from the previous Trading Day.

(d) If an IFM Start-Up is terminated in the Real-Time within the applicable IFM Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource was starting up, the IFM Start-Up Cost for that IFM Commitment Period shall be prorated by the ratio of the Start-Up Time before termination over the total IFM Start-Up Time.

(e) The IFM Start-Up Cost is qualified if an actual Start-Up occurs within the applicable IFM Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates the unit is Off before the time the resource is instructed to be On as specified in its Start-Up Instruction and is On in the Settlement Intervals that fall within the CAISO IFM Commitment Period. The CAISO will determine whether the resource is On for this purpose based on whether the resource’s metered Energy is at or above the resource’s Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3.

(f) The IFM Start-Up Cost will be qualified if an actual Start-Up occurs earlier than the start of the IFM Commitment Period if the advance Start-Up is a result of a Start-Up instruction issued in a RUC or Real-Time Market process subsequent to the IFM, or the advance Start-Up is uninstructed but is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the targeted IFM Start-Up.

(g) The Start- Up Bid Costs for a Bid Cost Recovery Eligible Resource that is a Short Start Unit committed by the CAISO in the IFM and that further receives a Start-Up Instruction from the CAISO in the Real-Time Market to start within the same CAISO IFM Commitment Period, will be qualified for the CAISO IFM Commitment Period instead of being qualified for the CAISO RTM Commitment Period; and Start-Up Bid Costs for subsequent Start-Ups will be further qualified as specified in Section 11.8.4.1.1(h).

**11.8.2.1.2 IFM Minimum Load Cost**

The IFM Minimum Load Cost for the applicable Settlement Interval shall be the Minimum Load Bid Cost applicable to the Integrated Forward Market, divided by the number of Settlement Intervals in a Trading Hour subject to the rules described below.

(a) For each Settlement Interval, only the IFM Minimum Load Cost in a CAISO IFM Commitment Period is eligible for Bid Cost Recovery.

(b) The IFM Minimum Load Cost for any Settlement Interval is zero if: (1) the Settlement Interval is in an IFM Self Commitment Period for the Bid Cost Recovery Eligible Resource; or (2) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under a Legacy RMR Contract prior to the Day-Ahead Market or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule for the applicable Settlement Interval.

(c) If the CAISO commits a Bid Cost Recovery Eligible Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the IFM Minimum Load Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. If the CAISO commits an RMR Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the sum of IFM Minimum Load Costs, adjusted to remove Minimum Load Opportunity Costs and Variable Minimum Load Operations and Maintenance Adders, are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4.

(d) If a Multi-Stage Generating Resource is committed by the CAISO and receives a Day-Ahead Schedule and subsequently is committed by the CAISO to a lower MSG Configuration where its Minimum Load capacity as registered in the Master File in the Real-Time Market is lower than the CAISO IFM Commitment Period MSG Configuration’s Minimum Load as registered in the Master File, the resource’s IFM Minimum Load Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. If the CAISO commits an RMR Multi-Stage Generating Resource in the Day-Ahead and the resource receives a Day-Ahead Schedule and the CAISO subsequently de-commits the resource in the Real-Time Market, the sum of IFM Minimum Load Costs, adjusted to remove Minimum Load Opportunity Costs and Variable Minimum Load Operations and Maintenance Adders, are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4.

(e) If the conditions in Sections 11.8.2.1.2 (c) and (d) do not apply, then the IFM Minimum Load Cost for any Settlement Interval is zero if the Bid Cost Recovery Eligible Resource is determined to be Off during the applicable Settlement Interval. For the purposes of determining IFM Minimum Load Cost, a Bid Cost Recovery Eligible Resource is assumed to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its (i) Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and (ii) the Tolerance Band, and the Metered Energy is greater than zero (0) MWh. Otherwise, such resource is determined to be Off.

(f) For Multi-Stage Generating Resources, the commitment period is determined based on application of section 11.8.1.3. If application of section 11.8.1.3 dictates that the IFM is the Commitment Period, then the calculation of the IFM Minimum Load Costs will depend on whether the IFM committed MSG Configuration is determined to be On. If it is determined to be On, then, the IFM Minimum Load Costs will be based on the Minimum Load Bid Costs of the IFM committed MSG Configuration. For the purposes of determining IFM Minimum Load Cost for a Multi-Stage Generating Resource, a Bid Cost Recovery Eligible Resource is determined to be On if its metered Energy in a Settlement Interval is equal to or greater than the difference between its IFM MSG Configuration Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and the Tolerance Band, and the Metered Energy is greater than zero (0) MWh. Otherwise, such resource is determined to be Off.

(g) The IFM Minimum Load Costs calculation is subject to the Shut-Down State Variable and is disqualified as specified in Section 11.17.2.

**11.8.2.1.3 IFM Pump Shut-Down Cost**

For Pumped-Storage Hydro Units and Participating Load only, the IFM Pump Shut-Down Costs for each Settlement Interval shall be equal to the relevant Pump Shut-Down Cost submitted to CAISO in the IFM divided by the number of Settlement Intervals in a Trading Hour that is preceded by a previous commitment by the IFM to pump, in which actual shut down occurs if the unit is committed by the IFM not to pump and actually does not operate in pumping mode in that Settlement Interval (as detected through Meter Data). The IFM Pump Shut-Down Cost for an IFM Shut-Down period shall be zero if: (1) it is followed by an IFM Self-Commitment Period or RTM Self-Commitment Period in generation mode; (2) the Shut-Down is due to an Outage reported through the CAISO’s outage management system as described in Section 9; or (3) the Shut-Down is delayed by the RTM past the IFM Shut-Down period in question or cancelled by the RTM before the Shut-Down process has started.

**11.8.2.1.4 IFM Pumping Bid Cost**

For Pumped-Storage Hydro Units and Participating Load only, the IFM Pumping Bid Cost for the applicable Settlement Interval shall be the Pumping Cost submitted to the CAISO in the IFM divided by the number of Settlement Intervals in a Trading Hour. The Pumping Cost is negative. The Pumping Cost is included in IFM Bid Cost computation for a Pumped-Storage Hydro Unit and Participating Load committed by the IFM to pump or serve Load if it actually operates in pumping mode or serves Load in that Settlement Interval. The IFM Energy Bid Cost for a Participating Load for any Settlement Interval is set to zero for actual Energy consumed in excess of the Day-Ahead Schedule for Demand. The IFM Pumping Cost for any Settlement Interval is zero if: (1) the Settlement Interval is in an IFM Self-Commitment Period for the Bid Cost Recovery Eligible Resource; or (2) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under a Legacy RMR Contract prior to the Day-Ahead Market or the resource is flagged as a Legacy RMR Dispatch in the Day-Ahead Schedule for the applicable Settlement Interval.

**11.8.2.1.5 IFM Energy Bid Cost**

For any Settlement Interval, the IFM Energy Bid Cost for Bid Cost Recovery Eligible Resources, except Participating Loads, shall be the integral of the relevant Energy Bid used in the IFM, if any, from the higher of the Bid Cost Recovery Eligible Resource’s Minimum Load as defined in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and the Day-Ahead Total Self-Schedule up to the relevant MWh scheduled in the Day-Ahead Schedule, divided by the number of Settlement Intervals in a Trading Hour. The IFM Energy Bid Cost calculations are subject to the application of the Day-Ahead Metered Energy Adjustment Factor, and the Persistent Deviation Metric pursuant to the rules specified in Section 11.8.2.5 and Section 11.17.2.3, respectively. In addition, if the CAISO commits a Bid Cost Recovery Eligible Resource in the Day-Ahead and receives a Day-Ahead Schedule and subsequently the CAISO de-commits the resource in the Real-Time Market, the IFM Energy Bid Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. If the CAISO commits a Multi-Stage Generating Resource in the Day-Ahead Market and the resource receives a Day-Ahead Schedule and subsequently the CAISO de-commits the Multi-Stage Generating Resource to a lower MSG Configuration where its Minimum Load capacity as registered in the Master File in the Real-Time Market is lower than the CAISO IFM Commitment Period MSG Configuration’s Minimum Load as registered in the Master File, the resource’s IFM Energy Bid Costs are subject to the Real-Time Performance Metric for each case specified in Section 11.8.4.4. The CAISO will determine the IFM Energy Bid Cost for a Multi-Stage Generating Resource at the Generating Unit level. The IFM Energy Bid Cost for RMR Resources shall be the integral of the relevant Energy Bid used in the IFM adjusted to remove Opportunity Costs from the higher of the RMR Resource’s Minimum Load as defined in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and the Day-Ahead Total Self-Schedule up to the relevant MWh scheduled in the Day-Ahead Schedule, divided by the number of Settlement Intervals in a Trading Hour.

**11.8.2.1.6 IFM AS Bid Cost**

For any Settlement Interval, the IFM AS Bid Cost shall be the product of the IFM AS Award from each accepted IFM AS Bid and the relevant AS Bid Price, divided by the number of Settlement Intervals in a Trading Hour. The CAISO will determine and calculate IFM AS Bid Cost for a Multi-Stage Generating Resource at the Generating Unit level. The IFM AS Bid Cost shall also include Mileage Bid Costs. For any Settlement Interval, the IFM Mileage Bid Cost shall be the product of Instructed Mileage associated with a Day Ahead Regulation capacity award, as adjusted for accuracy consistent with Section 11.10.1.7, and the relevant Mileage Bid price, divided by the number of Settlement Intervals in a Trading Hour. The CAISO will determine and calculate IFM Mileage Bid Cost for a Multi-Stage Generating Resource at the Generating Unit level. For any Settlement Interval, the IFM AS Bid Cost for an RMR Resource shall be zero.

**11.8.2.1.7 IFM Transition Cost**

For each Settlement Interval, the IFM Transition Costs shall be based on the MSG Configuration to which the Multi-Stage Generating Resource is transitioning and is allocated to the CAISO Commitment Period of that MSG Configuration.

**11.8.2.1.7.1 IFM Transition Cost Applicability**

Within any eligible IFM CAISO Commitment Period determined pursuant to the rules specified in Section 11.8.1.3, the CAISO shall apply the IFM Transition Costs for the Settlement Intervals in which the Multi-Stage Generating Resource is actually transitioning from the “from” MSG Configuration and reaches the Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, of the “to” MSG Configuration to which the Multi-Stage Generating Resource is transitioning, subject to the Tolerance Band.

**11.8.2.1.8 IFM Imbalance Reserves Cost**

For any Settlement Interval, the IFM Imbalance Reserves Cost shall be the product of the IRU Bid price and IRU Bid quantity (as reduced by the unavailable IRU quantity calculated per Section 11.2.1.8.1) plus the product of the IRD Bid price and IRD Bid quantity (as reduced by the unavailable IRD quantity calculated per Section 11.2.1.8.2).

**11.8.2.2 IFM Market Revenue**

The CAISO will apply the following rules to calculate a Bid Cost Recovery Eligible Resource’s IFM Market Revenue used for purposes of calculating its IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses calculated pursuant to Section 11.8.2, and for purposes of allocating the Bid Cost Uplift pursuant to Section 11.8.6. The IFM Market Revenue calculations for both CAISO IFM Commitment Periods and Self-Committed Periods will be subject to the Day-Ahead Metered Energy Adjustment Factor pursuant to the rules specified in Section 11.8.2.5.

**11.8.2.2.1 CAISO IFM Commitment**

For any Settlement Interval in a CAISO IFM Commitment Period the IFM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of the four products specified below. In the case of a Multi-Stage Generating Resource, the CAISO will calculate the market revenue at the Generating Unit or Dynamic Resource-Specific System Resource level.

(1) The product of the delivered MWh in the relevant Day-Ahead Schedule in that Trading Hour (where for Pumped-Storage Hydro Units and Participating Load operating in the pumping mode or serving Load the MWh is negative), and the relevant IFM LMP, divided by the number of Settlement Intervals in a Trading Hour.

(2) The product of the IFM AS Award from each accepted IFM AS Bid and the relevant Resource-Specific ASMP, divided by the number of Settlement Intervals in a Trading Hour.

(3) The product of the IRU award (as reduced by the unavailable IRU quantity calculated per Section 11.2.1.8.1) and the Locational IRU Price.

(4) The product of the IRD award (as reduced by the unavailable IRD quantity calculated per Section 11.2.1.8.2) and the Locational IRD Price.

**11.8.2.2.2 Resource Self-Committed**

For any Settlement Interval in a IFM Self-Commitment Period the IFM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of: (1) the product of the MWh above the greater of Minimum Load and Self-Scheduled Energy, in the relevant Day-Ahead Schedule in that Trading Hour and the relevant IFM LMP, divided by the number of Settlement Intervals in a Trading Hour; and (2) the product of the IFM AS Award from each accepted IFM AS Bid and the relevant Resource-Specific ASMP, divided by the number of Settlement Intervals in a Trading Hour.

**11.8.2.3 IFM Bid Cost Recovery Amounts for Metered Subsystems**

The IFM Bid Cost Recovery for MSS Operators differs based on whether the MSS Operator has elected gross or net Settlement.

**11.8.2.3.1 MSS Elected Gross Settlement**

For an MSS Operator that has elected gross Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the IFM Bid Cost and the IFM Market Revenue are calculated similarly to non-MSS resources on an individual resource basis as described in Sections 11.8.2.1 and 11.8.2.2, respectively.

**11.8.2.3.2 MSS Elected Net Settlement**

For an MSS Operator that has elected net Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the Energy Bid Costs and revenues for IFM Bid Cost Recovery is settled at the MSS level. The IFM Bid Cost as described in Section 11.8.2.1 above and IFM Market Revenue as provided in Section 11.8.2.2 above, of each MSS will be, respectively, the total of the IFM Bid Costs and IFM Market Revenues over all BCR Eligible Resources within the MSS where each BCR Eligible Resource’s IFM Market Revenues for its Energy shall be calculated as described in Section 11.2.3.2 at the relevant IFM MSS price. The IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses for Energy and AS are first calculated separately for the MSS for each Trading Hour of the Trading Day with qualified Start-Up Bid Costs and qualified Minimum Load Bid Costs included in the IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses for Energy calculation. The MSS’s overall IFM Bid Cost Shortfall or IFM Bid Cost Surplus is then calculated as the algebraic sum of the IFM Bid Cost Shortfall or IFM Bid Cost Surplus for Energy and the IFM Bid Cost Shortfall or IFM Bid Cost Surplus for AS for each Trading Hour.

**11.8.2.4 Ramping for IFM Initial Conditions Self-Schedules**

The CAISO shall determine the net IFM Bid Cost surplus or net IFM Bid Cost shortage across all full ramp down periods that start with an initial condition at the start of the IFM or a full ramp period within a 24 hour day-ahead market associated with a Self-Schedule any time within the full ramp period. For such full ramp periods associated with an initial condition or Self-Schedule with a net IFM Bid Cost shortfall, the net IFM Energy Bid Cost shortfall will not be included in IFM Bid Cost calculations. For the full ramp periods with a net IFM Bid Cost surplus, the surplus will be included in IFM Bid Cost calculations. For full other ramp periods not associated with an initial condition or Self-Schedule with IFM Energy Bid Cost shortfall, the shortfall with be included in IFM Bid Cost calculations. The CAISO will identify the Trading Hours scheduled as full ramp up periods as of the first hour where the resource is ramping up at full ramp until the last hour where the resource is ramping up at full ramp. Likewise, a full ramp down period will be identified as of first hour where the resource is ramping down at full ramp until the last hour that the resource is ramping down at full ramp.

**11.8.2.5 Calculation and Application of the Day-Ahead Metered Energy Adjustment Factor to IFM Bid Costs and Market Revenues**

The CAISO will adjust for each Bid Cost Recovery Eligible Resource the IFM Energy Bid Cost and IFM Market Revenue calculations by multiplying the Day-Ahead Metered Energy Adjustment Factor with the amounts derived as specified in Sections 11.8.2.1.5 and 11.8.2.2, respectively. In addition, the CAISO will apply the Real-Time Performance Metric to the IFM Energy Bid Costs, IFM Minimum Load Costs IFM Pumping Costs and IFM Market Revenues, as described in 11.8.4.4. The CAISO will not apply the Day-Ahead Metered Energy Adjustment Factor to Non-Generator Resources.

**11.8.2.5.1 Calculation of Day-Ahead Metered Energy Adjustment Factor**

The CAISO will calculate the Day-Ahead Metered Energy Adjustment Factor for each BCR Eligible Resource through the following steps:

**a)** **For Generation Unit and Resource-Specific-System Resource scheduled by CAISO in the Day-Ahead Market**

Step 1: If the resource’s Effective Day-Ahead Scheduled Energy is greater than or equal to its Day-Ahead Minimum Load Energy, and is greater than zero, then the calculation will proceed to step two. Otherwise, the calculation will proceed to step six.

Step 2: If (1) the resource’s Metered Energy less Regulation Energy is less than its Day-Ahead Minimum Load Energy less the Tolerance Band; or (2) the resource’s Metered Energy less Regulation Energy is less than or equal to zero, then the Day-Ahead Metered Energy Adjustment Factor will be set to zero (0). Otherwise, the calculation will proceed to step three.

Step 3: If the absolute value of the result of the resource’s Metered Energy less its Regulation Energy less the Effective Day-Ahead Scheduled Energy, is less than or equal to the Performance Metric Tolerance Band, then the Day-Ahead Metered Energy Adjustment Factor will be set to one (1). Otherwise, the calculation will proceed to step four.

Step 4: If the resource’s Effective Day-Ahead Scheduled Energy less its Day-Ahead Minimum Load Energy is equal to zero, then the Day-Ahead Metered Energy Adjustment Factor will be set to one (1). Otherwise, the calculation will proceed to step five.

Step 5: The resource’s Day-Ahead Metered Energy Adjustment Factor will be the minimum of: (A) the number one (1); or (B) the maximum of (i) the number zero (0), and (ii) the ratio of the resource’s (a) Metered Energy less the Day-Ahead Minimum Load Energy and less the Regulation Energy, and (b) the Effective Day-Ahead Scheduled Energy, less the Day-Ahead Minimum Load Energy.

Step 6: If the resource’s Effective Day-Ahead Scheduled Energy is less than its Day-Ahead Minimum Load Energy and if the resource’s Effective Day-Ahead Scheduled Energy is greater than zero (0), then its Day-Ahead Metered Energy Adjustment Factor will be set to one (1). Otherwise, the calculation will proceed to step seven.

Step 7: If the Day-Ahead Scheduled Energy is positive and the resource’s Expected Energy is less than or equal to zero, and its Metered Energy is less than or equal to zero, then its Day-Ahead Metered Energy Adjustment Factor will be set to one (1). Otherwise, its Day-Ahead Metered Energy Adjustment Factor will be set to zero (0).

**b) Participating Load Pumped-Storage Hydro Units and Pumping Load scheduled by CAISO to pump in the Day-Ahead Market**

Step 1: If the Day-Ahead Pumping Energy is negative and its Expected Energy is negative, then its Day-Ahead Metered Energy Adjustment Factor will be the minimum of: (A) the number one (1); or (B) the maximum of (i) the number zero (0) and (ii) the ratio of the resource’s Metered Energy and its Expected Energy. Otherwise, proceed to step two.

Step 2: If the Day-Ahead Pumping Energy is negative and the resource’s Expected Energy is greater than or equal to zero, and its Metered Energy is greater than or equal to zero, then its Day-Ahead Metered Energy Adjustment Factor will be (1). Otherwise, its Day-Ahead Metered Energy Adjustment Factor will be set to zero (0).

**11.8.2.5.2 Application of Day-Ahead Metered Energy Adjustment Factor**

The CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Pumping Bid Costs in the same manner in which the CAISO applies the Day-ahead Metered Energy Adjustment Factor to the IFM Energy Bid Costs as specified in this Section 11.8.2.5.2 and its subsections.

**11.8.2.5.2.1** If the IFM Energy Bid Costs and the IFM Market Revenues for the amounts of Day-Ahead Scheduled Energy above the Bid Cost Recovery Eligible Resource’s Minimum Load are greater than or equal to zero (0), the CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Energy Bid Costs, but not the IFM Market Revenue.

**11.8.2.5.2.2** If the IFM Energy Bid Costs are greater than or equal to zero (0) and the IFM Market Revenues are negative, the CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to both the IFM Energy Bid Costs and IFM Market Revenues.

**11.8.2.5.2.3** If the IFM Energy Bid Costs are negative and IFM Market Revenues are greater or equal to zero, the CAISO will not apply the Day-Ahead Metered Energy Adjustment Factor to IFM Energy Bid Costs or IFM Market Revenues.

**11.8.2.5.2.4** If the IFM Energy Bid Costs and the IFM Market Revenues are both negative, the CAISO will apply the Day-Ahead Metered Energy Adjustment Factor to the IFM Market Revenues, but it will not apply it to the IFM Energy Bid Costs.

### 11.8.3 RUC Bid Cost Recovery Amount

For purposes of determining the RUC Unrecovered Bid Cost Uplift Payments as determined in Section 11.8.5 and for the purposes of allocating Net RUC Bid Cost Uplift as described in Section 11.8.6.5, the CAISO shall calculate the RUC Bid Cost Shortfall or the RUC Bid Cost Surplus as the algebraic difference between the RUC Bid Cost and the RUC Market Revenues for each Bid Cost Recovery Eligible Resource for each Settlement Interval. The RUC Bid Costs shall be calculated pursuant to Section 11.8.3.1 and the RUC Market Revenues shall be calculated pursuant to Section 11.8.3.2. The CAISO will include Bid Cost Recovery costs related to Short Start Units committed in Real-Time because of awarded RUC Capacity in RTM Compensation Costs. The CAISO excludes RUC Bid Costs and RUC Market Revenues from calculations under this Section 11.8.3 to the extent the costs or revenues relate to RA Capacity that overlaps with a RUC Award for RCU or RUC Award for RCD as calculated per the methodology identified in Section 11.2.6.2.2 or Section 11.2.6.2.4, respectively.

**11.8.3.1 RUC Bid Cost Calculation**

For each Settlement Interval, the CAISO shall determine the RUC Bid Cost for a Bid Cost Recovery Eligible Resource as the algebraic sum of the RUC Start-Up Cost, RUC Transition Cost, RUC Minimum Load Cost, and RUC Availability Bid Cost. For Multi-Stage Generating Resources, in addition to the specific RUC Bid Cost rules described in Section 11.8.3.1, the rules described in Section 11.8.1.3 will be applied to further determine the applicable MSG Configuration-based CAISO Market Start-Up Bid Costs, Transition Bid Costs, and Minimum Load Bid Costs. For Multi-Stage Generating Resources, the incremental RUC Start-Up Costs, RUC Minimum Load Costs, and RUC Transition Costs to provide RUC awarded capacity for an MSG Configuration other than the self-scheduled MSG Configuration are determined by the RUC optimization rules in specified in Section 31.5. For each Settlement Interval, the CAISO shall determine the RUC Bid Cost for an RMR Resource as the algebraic sum of the RUC Start-Up Cost adjusted to remove Opportunity Costs and Variable Start-Up Operations and Maintenance Adders, and RUC Transition Cost adjusted to remove Opportunity Costs and Variable Start-Up Operations and Maintenance Adders.

**11.8.3.1.1 RUC Start-Up Cost**

The RUC Start-Up Cost for any Settlement Interval in a RUC Commitment Period shall consist of Start-Up Bid Cost of the Bid Cost Recovery Eligible Resource for the applicable RUC Commitment Period divided by the number of Settlement Intervals in the applicable RUC Commitment Period. For each Settlement Interval, only the RUC Start-Up Cost in a CAISO RUC Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the RUC Start-Up Cost for a Multi-Stage Generating Resource based on the MSG Configuration committed by the CAISO in RUC.

The following rules shall be applied in sequence and shall qualify the RUC Start-Up Cost in a RUC Commitment Period:

(a) The RUC Start-Up Cost for a RUC Commitment Period is zero if there is an IFM Commitment Period within that RUC Commitment Period.

(b) The RUC Start-Up Cost for a RUC Commitment Period is zero if the Bid Cost Recovery Eligible Resource is manually pre-dispatched under an RMR Contract prior to the Day-Ahead Market or is flagged as an RMR Dispatch in the Day-Ahead Schedule anywhere within that RUC Commitment Period.

(c) The RUC Start-Up Cost for a RUC Commitment Period is zero if there is no RUC Start-Up at the start of that RUC Commitment Period because the RUC Commitment Period is the continuation of an IFM Commitment Period, RUC Commitment Period, or RTM Commitment Period from the previous Trading Day.

(d) The RUC Start-Up Cost for a RUC Commitment Period is zero if the Start-Up is delayed beyond the RUC Commitment Period in question or cancelled by the Real-Time Market prior to the Bid Cost Recovery Eligible Resource starting its start-up process.

(e) If a RUC Start-Up is terminated in the Real-Time within the applicable RUC Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource is starting up, the RUC Start-Up Cost is prorated by the ratio of the Start-Up Time before termination over the RUC Start-Up Time.

(f) The RUC Start-Up Cost for a RUC Commitment Period is qualified if an actual Start-Up occurs within that RUC Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates that the resource is Off before the time the resource is instructed to be On as specified in its Start-Up Instruction and is On in the Settlement Intervals that fall within the CAISO RUC Commitment Period. The CAISO will determine whether the resource is On for this purpose based on whether its metered Energy is at or above the resource’s Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3.

(g) The RUC Start-Up Cost shall be qualified if an actual Start-Up occurs. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Intervals indicates the unit is Off before the time the resource is instructed to be On as specified in its Start Up Instruction and is On in the Settlement Intervals that fall within the CAISO RUC Commitment Period.

**11.8.3.1.2 RUC Minimum Load Cost**

The RUC Minimum Load Cost for the applicable Settlement Interval shall be the Minimum Load Bid Cost of the Bid Cost Recovery Eligible Resource, divided by the number of Settlement Intervals in a Trading Hour. For each Settlement Interval, only the RUC Minimum Load Cost in a CAISO RUC Commitment Period is eligible for Bid Cost Recovery. The RUC Minimum Load Cost for any Settlement Interval is zero if: (1) the Bid Cost Recovery Eligible Resource is manually pre-dispatched under a Legacy RMR Contract or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule in that Settlement Interval; (2) the Bid Cost Recovery Eligible Resource is not committed or Dispatched in the Real-time Market in the applicable Settlement Interval; or (3) the applicable Settlement Interval is included in an IFM Commitment Period. For the purposes of determining RUC Minimum Load Cost for a Bid Cost Recovery Eligible Resource, recovery of the RUC Minimum Load Cost is subject to the Real-Time Performance Metric as specified in Section 11.8.4.4. For Multi-Stage Generating Resources, the commitment period is further determined based on application of section 11.8.1.3. The RUC Minimum Load Cost calculation will be subject to the Shut-Down State Variable and disqualified as specified in Section 11.17.2.

**11.8.3.1.3 RUC Availability Bid Cost**

The RUC Availability Bid Cost is calculated as the product of the RUC Award with the relevant RUC Availability Bid price, divided by the number of Settlement Intervals in a Trading Hour. The CAISO will determine the RUC Availability Bid Cost based on the MSG Configuration. The RUC Availability Cost for a Bid Cost for an RMR Resource for a Settlement Interval is zero.

**11.8.3.1.4 RUC Transition Cost**

For each Settlement Interval, the RUC Transition Costs shall be based on the MSG Configuration to which the Multi-Stage Generating Resource is transitioning and is allocated to the CAISO commitment period of that MSG Configuration.

**11.8.3.1.4.1 RUC Transition Costs Applicability**

Within any eligible RUC CAISO Commitment Period determined pursuant to the rules specified in Section 11.8.1.3, the CAISO shall apply the RUC Transition Costs for the Settlement Intervals in which the Multi-Stage Generating Resource is actually transitioning from the “from” MSG Configuration and reaches the Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, of the “to” MSG Configuration to which the Multi-Stage Generating Resource is transitioning, subject to the Tolerance Band.

**11.8.3.2 RUC Market Revenues**

For any Settlement Interval, the RUC Market Revenue for a Bid Cost Recovery Eligible Resource is the RUC Availability Payment as specified in Section 11.2.2.1 divided by the number of Settlement Intervals in a Trading Hour. The CAISO will determine the RUC Market Revenues for Multi-Stage Generating Resources based on the Generating Unit level.

**11.8.3.3 RUC Bid Cost Recovery for Metered Subsystem**

**11.8.3.3.1 MSS Elected Gross Settlement**

For an MSS Operator that has elected gross Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the RUC Bid Cost and the RUC Market Revenue are calculated similarly to non-MSS resources on an individual resource basis as described in Sections 11.8.3.1 and 11.8.3.2, respectively.

**11.8.3.3.2 MSS Elected Net Settlement**

For an MSS Operator that has elected net Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the RUC Bid Costs and RUC Market Revenue are combined with RTM Bid Cost and RTM Market Revenue on an MSS level, consistent with the Energy Settlement as calculated according to Section 11.8.4.3.2.

### 11.8.4 RTM Bid Cost Recovery Amount

For purposes of determining the RTM Unrecovered Bid Cost Uplift Payments as determined in Section 11.8.5, and for the purposes of allocation of Net RTM Bid Cost Uplift as described in Section 11.8.6.6 the CAISO shall calculate the RTM Bid Cost Shortfall or the RTM Bid Cost Surplus as the algebraic difference between the RTM Bid Cost and the RTM Market Revenues for each Settlement Interval. The RTM Bid Costs shall be calculated pursuant to Section 11.8.4.1. The RTM Market Revenues shall be calculated pursuant to Section 11.8.4.2. The Energy subject to RTM Bid Cost Recovery is the FMM Instructed Imbalance Energy or RTD Instructed Imbalance Energy described in Section 11.5.1, excluding Standard Ramping Energy, Residual Imbalance Energy, FMM Exceptional Dispatch Energy or RTD Exceptional Dispatch Energy, FMM Derate Energy or RTD Derate Energy, Ramping Energy Deviation, Regulation Energy and MSS Load Following Energy regardless of whether the Energy is from the FMM or RTD, and is subject to the application of the Real-Time Performance Metric as described in Section 11.8.4.4 and the Persistent Deviation Metric described in Section 11.17.

**11.8.4.1 RTM Bid Cost Calculation**

For each Settlement Interval, the CAISO shall calculate RTM Bid Cost for each Bid Cost Recovery Eligible Resource, as the algebraic sum of the RTM Start-Up Cost, RTM Minimum Load Cost, RTM Transition Cost, RTM Pump Shut-Down Cost, RTM Energy Bid Cost, RTM Pumping Cost and RTM AS Bid Cost. For each Settlement Interval, the CAISO shall calculate RTM Bid Cost for each RMR Resource as the algebraic sum of the RTM Start-Up Cost adjusted to remove Opportunity Costs and Variable Start-Up Operations and Maintenance Adders, RTM Transition Costs adjusted to remove Opportunity Costs and Variable Start-Up Operations and Maintenance Adders, RTM Energy Bid Cost adjusted to remove Opportunity Costs and Variable Energy Operations and Maintenance Adders, and RTM AS Bid Cost. For Multi-Stage Generating Resources, in addition to the specific RTM Bid Cost rules described in Section 11.8.4.1, the rules described in Section 11.8.1.3 will be applied to further determine the applicable MSG Configuration-based CAISO Market Start-Up Bid Cost, Transition Bid Cost, and Minimum Load Bid Cost, in a given Settlement Interval. For Multi-Stage Generating Resources, the incremental RTM Start-Up Cost, RTM Minimum Load Cost, and RTM Transition Cost to provide RTM committed Energy or awarded Ancillary Services capacity for an MSG Configuration other than the self-scheduled MSG Configuration are determined by the RTM optimization rules in specified in Section 34.

**11.8.4.1.1 RTM Start-Up Cost**

For each Settlement Interval of the applicable RTM Commitment Period, the RTM Start-Up Cost shall consist of the Start-Up Bid Cost of the Bid Cost Recovery Eligible Resource applicable to the Real-Time Market divided by the number of Settlement Intervals in the applicable RTM Commitment Period. For each Settlement Interval, only the RTM Start-Up Cost in a CAISO RTM Commitment Period is eligible for Bid Cost Recovery. The CAISO will determine the RTM Start-Up Cost for a Multi-Stage Generating Resource based on the MSG Configuration committed by the CAISO in the RTM. The following rules shall be applied in sequence and shall qualify the RTM Start-Up Cost in an RTM Commitment Period:

(a) The RTM Start-Up Cost is zero if there is an RTM Self-Commitment Period within the RTM Commitment Period.

(b) The RTM Start-Up Cost is zero if the Bid Cost Recovery Eligible Resource has been manually pre-dispatched under a Legacy RMR Contract or the resource is flagged as an RMR Dispatch in the Day-Ahead Schedule or Real-Time Market anywhere within that RTM Commitment Period.

(c) The RTM Start-Up Cost is zero if the Bid Cost Recovery Eligible Resource is started within the Real-Time Market Commitment Period pursuant to an Exceptional Dispatch issued in accordance with Section 34.11.2 to: (1) perform Ancillary Services testing; (2) perform pre-commercial operation testing for Generating Units; or (3) perform PMax testing.

(d) The RTM Start-Up Cost is zero if there is no RTM Start-Up at the start of that RTM Commitment Period because the RTM Commitment Period is the continuation of an IFM Commitment Period or RUC Commitment Period from the previous Trading Day.

(e) If an RTM Start-Up is terminated in the Real-Time within the applicable RTM Commitment Period through an Exceptional Dispatch Shut-Down Instruction issued while the Bid Cost Recovery Eligible Resource is starting up, the RTM Start-Up Cost is prorated by the ratio of the Start-Up Time before termination over the Real-Time Market Start-Up Time.

(f) The RTM Start-Up Cost shall be qualified if an actual Start-Up occurs within that RTM Commitment Period. An actual Start-Up is detected when the relevant metered Energy in the applicable Settlement Interval(s) indicates the unit is Off before the time the resource is instructed to be On as specified in its Start-Up Instruction and is On in the Settlement Interval that falls within the CAISO RTM Commitment Period. The CAISO will determine whether the resource is On for this purpose based on whether its metered Energy is at or above the resource’s Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3. The CAISO will determine that the Multi-Stage Generating Resource is On based on the MSG Configuration that the CAISO has committed in the Real-Time Market.

(g) The RTM Start-Up Cost for an RTM Commitment Period shall be qualified if an actual Start-Up occurs earlier than the start of the RTM Market Start-Up, if the relevant Start-Up is still within the same Trading Day and the Bid Cost Recovery Eligible Resource actually stays on until the RTM Start-Up, otherwise the Start-Up Bid Cost is zero for the RTM Commitment Period.

(h) For Short-Start Units, the first Start-Up Bid Costs within a CAISO IFM Commitment Period are qualified IFM Start-Up Costs as described above in Section 11.8.2.1.1(g). For subsequent Start-Ups of Short-Start Units after the CAISO Shuts Down a resource and then the CAISO issues a Start-Up Instruction pursuant to a CAISO RTM Commitment Period within the CAISO IFM Commitment Period, the Start-Up Bid Costs shall be qualified as RTM Start-Up Costs, provided that the resource actually Shut-Down and Started-Up based on CAISO Shut-Down and Start-Up Instructions.

**11.8.4.1.2 RTM Minimum Load Cost**

The RTM Minimum Load Cost is the Minimum Load Bid Cost of the Bid Cost Recovery Eligible Resource applicable for the Real-Time Market, divided by the number of Settlement Intervals in a Trading Hour. For each Settlement Interval, only the RTM Minimum Load Cost in a CAISO RTM Commitment Period is eligible for Bid Cost Recovery. The RTM Minimum Load Cost for any Settlement Interval is zero if: (1) the Settlement Interval is included in a RTM Self-Commitment Period for the Bid Cost Recovery Eligible Resource; (2) the Bid Cost Recovery Eligible Resource has been manually dispatched under a Legacy RMR Contract or the resource has been flagged as an RMR Dispatch in the Day-Ahead Schedule or the Real-Time Market in that Settlement Interval; (3) for all resources that are not Multi-Stage Generating Resources, that Settlement Interval is included in an IFM Commitment Period or RUC Commitment Period; or (4) the Bid Cost Recovery Eligible Resource is committed pursuant to Section 34.11.2 for the purpose of performing Ancillary Services testing, pre-commercial operation testing for Generating Units, or PMax testing. A resource’s RTM Minimum Load Costs for Bid Cost Recovery purposes are subject to the application of the Real-Time Performance Metric as specified in Section 11.8.4.4. For Multi-Stage Generating Resources, the commitment period is further determined based on application of Section 11.8.1.3. For all Bid Cost Recovery Eligible Resources that the CAISO Shuts Down, either through an Exceptional Dispatch or an Economic Dispatch through the Real-Time Market, from its Day-Ahead Schedule that was also from a CAISO commitment, the RTM Minimum Load Costs will include negative Minimum Load Cost Bids for Energy between the Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and zero (0) MWhs.

**11.8.4.1.3 RTM Pump Shut-Down Cost**

The RTM Pump Shut-Down Cost for each Settlement Interval is the relevant Pump Shut-Down Cost submitted by the Scheduling Coordinator only for Pumped-Storage Hydro Units and Participating Load, divided by the number of Settlement Intervals in which such resource was committed by the Real-Time Market in a Trading Hour with scheduled pumping operation and in which an actual Shut-Down occurs and the resource does not actually operate in pumping mode or serve Load in that Settlement Interval (as detected through Meter Data). The RTM Pump Shut-Down Cost for a Real-Time Market Shut-Down event shall be zero if: (1) it is followed by a RTM Self-Commitment Period in generation mode or offline mode; or (2) the Shut-Down is due to an Outage reported through the CAISO’s outage management system as described in Section 9.

**11.8.4.1.4 RTM Pumping Bid Cost**

For Pumped-Storage Hydro Units and Participating Load only, the RTM Pumping Bid Cost for the applicable Settlement Interval shall be the Pumping Cost submitted to the CAISO in the RTM divided by the number of Settlement Intervals in a Trading Hour. The Pumping Cost is negative since it represents the amount the entity is willing to pay to pump or serve Load. The Pumping Cost is included in RTM Bid Cost computation for a Pumped-Storage Hydro Unit and Participating Load committed by the Real-Time Market to pump or serve Load, if it actually operates in pumping mode or serves Load in that Settlement Interval. The RTM Energy Bid Cost for a Participating Load for any Settlement Interval is set to zero for any Energy consumed in excess of instructed Energy. The RTM Pumping Bid Cost for any Settlement Interval is zero if: (1) the Settlement Interval is included in a RTM Self-Commitment Period for the Bid Cost Recovery Eligible Resource; (2) the Bid Cost Recovery Eligible Resource has been manually dispatched under an RMR Contract or the resource has been flagged as an RMR Dispatch in the Day- Ahead Schedule or the Real-Time Market in that Settlement Interval; (3) the Bid Cost Recovery Eligible Resource is not actually in pumping mode in that Settlement Interval; (4) that Settlement Interval is included in an IFM or RUC Commitment Period; or (5) the Bid Cost Recovery Eligible Resource is committed pursuant to Section 34.11.2 for the purpose of performing Ancillary Services testing or pre-commercial operation testing.

**11.8.4.1.5 RTM Energy Bid Cost**

For any Settlement Interval, the RTM Energy Bid Cost for the Bid Cost Recovery Eligible Resource except Participating Loads shall be computed as the sum of the products of each RTD Instructed Imbalance Energy portion, except Standard Ramping Energy, Residual Imbalance Energy, FMM Exceptional Dispatch Energy or RTD Exceptional Dispatch Energy, FMM Derate Energy or RTD Derate Energy, MSS Load Following Energy, Ramping Energy Deviation and Regulating Energy, with the relevant Energy Bid prices, the Default Energy Bid price, or the Locational Marginal Price, if any, as further described in Section 11.17, for each Dispatch Interval in the Settlement Interval. For Settlement Intervals for which the Bid Cost Recovery Eligible Resource is ramping up to or down from a rerated Minimum Load that was increased pursuant to Section 9.3.3 for the Real-Time Market, the RTM Energy incurred by the ramping will be classified as FMM Derate Energy or RTD Derate Energy and will not be included in Bid Cost Recovery. For a Bid Cost Recovery Eligible Resource that is ramping up to or down from an Exceptional Dispatch, the relevant Energy Bid Cost related to the Energy caused by ramping will be settled on the same basis as the Energy Bid used in the Settlement of the Exceptional Dispatch that led to the ramping. The RTM Energy Bid Cost for a Bid Cost Recovery Eligible Resource, including Participating Loads and Proxy Demand Response Resources, for a Settlement Interval is subject to the Real-Time Performance Metric as described in Section 11.8.4.4 and the Persistent Deviation Metric as described in Section 11.17. Any Uninstructed Imbalance Energy in excess of FMM Instructed Imbalance Energy and RTD Instructed Imbalance Energy is also not eligible for Bid Cost Recovery. For a Multi-Stage Generating Resource the CAISO will determine the RTM Energy Bid Cost based on the Generating Unit level. For RMR Resources, the CAISO will determine the RTM Energy Bid Cost based on the relevant Energy Bid adjusted to remove Opportunity Costs.

**11.8.4.1.6 RTM AS Bid Cost**

For each Settlement Interval, the Real-Time Market AS Bid Cost shall be the product of the average Real-Time Market AS Award from each accepted AS Bid submitted in the Settlement Interval for the Real-Time Market, reduced by any relevant tier-1 No Pay capacity in that Settlement Interval (but not below zero), with the relevant AS Bid price. The average Real-Time Market AS Award for a given AS in a Settlement Interval is the sum of the 15-minute Real-Time Market AS Awards in that Settlement Interval, each divided by the number of 15-minute Commitment Intervals in a Trading Hour and prorated to the duration of the Settlement Interval (10/15 if the Real-Time Market AS Award spans the entire Settlement Interval, or 5/15 if the Real-Time Market AS Award spans half the Settlement Interval). For a Multi-Stage Generating Resource the CAISO will determine the RTM AS Bid Cost based on the Generating Unit level. The Real-Time Market AS Bid Cost shall also include Mileage Bid Costs. For each Settlement Interval, the Real-Time Mileage Bid Cost shall be the product of Instructed Mileage associated with a Real-Time Regulation capacity award, as adjusted for accuracy consistent with Section 11.10.1.7, and the relevant Mileage Bid price divided by the number of Settlement Intervals for the Real-Time Market in a Trading Hour. The CAISO will determine and calculate the Real Time Market Mileage Bid Cost for a Multi-Stage Generating Resource at the Generating Unit level. For an RMR Resource, the RTM AS Bid Cost shall be zero.

**11.8.4.1.7 RTM Transition Cost**

For each Settlement Interval, the RTM Transition Costs shall be based on the MSG Configuration to which the Multi-Stage Generating Resource is transitioning and are allocated to the CAISO commitment period of that MSG Configuration.

**11.8.4.1.7.1 RTM Transition Cost Applicability**

Within any eligible RTM CAISO Commitment Period determined pursuant to the rules specified in Section 11.8.1.3, the CAISO shall apply the RTM Transition Costs for the Settlement Intervals in which the Multi-Stage Generating Resource is actually transitioning from the “from” MSG Configuration and reaches the Minimum Load as registered in the Master File, or if applicable, as modified pursuant to Section 9.3.3, of the “to” MSG Configuration to which the Multi-Stage Generating Resource is transitioning, subject to the Tolerance Band.

**11.8.4.2 RTM Market Revenue Calculations**

**11.8.4.2.1** For each Settlement Interval in a CAISO Real-Time Market Commitment Period, the RTM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of the elements listed below in this Section. For Multi-Stage Generating Resources the RTM Market Revenue calculations will be made at the Generating Unit level.

(a) The sum of the products of the FMM or RTD Instructed Imbalance Energy (including Minimum Load Energy of the Bid Cost Recovery Eligible Resource committed in RUC and where for Pumped-Storage Hydro Units and Participating Load operating in the pumping mode or serving Load, the MWh is negative), except Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, Derate Energy, MSS Load following Energy, Ramping Energy Deviation and Regulation Energy, with the relevant FMM and RTD LMP, for each Dispatch Interval in the Settlement Interval. These amounts are subject to the Real-Time Performance Metric and the Persistent Deviation Metric as described in Sections 11.8.4.4 and 11.17, respectively.

(b) The product of the Real-Time Market AS Award from each accepted Real-Time Market AS Bid in the Settlement Interval with the relevant ASMP, divided by the number of fifteen (15)-minute Commitment Intervals in a Trading Hour (4), and prorated to the duration of the Settlement Interval.

(c) The relevant tier-1 No Pay charges for that Bid Cost Recovery Eligible Resource in that Settlement Interval.

(d) The Forecasted Movement and Uncertainty Awards Settlement Amounts as calculated pursuant to Section 11.25 are included in the RTM Market Revenues calculation, not including:

(1) the amounts rescinded pursuant to Section 11.25.3;

(2) Forecasted Movement revenue when there are changes in Self-Schedules across consecutive Trading Hours; and

(3) Forecasted Movement revenue when there are changes in EIM Base Schedules across consecutive Trading Hours without Economic Bids.

**11.8.4.2.2** For each Settlement Interval in a non-CAISO Real-Time Market Commitment Period, the Real-Time Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of the following:

(a) The sum of the products of the FMM or RTD Instructed Imbalance Energy (excluding the Minimum Load Energy of Bid Cost Recovery Eligible Resources committed in RUC), except, Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, Derate Energy, MSS Load Following Energy, Ramping Energy Deviation and Regulating Energy, with the relevant FMM or RTD Market LMP, for each Dispatch Interval in the Settlement Interval. These amounts are subject to the Real-Time Performance Metric and the Persistent Deviation Metric as described in Sections 11.8.4.4 and 11.17, respectively.

(b) The product of the Real-Time Market AS Award from each accepted Real-Time Market AS Bid in the Settlement Interval with the relevant ASMP, divided by the number of fifteen (15)-minute Commitment Intervals in a Trading Hour (4), and prorated to the duration of the Settlement Interval.

(c) The relevant tier-1 No Pay charges for that Bid Cost Recovery Eligible Resource in that Settlement Interval.

(d) The Forecasted Movement and Uncertainty Awards Settlement Amounts as calculated pursuant to Section 11.25 are included in the RTM Market Revenues calculation, not including:

(1) the amounts rescinded pursuant to Section 11.25.3;

(2) Forecasted Movement revenue when there are changes in Self-Schedules across consecutive Trading Hours; and

(3) Forecasted Movement revenue when there are changes in EIM Base Schedules across consecutive Trading Hours without Economic Bids.

**11.8.4.3 RTM Bid Cost Recovery for Metered Subsystems**

In addition to the exclusions to actual Energy delivered as provided in Section 11.8.4, for MSS resources, the Energy subject to RTM Bid Cost Recovery also excludes Minimum Load Energy if the resource is not committed by the CAISO in the Real-Time. As provided below, the RTM Bid Cost Recovery for MSS Operators differs based on whether the MSS Operator has elected gross or net Settlement; except that the calculation of the RTM Bid Costs and RTM Market Revenues for Ancillary Services will be as provided in Sections 11.8.4.1.6 and 11.8.4.2 and does not vary on the basis of the MSS’s election of gross or net Settlement.

**11.8.4.3.1 MSS Elected Gross Settlement**

For an MSS Operator that has elected gross Settlement, regardless of other MSS optional elections (Load following or RUC opt-in or out), the RTM Bid Cost and RTM Market Revenue of the RTD Instructed Imbalance Energy subject to Bid Cost Recovery is determined for each resource in the same way these amounts are determined for a non-MSS resource pursuant to the rules specified in Section 11.8.4. The RTM Bid Cost Shortfall or Surplus for Energy and Ancillary Services in total is determined for each Trading Hour of the RTM over the Trading Day by taking the algebraic difference between the RTM Bid Cost and RTM Market Revenue.

**11.8.4.3.2 MSS Elected Net Settlement**

For MSS entities that have elected net Settlement regardless of other MSS optional elections (i.e., Load following or not, or RUC opt-in or out), unlike non-MSS resources, the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus is treated at the MSS level and not at the resource specific level, and is calculated as the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus of all BCR Eligible Resources within the MSS. In calculating the Energy RTM Market Revenue for all the resources within the MSS as provided in Section 11.8.4.2, the CAISO will use the FMM MSS Price or the RTD MSS Price, as applicable. The RUC Bid Cost Shortfall, RUC Bid Cost Surplus, RTM Bid Cost Shortfall, and RTM Bid Cost Surplus for Energy, RUC Availability and Ancillary Services are first calculated separately for the MSS for each Settlement Interval of the Trading Day, with qualified Start-Up Bid Costs, qualified Minimum Load Bid Costs and qualified Multi-Stage Generator Transition Bid Costs included into the RUC Bid Cost Shortfalls, RUC Bid Cost Surpluses, RTM Bid Cost Shortfalls, and RTM Bid Cost Surpluses of Energy calculation. The MSS’s overall RUC Bid Cost Shortfall or RUC Bid Cost Surplus, and RTM Bid Cost Shortfall or RTM Bid Cost Surplus is then calculated as the algebraic sum of the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus for Energy and the RUC Bid Cost Shortfall or RUC Bid Cost Surplus and RTM Bid Cost Shortfall or RTM Bid Cost Surplus for Ancillary Services for each Settlement Interval.

**11.8.4.4 Application of the Real-Time Performance Metric**

The CAISO will adjust the RTM Energy Bid Cost, the RTM Market Revenues, and RTM Minimum Load Costs, the IFM Minimum Load Cost and IFM Energy Bid Cost calculations, and the IFM Market Revenues determined pursuant to Sections 11.8.4.1.5, 11.8.4.2, 11.8.4.1.2, 11.8.2.1.2, 11.8.2.1.5 and 11.8.2.2, respectively, by multiplying the Real-Time Performance Metric with those amounts for the applicable Settlement Interval, pursuant to the rules specified in this Section 11.8.4.4 and its subsections. The CAISO will apply the Real-time Performance Metric to the IFM Pumping Bid Costs and RTM Pumping Bid Costs in the same manner in which the CAISO applies the Real-time Performance Metric to the RTM Energy Bid Costs as specified in this Section 11.8.4.4, and its subsections.

**11.8.4.4.1** If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs and the RTM Market Revenues are greater than or equal to zero (0), the CAISO will apply the Real-Time Performance Metric to RTM Energy Bid Costs, RUC Minimum Load Costs and RTM Minimum Load Costs, and not the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2(c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs and the IFM Market Revenues are greater than or equal to zero (0), the CAISO will apply the Real-Time Performance Metric instead of Day-Ahead Metered Energy Adjustment Factor to the IFM Minimum Load Costs and IFM Energy Bid Costs, and not the IFM Market Revenues.

**11.8.4.4.2** If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs are greater than or equal to zero (0) and the RTM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric to the RTM Energy Bid Costs, RUC Minimum Load Costs and RTM Minimum Load Costs and the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2(c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs are greater than or equal to zero (0) and the IFM Market Revenues are negative the CAISO will apply the Real-Time Performance Metric instead of the Day-ahead Metered Energy Adjustment Factor to the IFM Minimum Load Costs and IFM Energy Bid Costs, and IFM Market Revenues.

**11.8.4.4.3** If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs are negative and the RTM Market Revenues are greater than or equal to zero (0), the CAISO will not apply Real-Time Performance Metric to the RTM Energy Bid Costs, RUC Minimum Load Costs and RTM Minimum Load Costs or the RTM Market Revenues. In addition, for the cases described in Sections 11.8.2.1.2(c) and (d), if the sum of IFM Energy Bid Costs and the IFM Minimum Load Costs is negative and the IFM Market Revenue is greater than or equal to zero (0), the CAISO will not apply the Real-Time Performance Metric to the IFM Minimum Load Costs, IFM Energy Bid Costs or the IFM Market Revenues.

**11.8.4.4.4** If the RTM Energy Bid Costs plus the RUC Minimum Load Costs and RTM Minimum Load Costs, and the RTM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric to the RTM Market Revenues but not the RTM Energy Bid Costs or the RUC Minimum Load Costs and RTM Minimum Load Costs. In addition, for the cases described in Sections 11.8.2.1.2(c) and (d), if the IFM Energy Bid Costs plus the IFM Minimum Load Costs and the IFM Market Revenues are negative, the CAISO will apply the Real-Time Performance Metric instead of the Day-Ahead Metered Energy Adjustment Factor to the IFM Market Revenues but not the IFM Minimum Load Costs and IFM Energy Bid Costs.

**11.8.4.4.5** If for a given Settlement Interval the absolute value of the resource’s Metered Energy, less Regulation Energy and less Expected Energy, is less than or equal to the Performance Metric Tolerance Band, then the CAISO will not apply the Real-Time Performance Metric to the calculation of the RTM Energy Bid Cost, RUC Minimum Load Cost and RTM Minimum Load Cost, or RTM Market Revenue.

### 11.8.5 Unrecovered Bid Cost Uplift Payment

Bid Cost Recovery Eligible Resources will receive an Unrecovered Bid Cost Uplift Payment as described in this Section below. For Multi-Stage Generating Resources, Unrecovered Bid Cost Uplift Payments will be calculated and made at the Generating Unit level and not the MSG Configuration level. MSS Bid Cost Recovery Eligible Resources by MSS Operators that have elected net settlement will receive Unrecovered Bid Cost Uplift Payment for MSS Bid Cost Recovery Eligible Resources at the MSS level and not by individual resource. MSS Bid Cost Recovery Eligible Resources by MSS Operators that have elected gross settlement will receive Unrecovered Bid Cost Uplift Payments at the MSS Bid Cost Recovery Eligible Resource level like all other resources.

**11.8.5.1 IFM Unrecovered Bid Cost Uplift Payment**

Scheduling Coordinators shall receive an IFM Unrecovered Bid Cost Uplift Payment for a Bid Cost Recovery Eligible Resource, if the net of all IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses calculated pursuant to Section 11.8.2 over a Trading Day is positive.

**11.8.5.2 RUC and RTM Unrecovered Bid Cost Uplift Payment**

Scheduling Coordinators shall receive RUC and RTM Unrecovered Bid Cost Uplift Payments for a Bid Cost Recovery Eligible Resource, if the net of all RUC Bid Cost Shortfalls and RUC Bid Cost Surpluses calculated pursuant to Section 11.8.3, and the RTM Bid Cost Shortfalls and RTM Bid Cost Surpluses calculated pursuant to Section 11.8.4, for that Bid Cost Recovery Eligible Resource over a Trading Day is positive. For Metered Subsystems that have elected net settlement, the Unrecovered Bid Cost Uplift Payment will be the sum, if positive, of the RUC, and RTM Bid Cost Shortfall or RUC, and RTM Bid Cost Surplus for each Trading Hour over the Trading Day for all Bid Cost Recovery Eligible Resources in the MSS.

### 11.8.6 System-Wide IFM, RUC and RTM Bid Cost Uplift Allocation

**11.8.6.1 Determination of IFM, RUC and RTM Bid Cost Uplift**

For each Settlement Interval, the CAISO shall determine the IFM, RUC and RTM Bid Cost Uplift for purposes of allocating the IFM, RUC and RTM Bid Cost Uplift as described below. In determining the IFM, RUC and RTM Bid Cost Uplifts below, the Unrecovered Bid Cost Uplift Payments for MSS BCR Eligible Resources in Metered Subsystems where the MSS Operator has elected net Settlement will be included on an MSS basis and not on an individual resource basis.

(i) The IFM Bid Cost Uplift shall be the net of the IFM Bid Cost Shortfalls and IFM Bid Cost Surpluses for a Settlement Interval of all Bid Cost Recovery Eligible Resources with Unrecovered Bid Cost Uplift Payments.

(ii) The RUC Bid Cost Uplift shall be the net of the RUC Bid Cost Shortfalls and RUC Bid Cost Surpluses for a Settlement Interval of all Bid Cost Recovery Eligible Resources in the CAISO Balancing Authority Area with Unrecovered Bid Cost Uplift Payments.

(iii) The RTM Bid Cost Uplift shall be the net of the RTM Bid Cost Shortfalls and RTM Bid Cost Surpluses for a Settlement Interval of all Bid Cost Recovery Eligible Resources with Unrecovered Bid Cost Uplift Payments.

**11.8.6.2 Sequential Netting of RUC and RTM Bid Cost Uplift**

For each Settlement Interval, the Net RUC or Real-Time Market Bid Cost Uplift is determined for the purposes of allocating Net RUC or Real-Time Market Bid Cost Uplift by the following netting rules applied:

(i) The Net RUC Bid Cost Uplift is equal to the greater of zero or any positive RUC Bid Cost Uplift offset by negative Real-Time Market Bid Cost Uplift.

(ii) The Net Real-Time Market Bid Cost Uplift is equal to the greater of zero or any positive Real-Time Market Bid Cost Uplift offset by any negative RUC Bid Cost Uplift.

**11.8.6.3 Determination of Total Positive CAISO Markets Uplifts**

**11.8.6.3.1 Total Positive IFM Uplifts**

Any positive Net IFM Bid Cost Uplifts are reduced by scaling them with the uplift ratio in Section 11.8.6.3.1(iii) to determine the Total IFM Uplift (for a Settlement Interval) as follows:

(i) The Total IFM Uplift is the Net IFM Bid Cost Uplift for all Settlement Intervals in the IFM Market.

(ii) The Total Positive IFM Uplift is determined as the sum of the positive IFM Bid Cost Uplift for all Settlement Intervals in the IFM Market.

(iii) The uplift ratio is equal to the Total IFM Uplift divided by the Total Positive IFM Uplift.

**11.8.6.3.2 Net RUC Bid Cost Uplift and RTM Bid Cost Uplift**

The CAISO will determine the Net RUC Bid Cost Uplift and the Net RTM Bid Cost Uplift to be allocated to each Balancing Authority Area in the EIM Area as follows:

(i) For each Balancing Authority Area separately, the CAISO will calculate a combined RUC Bid Cost Uplift and RTM Bid Cost Uplift amount based on the RUC Bid Cost Shortfall, RUC Bid Cost Surplus, RTM Bid Cost Shortfall, and RTM Bid Cost Surplus of each supply resource located within the Balancing Authority Area for each Settlement Interval.

(ii) For each Balancing Authority Area separately, for each Trading Day, the CAISO will calculate a daily combined total RUC Bid Cost Uplift and RTM Bid Cost Uplift amount as the sum of all the Settlement Interval values calculated according to Section 11.8.6.3.2(i).

(iii) For each Balancing Authority Area separately, for each Trading Day, the CAISO will calculate a combined total positive RUC Bid Cost Uplift and RTM Bid Cost Uplift amount as the sum of the positive Settlement Interval values calculated according to Section 11.8.6.3.2(i).

(iv) The CAISO will calculate the daily uplift ratio for the RUC and RTM, for each Balancing Authority Area in the EIM Area, as the daily combined total RUC Bid Cost Uplift and RTM Bid Cost Uplift amount, calculated according to Section 11.8.6.2(ii), divided by the daily combined total positive RUC Bid Cost Uplift and RTM Bid Cost Uplift, calculated according to Section 11.8.6.2(iii).

(v) For each Settlement Interval and each Balancing Authority Area in the EIM Area, the CAISO will multiply the applicable daily uplift ratio with each combined total positive RUC Bid Cost Uplift and each combined total RTM Bid Cost Uplift to determine the Net RUC Bid Cost Uplift and the preliminary Net RTM Bid Cost Uplift, respectively, for each Balancing Authority Area.

(vi) The CAISO shall adjust the preliminary Net RTM Bid Cost Uplift amounts calculated in Section 11.8.6.3.2(v) by –

(a) dividing the sum of net EIM Transfers out of a Balancing Authority Area by that Balancing Authority Area’s EIM Measured Demand, and the net EIM Transfer out of the Balancing Authority Area;

(b) multiplying the preliminary Net RTM Bid Cost Uplift amounts by the ratio calculated in Section 11.8.6.3.2(vi)(a); and

(c) reducing the preliminary Net RTM Bid Cost Uplift amounts of the EIM Entity Balancing Authority Area with the net transfer out by the amount calculated in Section 11.8.6.3.2(vi)(b) and adding that amount to the EIM Entity Balancing Authority Area with the net transfer in to determine the final preliminary Net RTM Bid Cost Uplift amounts.

(vii) For each Settlement Interval, the Net RUC Bid Cost Uplift and final Net RTM Bid Cost Uplift apportionment by Settlement Interval for each Balancing Authority Area in the EIM Area will be the sum of the amounts calculated in Sections 11.8.6.3.2(v) and, for Net RTM Bid Cost Uplift only, 11.8.6.3.2(vi) for each Balancing Authority Area in the EIM Area.

**11.8.6.4 Allocation of IFM Bid Cost Uplift**

For each Trading Hour of the IFM the hourly IFM Bid Cost Uplift is allocated as follows:

**11.8.6.4.1 Allocation in the First Tier**

The hourly IFM Bid Cost Uplift is allocated in the first tier as follows:

(i) The hourly amount of IFM Bid Cost Uplift allocated to each Scheduling Coordinator is equal to the product of the IFM Bid Cost Uplift rate and the IFM uplift obligation for the Scheduling Coordinator.

(ii) The IFM Bid Cost Uplift rate is equal to the IFM Bid Cost Uplift divided by the sum of the positive IFM Load Uplift Obligations for all Scheduling Coordinators and the IFM system-wide Virtual Demand Award uplift obligation, subject to the condition that the IFM Bid Cost Uplift rate cannot exceed the ratio of the hourly IFM Bid Cost Uplift for the Trading Hour divided by the maximum of (a) the sum of all hourly IFM Load Uplift Obligations for all Scheduling Coordinators in that Trading Hour or (b) the sum of all hourly Generation scheduled in the Day-Ahead Schedule and IFM upward AS Awards for all Scheduling Coordinators from CAISO-committed Bid Cost Recovery Eligible Resources in that Trading Hour.

(iii) The IFM uplift obligation for each Scheduling Coordinator is equal to the sum of the IFM Load Uplift Obligation for the Scheduling Coordinator and any IFM Virtual Demand Award uplift obligation for the Scheduling Coordinator.

(iv) The IFM Load Uplift Obligation for each Scheduling Coordinator, including Scheduling Coordinators for Metered Subsystems regardless of their MSS optional elections (net/gross Settlement, Load following, RUC opt-in/out), is equal to the positive difference between the total Demand scheduled in the Day-Ahead Schedule of that Scheduling Coordinator and the sum of scheduled Generation and scheduled imports from the Self-Schedules in the Day-Ahead Schedule of that Scheduling Coordinator, adjusted by any applicable Inter-SC Trades of IFM Load Uplift Obligations.

(v) The IFM system-wide Virtual Demand Award uplift obligation is calculated for each hour in the IFM and is equal to maximum of zero (0) or the following quantity: the total system-wide Virtual Demand Awards from the IFM minus the total system-wide Virtual Supply Awards from the IFM, plus the minimum of zero (0) or the following quantity: the total amount of Scheduled Demand (which excludes Virtual Demand Awards), minus Measured Demand.

(vi) For each Scheduling Coordinator with positive net Virtual Demand Awards, the IFM Virtual Demand Award uplift obligation is equal to the product of (a) the positive net Virtual Demand Awards for the Scheduling Coordinator divided by the sum of each Scheduling Coordinator’s positive net Virtual Demand Award and (b) the IFM system-wide Virtual Demand Award uplift obligation. For each Scheduling Coordinator with negative net Virtual Demand Awards, the IFM Virtual Demand Award uplift obligation is zero (0).

**11.8.6.4.2 Allocation in the Second Tier**

In the second tier, Scheduling Coordinators, including Scheduling Coordinators for MSS Operators that have elected both to not follow their Load and gross Settlement, will be charged for an amount equal to any remaining hourly IFM Bid Cost Uplift for the Trading Hour in proportion to the Scheduling Coordinator’s Measured Demand. Scheduling Coordinators for MSS Operators that have elected to either follow their Load or net Settlement, or both, will be charged for an amount equal to any remaining hourly IFM Bid Cost Uplift for the Trading Hour in proportion to their MSS Aggregation Net Measured Demand.

**11.8.6.5 Allocation of RUC Compensation Costs**

**11.8.6.5.1 Calculation of RUC Compensation Costs**

For each Trading Hour of the RUC, the CAISO shall calculate the RUC Compensation Costs separately for RCU and RCD as the sum of the RUC Availability Payments for either RCU or RCD. The RUC Compensation Costs for RCU additionally includes the hourly Net RUC Bid Cost Uplift.

**11.8.6.5.2 Calculation of the Hourly Net RUC Bid Cost Uplift**

For each Trading Hour of the RUC, the hourly Net RUC Bid Cost Uplift is determined as the sum over the Settlement Intervals in that Trading Hour of the product of any positive Net RUC Bid Cost Uplift remaining in the Settlement Interval after the sequential netting in Section 11.8.6.2 and the application of the uplift ratio as determined in Section 11.8.6.3. Scheduling Coordinators for MSS Operators that are non-Load following and under gross Settlement receive the allocation of hourly Net RUC Bid Cost Uplift like all other Scheduling Coordinators.

**11.8.6.5.3 Allocation of the RUC Compensation Costs**

The CAISO allocates the sum of the RUC Compensation Costs as specified below.A Scheduling Coordinator’s allocation of RCU costs in tier 1 is the product of the RCU tier 1 cost allocation quantity, as specified in Section 11.8.6.5.3.1, and the RCU tier 1 cost allocation price, as specified in Section 11.8.6.5.3.3.

A Scheduling Coordinator’s allocation of RCD costs in tier 1 is the product of the RCD tier 1 cost allocation quantity, as specified in Section 11.8.6.5.3.2, and the RCD tier 1 cost allocation price, as specified in 11.8.6.5.3.4.

The CAISO allocates the costs of Reliability Capacity procurement not recovered through the RCU or RCD tier 1 cost allocations to Scheduling Coordinators in proportion to their Metered Demand in the Trading Hour for which the CAISO procured the Imbalance Reserves.

**11.8.6.5.3.1 RCU Tier 1 Cost Allocation Quantity**

A Scheduling Coordinator’s total RCU tier 1 cost allocation quantity is the sum of the tier 1 quantities, specified as follows.

For a Scheduling Coordinator with net Virtual Supply Awards in a Trading Hour, the RCU tier 1 cost allocation quantity associated with its Virtual Supply is the higher of: (a) zero; or (b) the Scheduling Coordinator’s net Virtual Awards, if the Balancing Authority Area in which that Scheduling Coordinator is located has net Virtual Supply.

For a Scheduling Coordinator with under-scheduled Load in a Trading Hour, the RCU tier 1 cost allocation quantity associated with its under-scheduled load is the net negative metered demand, excluding net negative demand associated with balanced ETC/TOR rights and negative deviation for Participating Load resulting from a market dispatch.

**11.8.6.5.3.2 RCD Tier 1 Cost Allocation Quantity**

A Scheduling Coordinator’s total RCD tier 1 cost allocation quantity is the sum of the tier 1 quantities, specified as follows.

For a Scheduling Coordinator with net Virtual Demand Awards in a Trading Hour, the RCD tier 1 cost allocation quantity associated with its Virtual Demand is the lower of: (a) zero; or (b) the Scheduling Coordinator’s net Virtual Awards, if the Balancing Authority Area in which that Scheduling Coordinator is located has net Virtual Demand.

For a Scheduling Coordinator with over-scheduled Load in a Trading Hour, the RCD tier 1 cost allocation associated with its over-scheduled load is the net positive metered demand, excluding net positive demand associated with balanced ETC/TOR rights and positive deviation for Participating Load resulting from a market dispatch.

**11.8.6.5.3.3 RCU Tier 1 Cost Allocation Price**

The RCU tier 1 cost allocation price for a Trading Hour is the lower of: (a) the RUC Compensation Costs for RCU, as adjusted by payment rescissions applied per Section 11.2.2.2, divided by the total MWs of RCU awards; and (b) the RUC Compensation Costs for RCU to meet Measured Demand divided by the sum of each Scheduling Coordinator’s RCU tier 1 cost allocation quantity in that Trading Hour.

**11.8.6.5.3.4 RCD Tier 1 Cost Allocation Price**

The RCD tier 1 cost allocation price for a Trading Hour is the lower of: (a) the RUC Compensation Costs for RCD, as adjusted by payment rescissions applied per Section 11.2.2.2, divided by the total MWs of RCD awards; and (b) the RUC Compensation Costs for RCD to meet Measured Demand divided by the sum of each Scheduling Coordinator’s RCD tier 1 cost allocation quantity in that Trading Hour

**11.8.6.5.3.5 Reliability Capacity Cost Allocation to MSSs**

The CAISO allocates costs of Reliability Capacity to a MSS the same as any other Scheduling Coordinator irrespective of the MSS’s election, per Section 4.9.13, of net Settlements or gross Settlements.

The CAISO does not allocate costs of Reliability Capacity from either tier 1 or tier 2 to a MSS that has elected, per Section 4.9.13, to Load follow with its generating resources.

**11.8.6.5.3.6 Reliability Capacity Cost Allocation to Holders of ETCs or TORs**

The CAISO excludes from tier 1 and tier 2 allocations for both RCU and RCD the valid and balanced portion of ETC and TOR self-schedules. The CAISO does not exclude from the Reliability Capacity cost allocations any quantities above the valid and balanced portion of ETC or TOR self-schedules.

**11.8.6.6 Allocation of Net RTM Bid Cost Uplift**

(i) For the CAISO Balancing Authority Area, the CAISO will determine the hourly Net RTM Bid Cost Uplift as the sum over all of the Settlement Intervals of the Trading Hour of any positive Net RTM Bid Cost Uplift determined in Section 11.8.6.3.2. The hourly RTM Bid Cost Uplift in the CAISO Balancing Authority Area is allocated to Scheduling Coordinators, including Scheduling Coordinators for MSS Operators that have elected (a) not to follow their Load, and (b) gross Settlement, in proportion to their Measured Demand plus any FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market for the Trading Hour. For Scheduling Coordinators for MSS Operators that have elected (a) not to follow their Load, and (b) net Settlement, the hourly RTM Bid Cost Uplift is allocated in proportion to their MSS Aggregation Net Measured Demand plus any FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market. For Scheduling Coordinators of MSS Operators that have elected to follow their Load, the RTM Bid Cost Uplift shall be allocated in proportion to their MSS Net Negative Uninstructed Deviation plus any FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market. Accordingly, each Scheduling Coordinator shall be charged an amount equal to its Measured Demand plus any FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market times the RTM Bid Cost Uplift rate, where the RTM Bid Cost Uplift rate is computed as the Net RTM Bid Cost Uplift amount divided by the sum of Measured Demand plus any FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self- Schedules in the Day-Ahead Market across all Scheduling Coordinators for the Trading Hour. Any real-time reductions after HASP results are published to HASP Block Intertie Schedules in response to Dispatch Instructions or real-time scheduling curtailments are not allocated any Net RTM Bid Cost Uplift.

(ii) For EIM Entity Balancing Authority Areas, the CAISO will allocate the amounts determined according to Section 11.8.6.3.2 to the applicable EIM Entity Scheduling Coordinator.

\* \* \*

## 11.16 Additional AS and RUC Payment Rescission Requirements

The following provisions apply to the Settlement of rescission of payments for Ancillary Services and RUC Capacity in addition to the provisions of Sections 8.10.8 and 11.10.9 for Ancillary Services and Sections 31.5.7 and 11.2.2.2 for RUC Capacity.

### 11.16.1 Resources with More Than One Capacity Obligation

If the Generating Unit, Participating Load, Proxy Demand Resource, System Unit or System Resource is scheduled to provide more than one capacity obligation in a Settlement Interval, the order in which the non-compliant Ancillary Service and RUC Capacity will be apportioned to the various services under Section 8.10.8 is as follows. For Undispatchable Capacity the non-compliant capacity is first apportioned to RUC Capacity and then to any Non-Spinning Reserves. If the amount of Undispatchable Capacity exceeds the amount of Non-Spinning Reserves, then the payment shall be eliminated for Spinning Reserves. For Unavailable Capacity or Undelivered Capacity the non-compliant capacity is first apportioned to any Non-Spinning Reserves. If the amount of non-compliant Ancillary Service capacity exceeds the amount of Non-Spinning Reserves, then the payment shall be eliminated for Spinning Reserves. If the same Ancillary Service is scheduled in the Day-Ahead Market or Real-Time Market, then the payments shall be rescinded in proportion to the amount of each Ancillary Service scheduled in each market. If the same Ancillary Service is self-provided and Bid, the order of rescission will be first the amount of Ancillary Service amounts submitted in Bids and then the Self-Provided Ancillary Service.

### 11.16.2 Load-Following MSSs with an AS or RUC Capacity Obligation

If a Load following MSS Operator is scheduled to provide Ancillary Service capacity, RUC Capacity, or some combination thereof in a Settlement Interval and if the scheduled capacity or a portion thereof is unavailable for some reason during the Settlement Interval, the non-compliant Ancillary Services and RUC Capacity (i.e., Undispatchable, Unavailable, or Undelivered Capacity) will be not be apportioned to the capacity designated by the MSS Operator as Load following up capacity and Load following down capacity. In determining which of the MSS Operator’s capacity obligations were not available in Real-Time, the capacity designated by the MSS Operator as Load following up capacity and Load following down capacity shall be preserved or take precedence over the other capacity obligations.

\* \* \*

## 11.22 Grid Management Charge

### 11.22.1 CAISO’s Obligation

**11.22.1.1 FERC’s Uniform System of Accounts**

The CAISO shall maintain a set of financial statements and records in accordance with the FERC’s Uniform System of Accounts.

**11.22.1.2 [Not Used]**

### 11.22.2 Costs Recovered Through the Grid Management Charge

The Grid Management Charge shall recover the following costs incurred by the CAISO, as described in more detail in Appendix F, Schedule 1:

 (1) CAISO Operating Costs;

 (2) CAISO Other Costs and Revenues;

 (3) CAISO Financing Costs; and

 (4) CAISO Operating Cost Reserve adjustment; and

 (5) CAISO Cash-Funded Capital and Project Costs.

**11.22.2.1 [Not Used]**

**11.22.2.2 [Not Used]**

**11.22.2.3 [Not Used]**

**11.22.2.4 [Not Used]**

**11.22.2.5 Allocation of the GMC Among Scheduling Coordinators**

The costs recovered through the Grid Management Charge shall be allocated to the service charges that comprise the Grid Management Charge. The costs recovered through the Grid Management Charge shall not exceed $202 million unless the CAISO submits a tariff amendment increasing this amount pursuant to Section 205 of the FPA and FERC accepts such amendment. The service charges, as described in more detail in Appendix F, Schedule 1, Part A, are as follows:

 (a) Market Services Charge;

 (b) System Operations Charge; and

 (c) CRR Services Charge.

The charges shall be levied separately monthly in arrears on all Scheduling Coordinators based on the billing determinants specified below for each charge in accordance with formulae set out in Appendix F, Schedule 1, Part A.

**11.22.2.5.1 Market Services Charge**

Subject to Section 11.22.4, the Market Services Charge for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A.

**11.22.2.5.2 System Operations Charge**

Subject to Section 11.22.4 and the exemption for certain long term contracts set forth in Appendix F, Schedule 1, Part E, the System Operations Charge for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A.

**11.22.2.5.3 CRR Services Charge**

The CRR Services Charge for each Scheduling Coordinator is calculated according to the formula in Appendix F, Schedule 1, Part A.

**11.22.2.6 Calculation and Adjustment of the Grid Management Charge**

The charges set forth in Section 11.22.2.5 that comprise the Grid Management Charge shall be calculated annually through the formula set forth in Appendix F, Schedule 1, Part A. The CAISO shall post on the CAISO Website each year, before the rates go into effect, as described in Appendix F, Schedule 1, Part D, data showing the adjustment to the rates to reflect any change in the annual revenue requirement, variance between forecast and actual costs for the previous year or period, or any surplus revenues from the previous year or period, or the inability to recover from a Scheduling Coordinator its share of the Grid Management Charge, or any under-achievement of a forecast of the billing determinant volumes used to establish the rates. Appendix F, Schedule 1, Part B sets forth the conditions under which a quarterly adjustment to the Grid Management Charge will be made.

**11.22.2.6.1 Credits and Debits of the Grid Management Charge**

In addition to the adjustments permitted under Section 11.29.7.3.3, the CAISO shall credit or debit, as appropriate, the account of a Scheduling Coordinator for any overpayment or underpayment of the Grid Management Charge that the CAISO determines occurred due to error, omission, or miscalculation by the CAISO or the Scheduling Coordinator.

### 11.22.3 [Not Used]

### 11.22.4 TOR Charges

The ISO will exempt TORs from the Market Services Charge and the System Operations Charge that are calculated through the formula set forth in Appendix F, Schedule 1, Part A. The TOR Charge will be $0.18/MWh, assessed on the minimum of a Scheduling Coordinator’s TOR supply or TOR demand per Settlement Interval. The TOR Charge is subject to adjustment as described in Appendix F, Schedule 1, Part A. The CAISO will credit amounts recovered through the TOR Charges against the revenue requirement for System Operations Charge as described in Appendix F, Schedule 1, Part A.

### 11.22.5 Bid Segment Fee

Each Scheduling Coordinator submitting a Bid will be subject to a Bid Segment Fee of $0.005 per segment of the Bid. The Bid Segment Fee is subject to adjustment as described in Appendix F, Schedule 1, Part A. The CAISO will credit amounts recovered through the Bid Segment Fee against the revenue requirement for Market Services Charge as described in Appendix F, Schedule 1, Part A.

### 11.22.6 CRR Transaction Fee

Each Scheduling Coordinator submitting a CRR Allocation nomination or CRR Auction bid will be subject to a CRR Transaction Fee of $1.00 per submitted nomination or bid. The CRR Transaction Fee is subject to adjustment as described in Appendix F, Schedule 1, Part A. The CAISO will credit amounts recovered through the CRR Transaction Fee against the revenue requirement for CRR Services Charge as described in Appendix F, Schedule 1, Part A.

### 11.22.7 Inter-Scheduling Coordinator Trade Transaction Fee

Each Scheduling Coordinator submitting an Inter-Scheduling Coordinator Trade will be subject to a Inter-Scheduling Coordinator Trade Transaction Fee of $1.00 per party per Inter-Scheduling Coordinator Trade. The Inter-Scheduling Coordinator Trade Transaction Fee is subject to adjustment as described in Appendix F, Schedule 1, Part A. The CAISO will credit amounts recovered through the Inter-Scheduling Coordinator Trade Transaction Fee against the revenue requirement for Market Services Charge as described in Appendix F, Schedule 1, Part A.

### 11.22.8 Scheduling Coordinator ID Charge

The Scheduling Coordinator ID Charge for each Scheduling Coordinator is $1,500.00 per month, per Scheduling Coordinator ID Code for any Trading Month in which the Scheduling Coordinator has market activity. The Scheduling Coordinator ID Charge is subject to adjustment as described in Appendix F, Schedule 1, Part A. The CAISO will credit amounts recovered through the Scheduling Coordinator ID Charges against the revenue requirement for Market Services Charges as described in Appendix F, Schedule 1, Part A.

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## 11.25 Settlement of Flexible Ramping Product

### 11.25.1 Settlement of Forecasted Movement

**11.25.1.1 Generally**

The CAISO will settle Forecasted Movement for a direction as specified in this Section 11.25.1 by

Balancing Authority Area for each Balancing Authority Area that has a distinct Uncertainty Requirement

for that direction, as specified in Section 44.2.4.1, and separately will settle Forecasted Movement for a

direction as specified in this Section 11.25.1 for the group of Balancing Authority Areas that shares a

common Uncertainty Requirement for that direction, as specified in Section 44.2.4.1.**11.25.1.2 FMM.**

The CAISO settles FMM Forecasted Movement with Scheduling Coordinators as the product of: (a) the difference between the FMM Forecasted Movement quantity and the DAM Forecasted Movement Quantity or Base Schedule Forecasted Movement quantity; and (b) the difference between the FMM Flexible Ramp Up Price and the FMM Flexible Ramp Down Price.

**11.25.1.3 RTD.**

The CAISO settles RTD Forecasted Movement with Scheduling Coordinators as the product of: (a) the difference between the RTD Forecasted Movement quantity and the FMM Forecasted Movement Quantity; and (b) the difference between the RTD Flexible Ramp Up Price and the RTD Flexible Ramp Down Price.

**11.25.1.4 Allocation of Residual Forecasted Movement Settlements.**

The CAISO will settle amounts remaining after settlement of Forecasted Movement pursuant to Section 11.25.1 to each Scheduling Coordinator’s metered EIM Demand or metered CAISO Demand in proportion to its share of the total metered EIM Demand and metered CAISO Demand.

### 11.25.2 Settlement of Uncertainty Requirement

**11.25.2.1 Payment to Resources.**

**11.25.2.1.1 FMM Uncertainty Awards**

For a resource with an IRU Award, the CAISO applies a deviation settlement as the product of the Flexible Ramp Up Price and the difference between the upward Five-minute Imbalance Reserve Quantity and the upward FMM Uncertainty Award.

For a resource with an IRD Award, the CAISO applies a deviation settlement as the product of the Flexible Ramp Down Price and the difference between the downward Five-minute Imbalance Reserve Quantity and downward FMM Uncertainty Award.

If a resource has no Imbalance Reserves Award, then the CAISO settles upward and downward Uncertainty Awards as the product of the Uncertainty Award and the Flexible Ramp Up Price, in the case of an upward Uncertainty Award, or the Flexible Ramp Down Price, in the case of a downward Uncertainty Award.

**11.25.2.1.2 RTD Uncertainty Awards**

The CAISO settles RTD Uncertainty Awards with Scheduling Coordinators as the algebraic sum of the upward uncertainty awards defined in part (a) of this Section 11.25.2.1.2 and the downward uncertainty awards defined in part (b) of this Section 11.25.2.1.2.

(a) Upward Uncertainty Awards – the product of the RTD Flexible Ramp Up Price and the difference between the upward RTD Uncertainty Award quantity and the upward FMM Uncertainty Award quantity for the relevant Settlement Interval, both calculated for each resource pursuant to Section 44.2 in MWhs, less any rescission amounts pursuant to section 11.25.3.

(b) Downward Uncertainty Awards – the product of the RTD Flexible Ramp Down Price and the difference between the downward RTD Uncertainty Award quantity and the downward FMM Uncertainty Award quantity for the relevant Settlement Interval, both calculated for each resource pursuant to Section 44.2 in MWhs, less any rescission amounts pursuant to section 11.25.3.

**11.25.2.2 Allocation of Costs of Uncertainty Movement Procured.**

**11.25.2.2.1 Settlement Process.**

(a) **Daily.** The CAISO will initially –

(1) allocate the cost of the Uncertainty Award within each Balancing Authority Area in the EIM Area and within the EIM Area on a daily basis according to the categories as set forth in this Section 11.25.2.2; and

(2) allocate the daily amounts to Scheduling Coordinators as set forth in this Section 11.25.2.2.

(b) **Monthly.** The CAISO will resettle the costs of the Uncertainty Awards by –

(1) reversing the daily allocation;

(2) assigning the monthly costs of the Uncertainty Awards to Peak Flexible Ramp Hours and Off-Peak Flexible Ramp Hours;

(3) separately allocating the monthly Peak Flexible Ramp Hours amounts and Off-Peak Flexible Ramp Hours amounts to the categories within each Balancing Authority Area in the EIM Area and within the EIM Area as set forth in this Section 11.25.2.2; and

(4) allocating the monthly amounts in each category to Scheduling Coordinators as set forth in this Section 11.25.2.2.

**11.25.2.2.2 Allocation of Charges to Categories.**

(a) **Determination of Uncertainty Movement for Resources.** For each interval, the CAISO will calculate the net Uncertainty Movement of each resource according to the following categories:

(1) for Supply resources other than non-Dynamic System Resources as the difference between the Dispatch Instruction of the binding interval in the next RTD run and the first advisory RTD interval in the current run.

(2) for non-Dynamic System Resources and export schedules as the difference between the schedule used in the RTD (accounting for ramp) for the binding interval in the next RTD run and the scheduled use for the first advisory interval in the current RTD run.

(b) **RTD Uncertainty Movement by Balancing Authority Area and by EIM Area.** The CAISO will determine the total net RTD Uncertainty Movement for each category separately for each Balancing Authority Area in the EIM Area and by EIM Area –

(1) for the category of Supply resources, which shall not include non-Dynamic System Resources, as the net sum of the five-minute Uncertainty Movement determined pursuant to Section 11.25.2.2.2 of all the Supply resources in the category.

(2) for the category of Intertie resources, which shall comprise non-Dynamic System Resources and exports, as the net sum of the five-minute Uncertainty Movement determined pursuant to Section 11.25.2.2 of all the non-Dynamic System resources and export schedules.

(3) for the non-Participating Load category, as the difference between –

(A) the CAISO Forecast of BAA Demand of the binding interval in the next RTD run; and

(B) CAISO Forecast of BAA Demand for the first advisory interval in the current RTD run.

**11.25.2.2.3 Assignment of Uncertainty Costs to Categories.**

The CAISO will allocate the total Uncertainty Award cost calculated pursuant to this section 11.25.2.2 to each category described in Section 11.25.2.2.2(b) based on –

(a) for upward Uncertainty Award cost, the ratio of such category’s positive Uncertainty Movement to the sum of the positive Uncertainty Movements of all categories with positive Uncertainty Movement for each Balancing Authority Area in the EIM Area and the EIM Area; and

(b) for downward Uncertainty Award costs, the ratio of such category’s negative Uncertainty Movement to the sum of the negative Uncertainty Movements of all categories with negative Uncertainty Movement for each Balancing Authority Area in the EIM Area and the EIM Area.

**11.25.2.2.4 Allocation to Scheduling Coordinators.**

(a) **Non-Participating Load Category.**  The CAISO will allocate the Uncertainty Awards costs of the non-Participating Load category to Scheduling Coordinators –

(1) for upward Uncertainty Award cost in proportion to the Scheduling Coordinator’s negative non-Participating Load UIE, excluding the non-Participating Load of an MSS that has elected to load-follow according to an MSS Agreement, without netting that UIE across Settlement Intervals, to the total of such negative non-Participating Load UIE, without netting that UIE across Settlement Intervals, in the Balancing Authority Area or EIM Area as applicable, and

(2) for downward Uncertainty Award cost calculated pursuant to Section 11.25, in proportion to the Scheduling Coordinator’s daily positive non-Participating Load UIE, excluding the non-Participating Load of an MSS that has elected to load-follow according to an MSS Agreement, without netting that UIE across Settlement Intervals, to the total of such positive non-Participating Load UIE, without netting that UIE across Settlement Intervals, in the BAA or EIM Area as applicable.

(b) **Supply Category.** The CAISO will allocate the Uncertainty Awards costs of the Supply category to Scheduling Coordinators for each resource in the Supply category based on the sum of the resource’s Uncertainty Movement and UIE –

(1) for upward Uncertainty Award cost in proportion to the Scheduling Coordinator’s positive sum of the resource’s Uncertainty Movement and UIE, without netting that sum across Settlement Intervals, to the total positive sum of all resources’ Uncertainty Movement and UIE, without netting that sum across Settlement Intervals, in the BAA or EIM Area as applicable; and

(2) for downward Uncertainty Award cost in proportion to the Scheduling Coordinator’s negative sum of the resource’s Uncertainty Movement and UIE, without netting that sum across Settlement Intervals, to the total negative sum of all resources’ Uncertainty Movement and UIE, without netting that sum across Settlement Intervals, in the Balancing Authority Area or EIM Area as applicable; except that

(3) for the MSS that have elected to load follow pursuant to an MSS Agreement, the CAISO will calculate the positive and negative sums specified above for each Settlement Interval as the sum of MSS non-Participating Load UIE, Supply resources within the MSS UIE, MSS Load Following Energy, MSS Load Following Operational Adjustments, and Uncertainty Movement of resources within the MSS Aggregation.

(c) **Intertie Category.** The CAISO will allocate the Uncertainty Awards costs of the Intertie category to Scheduling Coordinators for each non-Dynamic System Resource and export based on the sum of the resource’s Uncertainty Movement and Operational Adjustment –

(1) for upward Uncertainty Award cost in proportion to the magnitude of the Scheduling Coordinator’s negative Operational Adjustment for non-Dynamic System Resources, or positive Operational Adjustment for export resources, to the sum of the magnitudes of such Operational Adjustments in the Balancing Authority Area or EIM Area, without netting that sum across Settlement Intervals; and

(2) for downward Uncertainty Award cost in proportion to the magnitude of the Scheduling Coordinator’s positive Operational Adjustment for non-Dynamic System Resources, or negative Operational Adjustment for export resources, to the sum of the magnitudes of such Operational Adjustments in the Balancing Authority Area or EIM Area, without netting that sum across Settlement Intervals; and

(3) for the purposes of the allocations specified above, the MSS Load Following Operational Adjustment is excluded.

(d) **Uncertainty Award Cost Offset.**  If the sum of the settlement of Uncertainty Awards and the charges to Scheduling Coordinators for Uncertainty Award costs is nonzero, the CAISO will allocate such amounts to Scheduling Coordinators based on the ratio of their metered CAISO Demand and metered EIM Demand to the total EIM area metered demand.

### 11.25.3 Rescission

**11.25.3.1 Amount of Rescission.**

For each Settlement Interval in which a resource has either a UIE deviation or Operational Adjustment and a Flexible Ramping Product settlement, separately for upward and downward, the CAISO will rescind Settlement Amount for the overlap of the UIE or Operational Adjustment and the sum of RTD Forecasted Movement and Uncertainty Award, at the RTD FRUP or FRDP.

**11.25.3.2 Order of Rescission.**

For each Settlement Interval in which a resource has either a UIE deviation or Operational Adjustment and a Flexible Ramping Product settlement, separately for upward and downward, the CAISO will rescind Settlement Amount for the overlap of the UIE or Operational Adjustment and the sum of RTD Forecasted Movement and Uncertainty Award, at the RTD FRUP or FRDP.

### 11.25.4 [Not Used]

### 11.25.5 [Not Used]

\* \* \*

## 11.29 CAISO as Counterparty; Billing and Payment

\* \* \*

### 11.29.5 General Principles for Production of Settlement Statements

**11.29.5.1 Basis of Settlement**

The basis of each Settlement Statement will be the debiting or crediting of an account in the name of the relevant Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO.

**11.29.5.2 [Not Used]**

**11.29.5.3 Data Files**

Settlement Statements relating to each Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO will be accompanied by data files of supporting information that includes the following for each Settlement Period of the Trading Day:

(a) the aggregate quantity (in MWh) of Energy supplied or withdrawn by the Scheduling Coordinator Metered Entities represented by the Scheduling Coordinator;

(b) the aggregate quantity (in MW) and type of Ancillary Services capacity provided or purchased;

(c) the relevant prices that the CAISO has applied in its calculations;

(d) details of the scheduled quantities of Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services accepted by the CAISO in the Day-Ahead Market and the RTM;

(e) details of FMM Instructed Imbalance Energy or RTD Imbalance Energy and penalty payments;

(f) details of any payments or charges associated with the CRR Auctions; and

(g) detailed calculations of all fees, charges and payments allocated among Scheduling Coordinators and each Scheduling Coordinator’s share.

**11.29.5.4 Settlement Software**

The CAISO Settlement software will be audited by an independent firm of auditors competent to carry out audits of such software to determine its consistency with the CAISO Tariff. In any dispute regarding Settlement calculations, a certificate from the firm of auditors that the CAISO software is consistent with the CAISO Tariff will be prima facie proof that the charges shown in a Settlement Statement have been calculated in a method consistent with the CAISO Tariff. Nothing in this section will be deemed to establish the burden of proof with respect to Settlement calculations in any proceeding.

\* \* \*

### 11.29.17 Alternative Payment Procedures

**11.29.17.1 Pro Rata Reduction to Payments**

If it is not possible to clear the CAISO Clearing Account on a Payment Date because of nonpayment by a CAISO Debtor, which cannot be covered using funds available in the CAISO Reserve Account or the CAISO Penalty Reserve Account, or by enforcing any Financial Security provided by a defaulting CAISO Debtor, the CAISO shall, after deducting Grid Management Charge and FERC Annual Charges in accordance with Section 11.29.9.6.1 and paying amounts shown as due to internal accounts rather than to CAISO Creditors, such as the balancing accounts for CRRs, RAAIM or penalties issued under Section 37, (1) first pay in full every CAISO Creditor whose net amounts receivable on the relevant Payment Date is less than $5,000; and (2) second, reduce payments to all remaining CAISO Creditors proportionately to the net amounts payable to them on the relevant Payment Date to the extent necessary to clear the CAISO Clearing Account through a shortfall allocation. Each payment default amount allocated to CAISO Creditors through a shortfall allocation under this Section 11.29.17.1 that remains unpaid by the defaulting CAISO Debtor will be allocated as set forth in Section 11.29.17.2. The provisions of this Section 11.29.17.1 shall not apply to the extent the CAISO invokes Section 11.29.11 to direct a CAISO Debtor to not pay charges that are verifiably erroneous, or to non-payment of any penalty amount that a Scheduling Coordinator or CRR Holder has disputed and FERC has specifically authorized the Scheduling Coordinator or CRR Holder to net its payment to the CAISO by the amount of the penalty in question in accordance with Section 37.9.3.

**11.29.17.2 Payment Default Allocation**

**11.29.17.2.1 Methodology for Allocating Payment Default Amounts**

Each payment default amount allocated to CAISO Creditors through a shortfall allocation pursuant to Section 11.29.17.1 and that remains unpaid by the defaulting CAISO Debtor will be allocated on the next practicable Invoices to the Default-Invoiced SCIDs to which the percentage shares calculated pursuant to Section 11.29.17.2.7 for the current calendar quarter apply, excluding the CAISO Debtor that has not paid the payment default amount, pursuant to the following methodology:

(a) Twenty (20) percent of the payment default amount will be allocated to the Default-Invoiced SCIDs in proportion to the net amounts that were payable in each applicable calendar quarter (and averaged within such calendar quarter) to the Default-Invoiced SCIDs over the applicable Default Look-Back Periods. For Market Participants subject to Default Election option 1, these net amounts will be calculated on an SCID-by-SCID basis. For Market Participants that are eligible for and have chosen Default Election option 2, these net amounts will be calculated by consolidating all of the data for the applicable SCIDs, recognizing any offsetting effect of an individual SCID’s positive or negative dollar amount in the consolidated total.

(b) Thirty (30) percent of the payment default amount will be allocated to the Default-Invoiced SCIDs in proportion to the sum of the absolute values of the dollar amounts shown on their Invoices payable or receivable in each applicable calendar quarter (and averaged within such calendar quarter) over the applicable Default Look-Back Periods, after excluding dollar amounts shown on the Invoices for payments and charges for GMC, RMR, and Wheeling Access Charge costs, and after excluding the billing of Access Charges and the payment of Transmission Revenue Requirements to Participating Transmission Owners. For Market Participants subject to Default Election option 1, the sum of the absolute values of the dollar amounts shown on their Invoices payable or receivable in each applicable calendar quarter will be calculated on an SCID-by-SCID basis. For Market Participants that are eligible for and have chosen Default Election option 2, the absolute values of the net sum of the dollar amounts shown on their Invoices payable or receivable in each applicable calendar quarter will be calculated by consolidating all of the data for the applicable SCIDs, recognizing any offsetting effect of an individual SCID’s positive or negative dollar amount in the consolidated total.

(c) Fifty (50) percent of the payment default amount will be allocated to the Default-Invoiced SCIDs in proportion to the largest of the following five (5) amounts calculated in MWh for every month in each applicable calendar quarter (and averaged within such calendar quarter) for each Default-Invoiced SCID over the applicable Default Look-Back Periods:

(1) Cleared Day-Ahead Schedules to supply Energy, plus Day-Ahead Ancillary Services Awards and qualified Self-Provided Ancillary Services, plus scheduled supply obligation for Ancillary Services (including imports but excluding RUC Awards), plus Virtual Supply Awards;

(2) Metered Generation, plus Real-Time Interchange Import Schedules, plus Real-Time Ancillary Services Awards and qualified Self-Provided Ancillary Services, plus FMM Ancillary Services Awards and qualified Self-Provided Ancillary Services, plus Real-Time supply obligation for Ancillary Services;

(3) Cleared Day-Ahead Schedules for Demand (including Demand served by Pumped-Storage Hydro Units and exports) multiplied by one-hundred three (103) percent to reflect Transmission Losses, plus scheduled demand obligation for Ancillary Services, plus Virtual Demand Awards;

(4) Metered Load multiplied by one-hundred three (103) percent to reflect Transmission Losses, plus Real-Time Interchange Export Schedules, plus Real- Time demand obligation for Ancillary Services; or

(5) The greater of (A) the quantity of CRRs acquired in CRR Auctions or transferred through the Secondary Registration System (excluding CRRs acquired in CRR Allocations) or (B) Inter-SC Trades of Energy.

For Market Participants subject to Default Election option 1, each of the five (5) amounts calculated in MWh for every month in each applicable calendar quarter (and averaged within such calendar quarter) will be calculated on an SCID-by-SCID basis. For Market Participants that are eligible for and have chosen Default Election option 2, each of the five (5) amounts calculated in MWh for every month in each applicable calendar quarter (and averaged within such calendar quarter) will be calculated by consolidating all of the data for the applicable SCIDs.

**11.29.17.2.2 [Not Used]**

**11.29.17.2.3 Interest on Allocated Payment Default Amounts**

In accordance with Section 11.29.10.2, Interest will be charged to Default-Invoiced SCIDs pursuant to Section 11.29.17.2.1 or to SCIDs pursuant to Section 11.29.17.2.2 to the extent the payment default amounts allocated to those Default-Invoiced SCIDs or SCIDs exceed the payment default amounts allocated to them through a shortfall allocation pursuant to Section 11.29.17.1, and Interest will be paid to Default-Invoiced SCIDs pursuant to Section 11.29.17.2.1 or to SCIDs pursuant to Section 11.29.17.2.2 to the extent the payment default amounts allocated to those Default-Invoiced SCIDs or SCIDs are exceeded by the payment default amounts allocated to them through a shortfall allocation pursuant to Section 11.29.17.1, for the period between the date of the shortfall allocation and the date payments are due for the Invoices on which the allocation of the payment default amounts appear. The Interest payable pursuant to this Section 11.29.17.2.3 will be included on the Invoices on which the allocation of the payment default amounts appear.

**11.29.17.2.4 Default Election**

(a) Each Market Participant that is a Scheduling Coordinator, a CRR Holder, a Candidate CRR Holder, or a PTO will make an election of either option 1 or option 2 under this Section 11.29.17.2.4, which will be the Market Participant’s Default Election until such time as a subsequent change by the Market Participant of its Default Election from option 1 to option 2 (or vice versa) goes into effect. Each Market Participant that is a Scheduling Coordinator, a CRR Holder, a Candidate CRR Holder, or a PTO shall make only a single Default Election regardless of whether that Market Participant has multiple effective contracts with the CAISO that cause the entity to be a Market Participant. For example, an entity that has signed a Scheduling Coordinator Agreement and a CRR Entity Agreement shall only make a single Default Election.

(i) Option 1: For such Market Participants that choose Default Election option 1, the methodology for allocating payment default amounts set forth in Section 11.29.17.2.1 will apply to each SCID of such Market Participant on an SCID-by-SCID basis, and each SCID of such Market Participant will be a Default-Invoiced SCID.

(ii) Option 2: In order to qualify for Default Election option 2, all of the SCIDs of a Market Participant with one or more effective contracts with the CAISO must certify that they meet one of the following criteria, and the entity must agree that the methodology for allocating payment default amounts set forth in Section 11.29.17.2.1 will apply to all SCIDs created for use under all of the effective contracts with the CAISO based on a consolidation of data for all such SCIDs:

(1) All of the SCIDs are associated with Affiliates or business units under common control where one or more of the Affiliates or business units or a related business entity has more than fifty (50) percent control of the Affiliates or business units, either directly or through one or more intermediaries;

(2) All of the SCIDs are associated with a Joint Powers Authority; or

(3) All of the SCIDs are associated with a municipal utility or state or federal agency.

Each Market Participant that chooses Default Election option 2 will at the same time select a single SCID to be the sole Default-Invoiced SCID under option 2. This Default-Invoiced SCID will receive Invoices containing payment default amounts allocated on behalf of all of the SCIDs under all contracts between the entity and the CAISO. Allocation of payment default amounts for entities choosing Default Election option 2 will be based on consolidated data from all of the entity’s SCIDs. The selection of a single SCID as the sole Default-Invoiced SCID will not in any way relieve any Market Participant subject to Default Election option 2 of any obligation to pay Invoices, including in the event of a default by the Default-Invoiced SCID on a default payment obligation, in which case the CAISO will be entitled to utilize all available Financial Security provided by any defaulting Market Participant subject to Default Election option 2.

(b) [Not Used]

(c) Market Participants may change their Default Elections by October 1 of each calendar year by notifying the CAISO, to become effective on January 1 of the next calendar year. Market Participants that do not change their Default Elections by that date will be deemed to have chosen to continue their current Default Elections.

(d) Each entity that becomes a Scheduling Coordinator, a CRR Holder, a Candidate CRR Holder, or a PTO after one of the dates set forth in Section 11.29.17.2.4(a), -(b), or -(c) will make its Default Election prior to engaging in any transactions in the CAISO Markets. The Default Election of each such entity will remain in effect until the entity makes another Default Election pursuant to this Section 11.29.17.2.4. However, any Market Participant that has already made a Default Election will not be eligible to change its Default Election as a result of its subsequently also becoming a Scheduling Coordinator, a CRR Holder, a Candidate CRR Holder, or a PTO.

(e) Market Participants that do not timely inform the CAISO of their initial Default Elections will be deemed to have chosen Default Election option 1.

**11.29.17.2.5 Effect of Change in Default Election**

Each time that a Market Participant changes its Default Election pursuant to Section 11.29.17.2.4 from option 1 to option 2 (or vice versa), the following provisions will apply:

(a) For the first quarter of the calendar year after the change in Default Election goes into effect, the Default-Invoiced SCID(s) will be allocated shares of payment default amounts calculated pursuant to Section 11.29.17.2.1 based on application of the prior election to the first three (3) full calendar quarters of data within the Default Look-Back Period and application of the new election to the most recent full calendar quarter of data within the Default Look-Back Period.

(b) For the second quarter of the calendar year after the change in Default Election goes into effect, the Default-Invoiced SCID(s) will be allocated shares of payment default amounts calculated pursuant to Section 11.29.17.2.1 based on application of the prior election to the first two (2) full calendar quarters of data within the Default Look-Back Period and application of the new election to the most recent two (2) full calendar quarters of data within the Default Look-Back Period.

(c) For the third quarter of the calendar year after the change in Default Election goes into effect, the new Default-Invoiced SCID(s) will be allocated shares of payment default amounts calculated pursuant to Section 11.29.17.2.1 based on application of the prior election to the first full calendar quarter of data within the Default Look-Back Period and application of the new election to the most recent three (3) full calendar quarters of data within the Default Look-Back Period.

(d) For the fourth quarter of the calendar year after the change in Default Election goes into effect, the Default-Invoiced SCID(s) will be allocated shares of payment default amounts calculated pursuant to Section 11.29.17.2.1 based on application of the new election to the entire Default Look-Back Period.

**11.29.17.2.6 Default Look-Back Period**

(a) The following provisions will apply to each Default-Invoiced SCID for an entity that is a new Market Participant that begins to participate in the CAISO Markets following the effective date of this Section 11.29.17.2.6:

(i) The Default-Invoiced SCID for that Market Participant will first be subject to allocation of payment default amounts under Section 11.29.17.2.1 in the second calendar quarter following the calendar quarter in which the Market Participant begins to participate in the CAISO Markets and the applicable Default Look-Back Period will be the calendar quarter in which the Market Participant began to participate in the CAISO Markets.

(ii) For each payment default that occurs in the third calendar quarter following the calendar quarter in which the Market Participant begins to participate in the CAISO Markets, the applicable Default Look-Back Period will be the Market Participant’s first two (2) calendar quarters of participation in the CAISO Markets.

(iii) For each payment default that occurs in the fourth calendar quarter following the calendar quarter in which the Market Participant begins to participate in the CAISO Markets, the applicable Default Look-Back Period will be the Market Participant’s first three (3) calendar quarters of participation in the CAISO Markets.

(iv) For each payment default that occurs in any subsequent calendar quarter in which Section 11.29.17.2.1 is in effect, the applicable Default Look-Back Period will be the most recent four (4) full calendar quarters for which T+70B data are available.

**11.29.17.2.7 Provision of Information on Percentage Shares**

Beginning with the second calendar quarter of 2011, the CAISO will provide to each Default-Invoiced SCID on or about the first Business Day of the applicable calendar quarter its own percentage share of any payment default amount that may be allocated in the calendar quarter to which the percentage share applies, subject to adjustment to account for any non-paying CAISO Debtor, based on application of the methodology for allocating payment default amounts set forth in Section 11.29.17.2.1 to the applicable Default Look-Back Period. In calculating the percentage share for each Default-Invoiced SCID pursuant to this Section 11.29.17.2.7, the CAISO will determine the percentage share for each full calendar quarter and will average those quarterly percentage shares.

**11.29.17.2.8 Scope of Payment Default Allocation Provisions**

The provisions of Section 11.29.17.2 will not apply to the allocation of payment default amounts and interest accrued thereon that are associated with Trading Days that occurred prior to April 1, 2009.

**11.29.17.3 Payment of Defaulted Receivables**

Collections of defaulted receivables (other than Interest) will either be distributed *pro rata* to CAISO Creditors for the Payment Advices that were subject to default or, if the defaulted receivables are allocated pursuant to Section 11.29.17.2, collections of the defaulted receivables will be distributed to Default-Invoiced SCIDs in proportion to their allocated shares of the defaulted receivables as calculated pursuant to Section 11.29.17.2.1 for the Payment Advice on which the payment default occurred.

(1) If the total collected in that closing related to the past due Payment Advice is less than $5,000, then the funds shall accumulate in an interest-bearing account until either: (a) the account exceeds $5,000, (b) there have been no distributions from the account for six months, or (c) all defaults for that month have been collected exclusive of any bankruptcy defaults.

(2) If all CAISO Creditors for that Payment Advice have been paid, then the proceeds will either be paid *pro rata* to the CAISO Creditors in the oldest unpaid Payment Advice, or, if the defaulted receivables are allocated pursuant to Section 11.29.17.2, the proceeds will be paid to the Default-Invoiced SCIDs in proportion to their allocated shares of the default amount, as calculated pursuant to Section 11.29.17.2.1 in the oldest unpaid Payment Advice.

(3) This provision is also applicable to the amounts netted against CAISO Creditor balances related to prior defaulted receivables.

(4) All defaulted receivables disbursed under this Section shall be disbursed in accordance with the timeframes set forth in Section 11.29.9.6.1.

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# 27. CAISO Markets and Processes

In the Day-Ahead and Real-Time time frames the CAISO operates a series of procedures and markets that together comprise the CAISO Markets Processes. In the Day-Ahead time frame, the CAISO conducts the Market Power Mitigation (MPM) process, the Integrated Forward Market (IFM) and the Residual Unit Commitment (RUC) process. In the Real-Time time frame, the CAISO does the following: 1) accepts the Economic Bids and Self-Schedules used in the Real-Time Market procedures, 2) conducts the MPM process for the RTM, 3) accepts and awards HASP Block Intertie Schedules for Energy and Ancillary Services, 4) provides HASP Advisory Schedules for Energy and Ancillary Services for Bids that do not create a HASP Block Intertie Schedule, 5) conducts the Real-Time Unit Commitment (RTUC), 6) conducts the Short-Term Unit Commitment (STUC), 7) conducts the Fifteen Minute Market (FMM), and 8) conducts the five-minute Real-Time Dispatch (RTD). As appropriate, the CAISO Markets Processes utilize transmission and Security Constrained Unit Commitment and dispatch algorithms in conjunction with a Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 to optimally commit, schedule and Dispatch resources and determine marginal prices for Energy, Imbalance Reserves, Ancillary Services and RUC Capacity. Congestion Revenue Rights are available and entitle holders of such instruments to a stream of hourly payments or charges associated with revenue the CAISO collects or pays from the Marginal Cost of Congestion component of hourly Day-Ahead LMPs for Energy, Locational IRU Prices, and Locational IRD Prices. Through the operation of the CAISO Markets Processes the CAISO develops Day-Ahead Schedules, Imbalance Reserves Awards, Day-Ahead AS Awards and RUC Schedules, HASP Block Intertie Schedules for Energy and AS Awards, HASP Advisory Schedules, FMM Energy Schedules, and FMM Ancillary Services Awards, Real-Time AS Awards and Dispatch Instructions to ensure that sufficient supply resources are available in Real-Time to balance Supply and Demand and operate in accordance with Reliability Criteria.

## 27.1 LMPs and Ancillary Services Marginal Prices

Through the workings of CAISO Market Processes, the CAISO produces: 1) Locational Marginal Prices as provided in Section 27.1.1 and its subparts, and as further provided in Appendix C; and 2) Ancillary Services Marginal Prices as provided below in Section 27.1.2, and its subparts.

**27.1.1 Locational Marginal Prices for Energy**

As further described in Appendix C, the LMP for Energy at any PNode is the marginal cost of serving the next increment of Demand at that PNode calculated by the CAISO through the operations of the CAISO Markets considering, as described further in the CAISO Tariff, among other things, modeled Transmission Constraints (including Remedial Action Schemes), transmission losses, the performance characteristics of resources, and Bids submitted by Scheduling Coordinators and as modified through the Locational Market Power Mitigation process. The LMP at any given PNode is comprised of three marginal cost components: the System Marginal Energy Cost (SMEC); Marginal Cost of Losses (MCL); and Marginal Cost of Congestion (MCC). Through the IFM the CAISO calculates LMPs for each Trading Hour of the next Trading Day. Through the FMM the CAISO calculates distinct financially binding fifteen-minute LMPs for each of the four fifteen-minute intervals within a Trading Hour. Through the Real-Time Dispatch, the CAISO calculates five-minute LMPs for each of the twelve (12) five (5) minute Dispatch Intervals of each Trading Hour. The CAISO uses the FMM or RTD LMPs for Settlements of the Real-Time Market.

**27.1.1.1 System Marginal Energy Cost**

The System Marginal Energy Cost (SMEC) component of the LMP reflects the marginal cost of providing Energy from a designated reference Location. For this designated reference Location the CAISO will utilize a distributed Reference Bus whose constituent PNodes are weighted in proportions referred to as Reference Bus distribution factors. The SMEC shall be the same throughout the system.

**27.1.1.2 Marginal Cost Losses**

For all PNodes and Aggregated PNodes in the CAISO Balancing Authority Area, including Scheduling Points, the use of the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 in the DAM and the RTM processes incorporates Transmission Losses. At each PNode or Aggregated PNode, the Marginal Cost of Losses is the System Marginal Energy Cost multiplied by the Marginal Loss factor at that PNode or Aggregated PNode. The Marginal Cost of Losses at a Location (PNode or APNode) may be positive or negative depending on whether an increase in Demand at that Location marginally increases or decreases the cost of Transmission Losses, using the distributed Reference Bus to balance it. The Marginal Loss factors are determined through a process that calculates the sensitivities of Transmission Losses with respect to changes in injection at each Location in the FNM. For CAISO Controlled Grid facilities outside the CAISO Balancing Authority Area, the CAISO shall assess the cost of Transmission Losses to Scheduling Coordinators using each such facility based on the quantity of losses agreed upon with the neighboring Balancing Authority multiplied by the LMP at the PNode of the Transmission Interface with the neighboring Balancing Authority Area. The MCLs calculated for Locations within the CAISO Balancing Authority Area shall not reflect the cost of Transmission Losses on those facilities.

**27.1.1.3 Marginal Cost of Congestion**

The Marginal Cost of Congestion at a PNode reflects a linear combination of the Shadow Prices of the binding Transmission Constraints (including Remedial Action Schemes) in the network, multiplied by the corresponding Power Transfer Distribution Factor (PTDF) and coefficient relevant to the transmission segment within that constraint, which is described in Appendix C. The Marginal Cost of Congestion for a Transmission Constraint may be positive or negative depending on whether a power injection at that Location marginally increases or decreases Congestion.

**27.1.1.4 Disconnected Pricing Node or Aggregated Pricing Node**

In the event that a Pricing Node or Aggregated Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the System Marginal Energy Cost, Marginal Cost of Congestion and Marginal Cost of Losses, at the closest electrically connected Pricing Node will be used as the LMP at the affected location. The CAISO will include the impact of the disconnected Pricing Node on any modeled Remedial Action Scheme in determining the LMP.

**27.1.2 Ancillary Service Prices**

**27.1.2.1 Ancillary Service Marginal Prices – Sufficient Supply**

As provided in Section 8.3, Ancillary Services are procured and awarded through the IFM and the FMM, and the CAISO also accepts and awards HASP Block Intertie Schedules for Ancillary Services in HASP. Ancillary Services awarded through HASP are made financially binding in the FMM. The IFM calculates hourly Day-Ahead Ancillary Service Awards and establishes Ancillary Service Marginal Prices (ASMPs) for the accepted Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve Bids. The IFM co-optimizes Energy, Imbalance Reserves, and Ancillary Services subject to resource, network and regional constraints. In the HASP, the CAISO accepts and awards Ancillary Services from HASP Block Intertie Schedules for the next Trading Hour as described in Section 34.2. The CAISO calculates the price for the settlement of Ancillary Services accepted and awarded in HASP based on the FMM ASMP as described herein and further described in Section 34.4. The FMM process that is performed every fifteen (15) minutes establishes fifteen (15) minute Ancillary Service Schedules, Awards, and prices for the upcoming quarter of the given Trading Hour. ASMPs are determined by first calculating Shadow Prices of Ancillary Services for each Ancillary Service type and the applicable Ancillary Services Regions. The Ancillary Services Shadow Prices are produced as a result of the co-optimization of Energy and Ancillary Services through the IFM and the Real-Time Market, subject to resource, network, and requirement constraints. The Ancillary Services Shadow Prices represent the marginal cost of the relevant binding regional constraints at the optimal solution, or the reduction of the combined Energy and Ancillary Service procurement cost associated with a marginal relaxation of that constraint. If the constraint for an Ancillary Services Region is not binding, the corresponding Ancillary Services Shadow Price in the Ancillary Services Region is zero (0). During periods in which supply is sufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region is then the sum of the Ancillary Services Shadow Prices for the specific type of Ancillary Service and all the other types of Ancillary Services for which the subject Ancillary Service can substitute, as described in Section 8.2.3.5, for the given Ancillary Service Region and all the other Ancillary Service Regions that include that given Ancillary Service Region. During periods in which supply is insufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region will reflect the Scarcity Reserve Demand Curve Values set forth in Section 27.1.2.3.

**27.1.2.2 Opportunity Cost in ASMP**

The Ancillary Services Shadow Price, which, as described above, is a result of co-optimizing procurement of Energy, Imbalance Reserves, and Ancillary Services, includes the foregone opportunity cost of the marginal resource, if any, for not providing Energy, Imbalance Reserves, or Ancillary Services the marginal resource is capable of providing in the relevant market. The ASMPs determined by the IFM or FMM optimization process for each resource whose Ancillary Service Bid is accepted will be no lower than the sum of (i) the Ancillary Service capacity Bid price submitted for that resource, and (ii) the foregone opportunity cost of Energy or Imbalance Reserves in the IFM or Energy and FRP in the FMM for that resource. The foregone opportunity cost of Energy or Imbalance Reserves for this purpose is measured as the positive difference between the price in the relevant market for the given product at the resource’s Pricing Node and the resource’s Bid price in the relevant market for the given product. If the Bid price for the resource is higher than the LMP, the opportunity cost measured for this calculation is $0. If a resource has submitted an Ancillary Service Bid but no Energy Bid and this Tariff obligates the resource to submit Bids for Energy in the Day-Ahead Market, then the CAISO inserts an Energy Bid at its Default Energy Bid and the CAISO calculates its opportunity cost based on that Default Energy Bid. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is not under an obligation to offer Energy in the Day-Ahead Market, its Energy opportunity cost measured for this calculation is $0 since it cannot be dispatched for Energy. For Self-Scheduled Hourly Block Bids for Ancillary Services awarded in the Real-Time Market, the opportunity cost measured for this purpose is $0 because, as provided in Section 34.2.3, the CAISO cannot Schedule Energy in the Real-Time Market from the Energy Bid under the same Resource ID as the submitted Ancillary Service Bid.

**27.1.2.3 Ancillary Services Pricing – Insufficient Supply**

The CAISO will develop Scarcity Reserve Demand Curves as further described in an applicable Business Practice Manual that will apply to both the Day-Ahead Market and the Real-Time Market during periods in which supply is insufficient to meet the minimum procurement requirements for Regulation Down, Non-Spinning Reserve, Spinning Reserve and Regulation Up as required by Section 8.3. The CAISO shall review the performance of the Scarcity Reserve Demand Curves and assess whether changes are necessary every three (3) years or more frequently, if the CAISO determines more frequent reviews are appropriate. When supply is insufficient to meet any of the minimum procurement requirements for Regulation Down, Non-Spinning Reserve, Spinning Reserve and Regulation Up, the Scarcity Reserve Demand Curve Values for the affected Ancillary Services, as set forth in this Section 27.1.2.3 and as reflected in the Scarcity Demand Curve Value described in Section 27.1.2.3.5, shall apply to determine the Shadow Prices of the affected Ancillary Services. ASMPs for an Ancillary Service type will not sum these Shadow Prices across Ancillary Service Regions, if there is insufficient supply for the Ancillary Service type in both the Expanded System Region and an Ancillary Service Sub-Region.

**27.1.2.3.1 Regulation Down Pricing – Insufficient Supply**

When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region or in an Ancillary Service Sub-Region is less than or equal to thirty-two (32) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be fifty (50) percent of the Soft Energy Bid Cap or the Hard Energy Bid Cap, as applicable based on the conditions specified in Sections 27.4.3.2 and 27.4.3.3, as specified in the tables in Section 27.1.2.3.5. When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region is less than or equal to eighty-four (84) MW but greater than thirty-two (32) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be sixty (60) percent of the Soft Energy Bid Cap of the Hard Energy Bid Cap, as applicable based on the conditions specified in Section 27.4.3.2 and 27.4.3.3, as specified in the tables in Section 27.1.2.3.5. When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region is greater than eighty-four (84) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be seventy (70) percent of the Soft Energy Bid Cap or the Hard Energy Bid Cap, as applicable based on the conditions specified in Section 27.4.3.2 and 27.4.3.3, as specified in the tables in Section 27.1.2.3.5.

**27.1.2.3.2 Non-Spinning Reserve Pricing – Insufficient Supply**

When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region or in an Ancillary Service Sub-Region is less than or equal to seventy (70) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be fifty (50) percent of the Soft Energy Bid Cap or the Hard Energy Bid Cap, as applicable based on the conditions specified in Section 27.4.3.2 and 27.4.3.3, as specified in the tables in Section 27.1.2.3.5. When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region is less than or equal to two-hundred ten (210) MW but greater than seventy (70) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be sixty (60) percent of the Soft Energy Bid Cap or the Hard Energy Bid Cap, as applicable based on the conditions specified in Sections 27.4.3.2 and 27.4.3.3, as specified in the tables in Section 27.1.2.3.5. When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region is greater than two-hundred ten (210) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be seventy (70) percent of the Soft Energy Bid Cap or the Hard Energy Bid Cap, as applicable based on the conditions specified in Section 27.4.3.2 and 27.4.3.3, as specified in the tables in Section 27.1.2.3.5.

**27.1.2.3.3 Spinning Reserve Pricing – Insufficient Supply**

The Scarcity Reserve Demand Curve Value for Spinning Reserve in the Expanded System Region or in an Ancillary Service Sub-Region shall be ten (10) percent of the Soft Energy Bid Cap or the Hard Energy Bid Cap, as applicable based on the conditions specified in Section 27.4.3.2 and 27.4.3.3, as specified in the tables in Section 27.1.2.3.5.

**27.1.2.3.4 Regulation Up Pricing – Insufficient Supply**

The Scarcity Reserve Demand Curve Value for Regulation Up in the Expanded System Region or in an Ancillary Service Sub-Region shall be twenty (20) percent of the Soft Energy Bid Cap or the Hard Energy Bid Cap, as applicable based on the conditions specified in Section 27.4.3.2 and 27.4.3.3, as specified in Section 27.1.2.3.5.

**27.1.2.3.5 Scarcity Demand Curve Value Tables**

|  |
| --- |
| **Scarcity Demand Curve Value ($/MWh) When Energy Pricing Parameters based on Soft Energy Bid Cap as Specified In Section 27.4.3.2** |
|  | **Percent of Soft Energy Bid Cap** |  |
| **Reserve** | **Expanded System Region** | **System Region and Sub-Region** | **Expanded System Region** | **System Region and Sub-Region** |
| Regulation Up | 20% | 20% | $200 | $200 |
| Spinning | 10% | 10% | $100 | $100 |
| Non-Spinning Shortage > 210 MW | 70%  | 70% | $700 | $700 |
| Non-Spinning Shortage > 70 & ≤ 210 MW | 60%  | 60%  | $600 | $600 |
| Non-Spinning Shortage  ≤ 70 MW | 50% | 50% | $500  | $500 |
| **Upward Sum** | **100%** | **100%** | **$1000** | **$1000** |
| Regulation Down Shortage > 84 MW | 70%  | 70%  | $700 | $700 |
| Regulation Down Shortage > 32 & ≤ 84 MW | 60% | 60%  | $600 | $600 |
| Regulation Down Shortage ≤ 32 MW | 50% | 50% | $500 | $500 |

|  |
| --- |
| **Scarcity Demand Curve Value ($/MWh) When Energy Pricing Parameters based on Hard Energy Bid Cap as Specified In Section 27.4.3.3** |
|  |  |
|  | **Percent of Hard Energy Bid Cap** |  |
| **Reserve** | **Expanded System Region** | **System Region and Sub-Region** | **Expanded System Region** | **System Region and Sub-Region** |
| Regulation Up | 20% | 20% | $400 | $400 |
| Spinning | 10% | 10% | $200 | $200 |
| Non-Spinning Shortage > 210 MW | 70%  | 70% | $1,400 | $1,400 |
| Non-Spinning Shortage > 70 & ≤ 210 MW | 60%  | 60%  | $1,200 | $1,200 |
| Non-Spinning Shortage  ≤ 70 MW | 50% | 50% | $1,000 | $1,000 |
| **Upward Sum** | **100%** | **100%** | **$2,000** | **$2,000** |
| Regulation Down Shortage > 84 MW | 70%  | 70%  | $1,400 | $1,400 |
| Regulation Down Shortage > 32 & ≤ 84 MW | 60% | 60%  | $1,200 | $1,200 |
| Regulation Down Shortage ≤ 32 MW | 50% | 50% | $1,000 | $1,000 |

**27.1.2.4 Opportunity Cost in LMPs for Energy**

In the event that there is insufficient supply to meet an Ancillary Services procurement requirement in a particular Ancillary Service Region or Sub-Region, the Ancillary Services Shadow Prices will rise automatically to the Scarcity Reserve Demand Curve Values in that Ancillary Service Region or Sub-Region. LMPs for Energy will reflect the forgone opportunity cost of the marginal resource, if any, for not providing other products procured in the IFM

**27.1.3 Regulation Mileage Clearing Price**

As provided in Section 8.3, Regulation Up and Regulation Down are procured and awarded through the Day Ahead Market and Real-Time Market. The CAISO will calculate uniform Mileage clearing prices for Regulation Up and Regulation Down, respectively, based on the intersection of the demand curve for Mileage requirements and supply curve for Bid-in Mileage. These uniform Mileage clearing prices shall apply to the CAISO Expanded System Region.

The CAISO will calculate a System Mileage Multiplier for Regulation Up by summing the total Mileage provided by all resources with Regulation Up awards each week for a corresponding hour of each Trading Day and then dividing that sum by the Regulation Up capacity procured for that week in that same hour. The CAISO will calculate a System Mileage Multiplier for Regulation Down by summing the total Mileage provided by all resources with Regulation Down awards each week for a corresponding hour of each Trading Day and then dividing that sum by the Regulation Down capacity procured for that week in that same hour. For purposes of these calculations, the CAISO shall calculate each week using a rolling seven-day period. The CAISO will use the System Mileage Multiplier to assess Mileage requirements for Regulation Up and Regulation Down capacity.

The CAISO will calculate resource specific Mileage multipliers and apply these multipliers to resources’ Bid-in Regulation Up and Regulation Down capacity. The resource specific Mileage multipliers will reflect resources’ Historic Regulation Performance Accuracy and certified 10-minute ramp capability. The CAISO will apply resource specific Mileage multipliers to Bid-in Regulation Up and Regulation Down capacity to determine the expected Mileage. In the event that an existing certified resource has not provided Regulation over the prior thirty (30) days, the CAISO will use the resource’s last Historic Regulation Performance Accuracy as an adjustment factor. For newly certified or recertified resources, the CAISO will use the simple average Historic Regulation Performance Accuracy for all resources from the prior thirty (30) days as an initial adjustment factor. Upon request, the CAISO will provide a resource with historical data used to derive its Mileage multipliers. A resource will receive a Mileage award that is at least as much as its self-provided or awarded Regulation Up or Regulation Down capacity, but not more than the product of its resource specific mileage multiplier and its self-provided or awarded capacity. The CAISO may adjust resource specific Mileage multipliers to align a resource’s awarded Mileage with the resource’s expected Mileage. The CAISO will use Mileage awards to determine a uniform clearing mileage price for Regulation Up and Regulation Down, but the Mileage quantity awards will not be financially binding. Resources will receive payments based upon Instructed Mileage as calculated pursuant to Section 11.10.1.7. The CAISO will publish on OASIS the Mileage clearing prices for each hour of the Day-Ahead Market and each fifteen (15) minute period in Real-Time for the Trading Day.

**27.1.4 Locational IRU Price and Locational IRD Price**

As further described in Appendix C, the Locational IRU Price or Locational IRD Price at any PNode is the marginal cost of procuring the next increment of IRU or IRD, respectively, at that PNode calculated by the CAISO through the operations of the CAISO Markets considering, as described further in the CAISO Tariff, among other things, modeled Transmission Constraints (including Remedial Action Schemes), the performance characteristics of resources, and Imbalance Reserves Bids submitted by Scheduling Coordinators as modified by the IFM MPM. The Locational IRU Price or Locational IRD Price at a PNode is comprised of two marginal cost components: (1) the Shadow Price of the IRU or IRD procurement constraint for the relevant BAA in the EDAM Area; and (2) the MCC for IRU or IRD.

**27.1.5 Locational RCU Price and Locational RCD Price**

As further described in Appendix C, the Locational RCU Price or Locational RCD Price at any PNode is the marginal cost of procuring the next increment of RCU or RCD, respectively, at that PNode calculated by the CAISO through the operations of the CAISO Markets considering, as described further in the CAISO Tariff, among other things, modeled Transmission Constraints (including Remedial Action Schemes), the performance characteristics of resources, and RUC Availability Bids submitted by Scheduling Coordinators as modified by the RUC MPM. The Locational RCU Price or Locational RCD Price at a PNode is comprised of three marginal cost components: (1) the Shadow Price of the RUC power balance constraint for the relevant BAA in the EDAM Area; (2) the Marginal Cost of Losses; and (3) the MCC for RCU or RCD.**27.2 Load Aggregation Points (LAP)**

The CAISO shall create Load Aggregation Points and shall maintain Default LAPs at which all Demand shall Bid and be settled, except as provided in Sections 27.2.1 and 30.5.3.2.

**27.2.1 Metered Subsystems**

The CAISO shall define specific MSS LAPs for each MSS. The MSS LAP shall be made up of the PNodes within the MSS that have Load served off of those Nodes. The MSS LAPs have unique Load Distribution Factors that reflect the distribution of the MSS Demand to the network Nodes within the MSS. These MSS LAPs are separate from the Default LAPs, and the Load Distribution Factors of the Default LAP do not reflect any MSS Load. As further provided in Sections 11.2.3 and 11.5, MSS Demand is settled either at the price at the Default LAP for MSS Operators that have selected gross Settlement or at the price at the applicable MSS LAP for MSS Operators that have selected net Settlement.

**27.2.2 Determination of LAP Prices**

**27.2.2.1 IFM LAP Prices**

The IFM LAP Price for Settlement of Demand at any LAP for a given Trading Hour is the price as produced by the IFM optimization run based on the distribution of system Load at the constituent Pricing Nodes within the applicable LAP and is determined by the effectiveness of the Load within the LAP in relieving a Transmission Constraint within the effectiveness threshold as specified in Section 27.4.3.6.

**27.2.2.2 Real-Time Market LAP Prices**

The FMM LAP Price and RTD LAP Price for a fifteen-minute FMM interval and five minute Dispatch Interval is the price as produced by the FMM and RTD optimization runs, respectively, based on the distribution of system Load at the constituent Pricing Nodes within the applicable LAP and is determined by the effectiveness of the Load within the LAP in relieving a Transmission Constraint within the effectiveness threshold as specified in Section 27.4.3.6. The Hourly Real-Time LAP Price is then determined for Settlement purposes as further described in Section 11.5.2.2.

**27.3 Trading Hubs**

The CAISO shall create and maintain Trading Hubs, including Existing Zone Generation Trading Hubs, to facilitate bilateral Energy transactions in the CAISO Balancing Authority Area. Each Trading Hub will be based on a pre-defined set of PNodes. The CAISO Market run will produce a Trading Hub price for each Settlement Period or Settlement Interval that is derived from the CAISO Market optimization based on the effectiveness of the Trading Hub aggregation in relieving congestion. The Trading Hub price will reflect congestion on Transmission Constraints whose effectiveness factor for the respective Trading Hub is greater than the effectiveness threshold specified in Section 27.4.3.6. There are three Existing Zone Generation Trading Hubs, which correspond geographically to the three Existing Zones. Each Existing Zone Generation Trading Hub is comprised of an aggregation of PNodes for Generating Units within the corresponding Existing Zone. The specification of seasons will be identical to the seasons used in the annual CRR Allocation, and the annual calculation of Existing Zone Generation Trading Hub weights will be performed in a timely manner to be coordinated with the annual CRR Allocation and CRR Auction processes.

**27.4 Optimization in the CAISO Market Processes**

The CAISO runs the Day-Ahead Market and Real-Time Market and their component CAISO Markets Processes utilizing a set of integrated optimization programs, including SCUC and SCED.

**27.4.1 Security Constrained Unit Commitment**

The CAISO uses SCUC to run the MPM process associated with the DAM and the RTM. SCUC is conducted over multiple varying intervals to commit and schedule resources as follows: (1) in the Day-Ahead time frame, to meet Demand reflected in Bids submitted in the Day-Ahead Market and considered in the MPM process and IFM, and to procure AS in the IFM; (2) to meet the CAISO Forecast of CAISO Demand in the RUC, HASP, STUC and FMM, and in the MPM process utilized in the HASP and RTM; and (3) to procure any incremental AS in the RTM, and (4) to procure Flexible Ramping Product in the RTM. In the Day-Ahead MPM, IFM and RUC processes, the SCUC commits resources over the twenty-four (24) hourly intervals of the next Trading Day. In the FMM, which runs every fifteen (15) minutes and commits resources for the RTM, the SCUC optimizes over a number of 15-minute intervals corresponding to the Trading Hours for which the Real-Time Markets have closed. The Trading Hours for which the Real-Time Markets have closed consist of (a) the Trading Hour in which the applicable run is conducted and (b) all the fifteen-minute intervals of the entire subsequent Trading Hour. In the HASP, which runs once per hour, the SCUC: (1) accepts and awards HASP Block Intertie Schedules for Energy and Ancillary Services, respectively; (2) provides HASP Advisory Schedules to Economic Hourly Block Bids with Intra-Hour Option that will change for economic reasons at most once in the Trading Hour; and (3) provides HASP Advisory Schedules to all other participants in the RTM. In the STUC, which runs once an hour, the SCUC commits resources over the last fifteen (15) minutes of the imminent Trading Hour and the entire next four Trading Hours. The CAISO will commit Extremely Long Start Resources, for which commitment in the DAM does not provide sufficient time to Start-Up and be available to supply Energy during the next Trading Day as provided in Section 31.7.

**27.4.1.1 Timing of Unit Commitment Instructions**

For the applicable market intervals of any given CAISO Markets Process, the associated SCUC optimization will typically commit resources having different Start-Up Times, not all of which need to be started up immediately upon completion of that CAISO Markets Process. The CAISO may defer issuing a Start-Up Instruction to a resource that can be started at a later time and still be available to supply Energy at the time the CAISO Markets Process indicated it would be needed. The CAISO shall re-evaluate the need to commit such resources in a subsequent CAISO Markets Process based on the most recent forecasts and other information about system conditions.

**27.4.2 Security Constrained Economic Dispatch**

SCED is the optimization engine used to run the RTD to determine the optimal five-minute Dispatch Instructions throughout the Trading Hour consistent with resource constraints and Transmission Constraints within the CAISO Balancing Authority Area. In any given hour, the Real-Time Economic Dispatch of the Real-Time Market runs every five (5) minutes during which the SCED produces binding Dispatch Instructions for the immediately subsequent five-minute interval. For the applicable five-minute time period, through its SCED, the CAISO produces LMPs at each PNode that are used for Settlements as described in Section 11.5.

**27.4.3 CAISO Markets Scheduling and Pricing Parameters**

**27.4.3.1 Generally**

The SCUC and SCED optimization software for the CAISO Markets utilize a set of configurable scheduling and pricing parameters to enable the software to reach a feasible solution and set appropriate prices in instances where Effective Economic Bids are not sufficient to allow a feasible solution. The scheduling parameters specify the criteria for the software to adjust Non-priced Quantities when such adjustment is necessary to reach a feasible solution. The scheduling parameters are configured so that the SCUC and SCED software will utilize Effective Economic Bids as far as possible to reach a feasible solution, and will skip Ineffective Economic Bids and perform adjustments to Non-priced Quantities pursuant to the scheduling priorities for Self-Schedules specified in Sections 31.4 and 34.12. The scheduling parameters utilized for relaxation of enforced internal and Intertie Transmission Constraints are specified in Section 27.4.3.2.1 and 27.4.3.3.1. The pricing parameters specify the criteria for establishing market prices in instances where one or more Non-priced Quantities are adjusted by the Market Clearing software. The pricing parameters are specified in Sections 27.4.3.2.2, 27.4.3.2.3, 27.4.3.2.4, 27.4.3.3.2, 27.4.3.3.3, and 27.4.3.3.4. The complete set of scheduling and pricing parameters used in all CAISO Markets is maintained in the Business Practice Manuals.

**27.4.3.2 Parameters Related to Soft Energy Bid Cap**

For CAISO Market intervals for which the conditions specified in Section 27.4.3.3 do not apply, the CAISO will apply the parameters specified in Sections 27.4.3.2.1 through 27.4.3.2.4, 31.4, 34.12, and the Ancillary Services Scarcity Prices in Section 27.1.2.3.5.

**27.4.3.2.1 Scheduling Parameters for Transmission Constraint Relaxation**

Scheduling parameters, or penalty prices, are used to determine when the SCUC and SCED software will relax an enforced Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $5,000 per MWh. The corresponding scheduling parameter in RUC is set to $1,250 per MWh for internal Transmission Constraints and $3,200 for Intertie Transmission Constraints. In the RTM, this scheduling parameter is set to $1,500 per MWh for internal Transmission Constraints and $2,900 MWh for Intertie Transmission Constraints. The effect of this scheduling parameter is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint or below the applicable price per MWh, the Market Clearing software will utilize such re-dispatch; but if the cost exceeds the applicable price per MWh, the market software will relax the Transmission Constraint.

**27.4.3.2.2 Pricing Parameters for Transmission Constraint Relaxation**

For the purpose of determining how the relaxation of a Transmission Constraint will affect the determination of prices in the IFM and RTM, the pricing parameter of the Transmission Constraint being relaxed is set to the Soft Energy Bid Cap. In the case of Contingency-related Transmission Constraints, the CAISO will determine the amount of relaxation required to clear the market using the most limiting condition among the applicable Contingencies and the base case. The CAISO will establish prices based on the parameter pricing specified in this Section as it applies to the most limiting Contingency and base case. The corresponding pricing parameter used in the RUC is set at the maximum RUC Availability Bid price specified in Section 39.6.1.2.

**27.4.3.2.3 Insufficient Supply to Meet Self-Schedule Demand in IFM**

In the IFM, when available supply is insufficient to meet all self-scheduled Demand, self-scheduled Demand is reduced to the point where the available supply is sufficient to clear the market. For price-setting purposes in such cases, the cleared self-scheduled Demand is deemed to be willing to pay the Soft Energy Bid Cap price.

**27.4.3.2.4 Insufficient Supply to Meet CAISO Forecast of CAISO Demand in the RTM**

In the RTM, in the event that Energy offers are insufficient to meet the CAISO Forecast of CAISO Demand, the SCUC and SCED software will relax the system energy-balance constraint. In such cases the software utilizes a pricing parameter set to the Soft Energy Bid Cap for price-setting purposes.

**27.4.3.3 Parameters Related to Hard Energy Bid Cap**

(a) **Integrated Forward Market and Real-Time Market.** The scheduling and pricing parameters in Sections 27.4.3.3.1 through 27.4.3.3.4, 31.4, and 34.12 will apply for all Trading Hours of the IFM and Real-Time Market for the same Trading Day if the CAISO has accepted a Bid with an Energy Bid price that exceeds the Soft Energy Bid Cap pursuant to Section 30.7.12, or the Maximum Import Bid Price exceeds the Soft Energy Bid Cap for any Trading Hour of the IFM.

(b) **Real-Time Market Only.** If the CAISO has not accepted a Bid with an Energy Bid price that exceeds the Soft Energy Bid Cap pursuant to Section 30.7.12, or the Maximum Import Bid Price does not exceed the Soft Energy Bid Cap for any Trading Hour of the IFM for the same Trading Day, the parameters in Sections 27.4.3.3.1 through 27.4.3.3.4, 31.4, and 34.12 will apply

(i) in any Trading Hour of the Real-Time Market for which the CAISO has accepted a Bid with an Energy Bid price that exceeds the Soft Energy Bid Cap pursuant to Section 30.7.12, or the Maximum Import Bid Price exceeds the Soft Energy Bid Cap; and

(ii) for all intervals of the applicable Real-Time Market run for which these conditions apply in at least one interval of the applicable market run.

**27.4.3.3.1 Scheduling Parameters for Transmission Constraint Relaxation**

Scheduling parameters or penalty prices, are used to determine when the SCUC and SCED software will relax an enforced Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. In the IFM, the enforced internal and Intertie Transmission Constraint scheduling parameter is set to $10,000 per MWh. The corresponding scheduling parameter in RUC is set to $1,250 for internal Transmission Constraints and $3,200 for Intertie Transmission Constraints. In the RTM, this scheduling parameter is set to $3,000 per MWh for internal Transmission Constraints and $5,800 for Intertie Transmission Constraints. The effect of this scheduling parameter is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at or below the applicable price per MWh, the Market Clearing software will utilize such re-dispatch; but if the cost exceeds the applicable price per MWh, the market software will relax the Transmission Constraint.

**27.4.3.3.2 Pricing Parameters for Transmission Constraint Relaxation**

In the case of Contingency-related Transmission Constraints, the CAISO will determine the amount of relaxation required to clear the market using the most limiting condition among the applicable Contingencies and the base case. The CAISO will establish prices based on the parameter pricing specified in this Section as it applies to the most limiting Contingency and base case. The corresponding pricing parameter used in the RUC is set at the maximum RUC Availability Bid price specified in Section 39.6.1.2.

**27.4.3.3.3 Insufficient Supply to Meet Self-Schedule Demand in IFM**

In the IFM, when available supply is insufficient to meet all self-scheduled Demand, self-scheduled Demand is reduced to the point where the available supply is sufficient to clear the market. For price-setting purposes in such cases, the cleared self-scheduled Demand is deemed to be willing to pay the Hard Energy Bid Cap price.

**27.4.3.3.4 Insufficient Supply to Meet CAISO Forecast of CAISO Demand in the RTM**

In the RTM, in the event that Energy offers are insufficient to meet the CAISO Forecast of CAISO Demand, the SCUC and SCED software will relax the system energy-balance constraint. In such cases, for price-setting purposes the software utilizes a pricing parameter set to

(a) the highest-priced cleared Economic Bid if the infeasibility detected in the scheduling run does not exceed the Constraint Relaxation Threshold, but no less than the Soft Energy Bid Cap price; or

(b) the Hard Energy Bid Cap price if the infeasibility detected in the scheduling run exceeds the Constraint Relaxation Threshold.

**27.4.3.4 Protection of TOR, ETC and Converted Rights Self-Schedules in the IFM**

In accordance with the submitted and accepted TRTC Instructions, valid Day-Ahead TOR Self-Schedules, Day-Ahead ETC Self-Schedules and Day-Ahead Converted Rights Self-Schedules shall not be adjusted in the IFM in response to an insufficiency of Effective Economic Bids. The scheduling parameters associated with the TOR, ETC, or Converted Rights Self-Schedules will be set to values higher than the scheduling parameter associated with relaxation of an enforced internal and Intertie Transmission Constraint as specified in Section 27.4.3.2, so that when there is a congested Transmission Constraint that would otherwise subject a Supply or Demand resource submitted in a valid and balanced ETC, TOR or Converted Rights Self-Schedule to adjustment in the IFM, the IFM software will relax the Transmission Constraint rather than curtail the TOR or ETC Self-Schedule. This priority will be adhered to by the operation of the IFM Market Clearing software, and if necessary, by adjustment of Schedules after the IFM has been executed and the results have been reviewed by the CAISO operators.

**27.4.3.5 Effectiveness Threshold**

The CAISO Markets software includes a lower effectiveness threshold setting that governs whether the software will consider a bid “effective” for managing congestion on a congested Transmission Constraint, which in the case of Nomograms will be applied to the individual flowgates that make up the Nomogram, rather than to the Nomogram itself. The CAISO sets this threshold at two-tenths of a percent (.2%) divided by any applicable Deployment Factor for Trading Hubs; Default LAPs; and Interties with significant Total Transfer Capability, as specified in the Business Practice Manual. The CAISO sets the threshold at two percent (2%) divided by any applicable Deployment Factor for all other Nodes.

**27.5 Full Network Model**

**27.5.1 Network Models used in CAISO Markets**

The FNM is a representation of the WECC network model including the CAISO Balancing Authority Area that enables the CAISO to produce a Base Market Model that the CAISO then uses as the basis for formulating the individual market models used to conduct power flow analyses to manage Transmission Constraints for the optimization of each of the CAISO Markets.

**27.5.1.1 Base Market Model used in the CAISO Markets**

Based on the FNM the CAISO creates the Base Market Model, which is used as the basis for formulating, as described in section 27.5.6, the individual market models used in each of the CAISO Markets to establish, enforce, and manage the enforced internal and Intertie Transmission Constraints associated with network facilities. The Base Market Model is derived from the FNM by (1) introducing locations for modeling Intertie Schedules; and (2) introducing market resources that do not currently exist in the FNM due to their size and lack of visibility. In the Base Market Model, external Balancing Authority Areas and external transmission systems are modeled to the extent necessary to 1) improve the accuracy of the CAISO Market solutions for purposes of reliable operations, and 2) support the commercial requirements of the CAISO Markets. For those portions of the FNM that are external to the CAISO Balancing Authority Area, the Base Market Model may model the resistive component for accurate modeling of Transmission Losses, but accounts for losses in the external portions of the market model separately from Transmission Losses within the CAISO Balancing Authority Area. As a result, the Marginal Cost of Losses in the LMPs is not affected by external losses. For portions of the Base Market Model that are external to the CAISO Balancing Authority Area, the CAISO Markets only enforce Transmission Constraints that reflect limitations of the transmission facilities and Entitlements turned over to the Operational Control of the CAISO by a Participating Transmission Owner, or that affect Congestion Management within the CAISO Balancing Authority Area or on Interties. External connections are retained between Intertie branches within Transmission Interfaces. Certain external loops are modeled, which allows the CAISO to increase the accuracy of the Congestion Management process. The CAISO Markets’ optimizations also factor in forecasted unscheduled flow at the Interties consistent with the requirements specified in the Business Practice Manuals. Resources are modeled at the appropriate network Nodes.

The pricing Location (PNode) of a Generating Unit generally coincides with the Node where the relevant revenue quality meter is connected or corrected, to reflect the point at which the Generating Unit is connected to the CAISO Controlled Grid. The Dispatch, Schedule, and LMP of a Generating Unit refers to a PNode, but the Energy injection is modeled in the Base Market Model for network analysis purposes at the corresponding Generating Unit’s physical interconnection point), taking into account any losses in the non-CAISO Controlled Grid leading to the point where Energy is delivered to CAISO Controlled Grid. Based on the Base Market Model, the market models used in each of the CAISO Markets incorporate physical characteristics needed for determining Transmission Losses and model Transmission Constraints within the CAISO Balancing Authority Area, which are then reflected in the Day-Ahead Schedules, AS Awards and RUC Awards, FMM Schedules, Dispatch Instructions, and LMPs resulting from each CAISO Markets Process. The Dispatch, Schedule, and LMP of a Dynamic System Resource or Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area refer to a PNode, or Aggregated Pricing Node, if applicable, of the resource at its physical location in the external transmission systems that are modeled in the Base Market Model, subject to the modeling of Transmission Losses in the portions of the FNM and exclusion of such Transmission Losses’ effects on the LMPs that are external to the CAISO Balancing Authority Area described in this Section 27.5.1.1. The LMP price thus associated with a Dynamic System Resource or Pseudo-Tie Generating Unit will be used for Settlement of Energy and will include the Marginal Cost of Congestion and Marginal Cost of Losses components of the LMP to that Dynamic System Resource or Pseudo-Tie Generating Unit point, excluding losses and congestion external to the CAISO Balancing Authority Area, in accordance with this Section 27.5.1.1. Further, in formulating the market models for the CAISO Market processes, except for specific Intertie locations as specified in the BPM, power flow parameters developed from applicable data sources, including available outage information, system status data, and the State Estimator for the Real-Time Dispatch, are applied to the Base Market Model.

**27.5.1.2 [Not Used]**

**27.5.1.2.1 [Not Used]**

**27.5.1.2.2 [Not Used]**

**27.5.1.2.3 [Not Used]**

**27.5.2 Metered Subsystems**

The FNM includes a full model of MSS transmission networks used for power flow calculations and Congestion Management in the CAISO Markets Processes. Transmission Constraints (i.e. circuit ratings, thermal ratings, etc.) within the MSS, or at its boundaries, that are modeled in the Base Market Model shall be monitored but not enforced in operation of the CAISO Markets. If overloads are observed in the forward markets, are internal to the MSS or at the MSS boundaries, and are attributable to MSS operations, the CAISO shall communicate such events to the Scheduling Coordinator for the MSS and coordinate any manual Re-dispatch required in Real-Time. If, independent of the CAISO, the Scheduling Coordinator for the MSS is unable to resolve Congestion internal to the MSS or at the MSS boundaries in Real-Time, the CAISO will use Exceptional Dispatch Instructions on resources that have been bid into the RTM to resolve the Congestion. The costs of such Exceptional Dispatch will be allocated to the responsible MSS Operator. Consistent with Section 4.9, the CAISO and MSS Operator shall develop specific procedures for each MSS to determine how Transmission Constraints will be handled.

**27.5.3 Integrated Balancing Authority Areas**

To the extent sufficient data are available or adequate estimates can be made for an IBAA, the Base Market Model used by the CAISO for the CAISO Markets Processes will include a model of the IBAA’s network topology. The CAISO monitors but does not enforce the Transmission Constraints for an IBAA in running the CAISO Markets Processes. Similarly, the CAISO models the resistive component for transmission losses on an IBAA but does not allow such losses to determine LMPs that apply for pricing transactions to and from an IBAA and the CAISO Balancing Authority Area, unless allowed under a Market Efficiency Enhancement Agreement. For Bids and Schedules between the CAISO Balancing Authority Area and the IBAA, the CAISO will model the associated sources and sinks that are external to the CAISO Balancing Authority Area using individual or aggregated injections and withdrawals at locations in the FNM that allow the impact of such injections and withdrawals on the CAISO Balancing Authority Area to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO.

**27.5.3.1 Currently Established Integrated Balancing Authority Areas**

The FNM includes the established IBAAs listed below. Additional details regarding the modeling specifications for these IBAAs are provided in the Business Practice Manuals.

(1) The Sacramento Municipal Utility District (SMUD) IBAA including the transmission facilities of the following entities:

(a) Western Area Power Administration – Sierra Nevada Region

(b) Modesto Irrigation District

(c) City of Redding

(d) City of Roseville

(2) Turlock Irrigation District IBAA

**27.5.3.2 Information Required to Develop and Obtain Pricing under a Market Efficiency Enhancement Agreement**

The CAISO shall enter into an MEEA with an entity controlling supply resources within an IBAA to provide modeling and pricing for imports or exports between the IBAA and the CAISO Balancing Authority Area if the entity agrees to provide the information as specified herein. These information requirements apply to all entities seeking to enter into and having entered into an MEEA, including external Balancing Authorities within the IBAA or sub-entities therein such as Scheduling Coordinators or sub-Balancing Authority Areas in control of specific resources or a portfolio of resources. For these purposes, the term resource includes sources or sinks within the IBAA. An MEEA signatory may use generation as a resource to support an import to the CAISO and may use load or reduce generation to support an export from the CAISO. Control includes ownership or any contractual arrangements that provide authority to schedule and/or receive the financial benefits of a resource. Entities controlling a portfolio of resources within the IBAA are eligible to enter into MEEAs for interchange transactions using portfolios of resources. For the purposes of this provision, Western Area Power Administration base resource customers have sufficient control over Western Area Power Administration base resource portfolio of resources within the IBAA to be eligible to enter into MEEAs for interchange transactions utilizing these resources.

In order to obtain non-default, location-specific pricing for interchange transactions with the CAISO Balancing Authority Area, an MEEA signatory must provide the information described in this section 27.5.3.2. The information is necessary to: (i) establish the location of the resources that will be used to calculate location-specific prices under the MEEA, (ii) verify that the resources operating to implement an interchange transaction are the same as the resources identified in the MEEA, (iii) verify the amount of an interchange transaction that was implemented by the dispatch of resources identified in the MEEA, and (iv) settle all charges and payments for interchange transactions under the MEEA.

Subject to the requirements in Section 27.5.3.2.2, the CAISO will provide an LMP to an MEEA signatory for an interchange transaction between the CAISO Balancing Authority Area and the IBAA at the Scheduling Point at which the actual Import or Export Bid is submitted to the CAISO Markets. This MEEA-specific LMP for MEEA transactions shall be calculated for each such Scheduling Point and reflect the nodes where the specific import or export is demonstrated in the MEEA to actually be located. The CAISO will develop generation distribution factors that apply to the relevant MEEA transactions as provided in Section 27.5.3.2.1. The CAISO and an MEEA signatory may negotiate an alternative to the historical average distribution generation factors of MEEA resources, if an MEEA signatory establishes that a different structure more accurately identifies the actual location of resources within the IBAA that support interchange transactions with the CAISO.

**27.5.3.2.1 Information Required to Develop a Market Efficiency Enhancement Agreement**

An entity seeking to enter into an MEEA with the CAISO will provide the CAISO with historical hourly metered generation data for the supply resources to be identified in the MEEA and the historical hourly metered load data within the IBAA for the load served by the MEEA signatory, if any. The data shall be provided in a format that the WECC accepts or other commonly used format. MEEA pricing will typically be based on historical average distribution of generation among a portfolio of resources identified in an MEEA, using negotiated generation distribution factors, subject to revision to reflect changes in usage. The CAISO and an MEEA signatory may, therefore, agree on a set of weighted distribution factors for a specified set of resource locations, which will be used to calculate the MEEA price that will apply to Bids, including Self-Schedules, cleared and processed as further provided in the CAISO Tariff, submitted for resources identified in an MEEA. By applying a set of weighted distribution factors to a set of generator locations, an MEEA signatory is not required to associate a specific generator within a MEEA portfolio of resources with a specific customer of the MEEA signatory. The CAISO will negotiate any generation distribution factors as provided below. For portfolios of resources, the CAISO and a potential MEEA signatory will develop a weighted average price methodology based upon an agreed set of weights for the resources that comprise the MEEA portfolio. Such weights will be based on historical data of operation of the resources comprising the portfolio.

The distribution factors may reflect seasonal, peak and off-peak or other usage and may be periodically revised through bilateral negotiations using updated historical operation data of the MEEA portfolio. All executed MEEAs between the CAISO and an entity with resources within the IBAA must include:

(a) a list of the external supply resources and loads within the IBAA over which the MEEA signatory has control or serves (for these purposes control includes ownership or any contractual arrangements that provide authority to schedule and/or receive the financial benefits of a resources);

(b) the location of the resource identified in the MEEA for which non-default LMP’s will be calculated;

(c) the injection and withdrawal points for the resources identified in the MEEA; and

(d) the appropriate Resource IDs that apply for the MEEA transactions.

**27.5.3.2.2 Information Needed to Determine Application of MEEA Specific Pricing in any Settlement Interval or Settlement Period**

If an MEEA signatory submits a Bid in the CAISO Market and seeks to obtain an MEEA-specific LMP for an interchange transaction, the CAISO must be capable of verifying what portion (output in MWh) of the resources identified in the MEEA, if any, were dispatched to implement the interchange transaction. To the extent that the resources identified in the MEEA, or portion thereof, were dispatched and operated for purposes other than the interchange transaction submitted in the CAISO Market, the Schedule or Imbalance Energy associated with the Bid submitted and cleared in the CAISO Market will not receive an MEEA-specific LMP, and will instead receive the default IBAA price specified in Appendix C, Section I.1.1. The CAISO will establish Resource IDs that are to be used only to submit Bids, including Self-Schedules, for the purpose of obtaining MEEA-specific pricing. MEEA signatories may obtain and use other Resource IDs to submit Bids, including Self-Schedules, that are not covered by an MEEA. Prior to obtaining and settling Resource IDs under the terms of the MEEA, the relevant Scheduling Coordinator shall attest that use of the Resource ID shall mean that the MEEA signatory dispatched a resource identified in an MEEA to support the MEEA interchange transaction. This attestation shall be executed under oath by an officer of the MEEA with knowledge of the MEEA signatory’s operations. By actually using such Resource IDs, the Scheduling Coordinator represents that MEEA resources are dispatched to support such Bids, including Self-Schedules. The CAISO may challenge the use of these Resource IDs and conduct an audit under Section 27.5.3.7.

In connection with any such audit, the MEEA signatory shall support its certification with information demonstrating that an MEEA signatory resource was dispatched to support the interchange transaction. This information may include, but is not limited to, NERC tags, OASIS transmission service data, day-ahead load and resource plans, power purchase agreements or contracts demonstrating use of the California Oregon Transmission Project as well as marginal cost information. An MEEA signatory, however, is not required to provide marginal cost information to the CAISO to support its self-certification and may support its self-certification with other information, including information identified in the preceding sentence. The MEEA signatory shall provide data in a format that the WECC accepts or other commonly used format. For any Settlement Interval or Period for which the CAISO challenges the use of Resource IDs under an MEEA, the CAISO shall apply MEEA pricing to the Settlement Interval or Period pending resolution of the challenge.

In addition, in the event that there is a Dynamic Resource-Specific System Resource in the IBAA, the MEEA may further provide that the MEEA signatory in control of such resource may also obtain pricing under the MEEA for imports to the CAISO Balancing Authority Area from the Dynamic Resource-Specific System Resource. For any portion of an interchange transaction for which the MEEA Entity has not self-certified that the resources were used to support interchange transactions, the default IBAA price specified in Appendix C, Section I.1.1 will apply for the corresponding volume and time period.

**27.5.3.3 Process for Establishing a Market Efficiency Enhancement Agreement**

Any entity seeking to negotiate an MEEA with the CAISO may submit a written request to the CAISO. The CAISO and the requesting entity shall negotiate in good faith the terms and conditions of the MEEA. The CAISO shall file any executed MEEA with FERC for review and approval under Section 205 of the Federal Power Act. In the event an MEEA is not executed within 180 days of the initial written request for an MEEA, a requesting entity may invoke the CAISO ADR Procedures under Section 13.

**27.5.3.4 Use of Data Provided under a Market Efficiency Enhancement Agreement**

Data provided to the CAISO pursuant to an MEEA shall be used for purposes of modeling and pricing Interchange transactions between the CAISO Balancing Authority Area and the relevant IBAA at Scheduling Points specified in the MEEA. The configuration of the pricing points for the MEEA, which may include specific distribution factors for the represented resources, established through the negotiation of the MEEA will also be used for the purposes of modeling the resources in the IBAA subject to the MEEA. The CAISO and the MEEA signatory may agree to changes to these configurations over time that do not require the renegotiation of the terms of the MEEA or may agree to static terms until such time the parties re-execute a new MEEA. Such modeling information regarding the location of the resources will be incorporated into the Full Network Model, including the CRR FNM, which is used for all CAISO Markets as further described in Sections 27.3, 27.5.1 and 27.5.6. The FNM and the CRR FNM will not include the hourly transactional data provided pursuant to Section 27.5.3.2, except in such cases where the CAISO and the MEEA signatory have agreed to dynamic changes to the configuration of the modeling of the MEEA resources during the life of the agreement as further provided by the MEEA.

**27.5.3.5 Measures to Preserve Confidentiality of Data under a Market Efficiency Enhancement Agreement**

Subject to the provisions of Section 27.5.3.4, data provided to the CAISO by any entity under an MEEA or in connection with negotiations to develop an MEEA shall be treated as confidential data. Consistent with applicable law, the CAISO shall take all steps reasonably necessary to limit disclosure of this information to CAISO personnel that need to review such information as part of their work-related responsibilities. In the event a disclosing entity does not execute an MEEA, the CAISO shall return the confidential data to the disclosing entity if the CAISO can physically return the data and shall destroy the confidential data if the CAISO cannot physically return the confidential data to the disclosing entity.

**27.5.3.6 Dispute Resolution under Market Efficiency Enhancement Agreements**

Any disputes arising out of or in connection with an MEEA shall be subject to the CAISO ADR Procedures of Section 13.

**27.5.3.7 Audit Rights under Market Enhancement Efficiency Agreement**

The CAISO reserves the right to audit data supplied under an MEEA by giving written notice at least ten (10) Business Days in advance of the date that the CAISO wishes to initiate such audit, with completion of the audit occurring within 180 days of such notice. The audit shall be for the limited purposes of verifying that the MEEA signatory has accurately represented available resources and has met the requirements specified for MEEA pricing. Upon request of the CAISO as part of such audit, any signatory to an MEEA shall provide information to support its certification under Section 27.5.3.2. An MEEA signatory may audit the price for any transaction entered into under an MEEA through the CAISO’s Settlement and billing process set forth in Section 11 and through data provided to the MEEA signatory as a Market Participant under the CAISO Tariff. Each party will be responsible for its own expenses related to any audit.

**27.5.3.8 Process for Establishing a New IBAA or Modifying an Existing IBAA**

Except under exigent circumstances, the CAISO must follow a consultative process with the applicable Balancing Authority and CAISO Market Participants pursuant to the process further defined in the Business Practice Manuals, to establish a new IBAA or modify an existing IBAA. Changes to an existing IBAA may include among others changes to the modeling of the IBAA’s network topology, the specification of the default Resource IDs or the default pricing points. Upon completion of this process and having determined it necessary to establish a new IBAA or modify an existing IBAA, the CAISO will seek FERC approval under Section 205 of the Federal Power Act of the proposed new IBAA or changes to the existing IBAA requirements, at which time the CAISO shall also provide its supportive findings for the establishment of the new IBAA or modification to an existing IBAA.

**27.5.3.8.1 Factors to be Considered in Establishing a New Integrated Balancing Authority Area or Modifying an Existing Integrated Balancing Authority Area**

In establishing a new IBAA or modifying an existing IBAA, the factors that the CAISO will consider shall include, but are not limited to, the following:

(1) The number of Interties between the potential or existing IBAA and the CAISO Balancing Authority Area and the distance between them;

(2) Whether the transmission system(s) within the other Balancing Authority Area runs in parallel to major parts of the CAISO Controlled Grid;

(3) The frequency and magnitude of unscheduled power flows at applicable Interties;

(4) The number of hours where the actual direction of power flows was reversed from scheduled directions;

(5) The availability of information to the CAISO for modeling accuracy; and

(6) The estimated improvement to the CAISO’s power flow modeling and Congestion Management processes to be achieved through more accurate modeling of the Balancing Authority Area.

**27.5.3.9 Default Designation of External Resource Locations for Modeling Transactions Between the CAISO Balancing Authority Area and an IBAA**

Prior to the establishment of a new IBAA or a change to an existing IBAA, the CAISO will define and publish default Resource IDs to be used for submitting import and export Bids and for settling import and export Schedules between the CAISO Balancing Authority Area and the potential or existing IBAA. These default Resource IDs will specify in the Master File the default associations of Intertie Scheduling Point Bids and Schedules to supporting individual or aggregate injection or withdrawal locations in the FNM. The CAISO will determine the supporting injection and withdrawal locations to allow the impact of the associated Intertie Scheduling Point Bids and Schedules to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO. The CAISO’s methodology for determining such default Resource IDs, as well as the specific default Resource IDs that have been adopted for the currently established IBAAs, are provided in the Business Practice Manuals. Alternative Resource IDs to be used instead of the default Resource IDs will be created and adopted for use in conjunction with Intertie Scheduling Point Bids and Schedules between the CAISO Balancing Authority Area and the IBAA based on a Market Efficiency Enhancement Agreement.

**27.5.4 Accounting for Changes in Topology in IFM**

The CAISO will incorporate into the FNM information received pursuant to Section 24 for transmission expansion and Section 25 for generation interconnection to account for changes to the CAISO Controlled Grid and other facilities located within the CAISO Balancing Authority Area. This information will be incorporated into the network model data base in which the electrical network model is maintained for use by the State Estimator and which forms the basis for the Base Market Model used by the CAISO Markets. The updated power system network model will be transferred at periodic model update cycle intervals established by the CAISO and incorporated into the {Base Market Model} for use in the CAISO Markets. The Business Practice Manual for managing the Full Network Model will describe the information to be provided by Market Participants, the process by which the CAISO incorporates this information in the FNM, and operational details of the FNM. If the CAISO becomes aware of a material error or omission in the FNM, it will make a timely correction of the FNM.

**27.5.5 Load Distribution Factor**

The CAISO will maintain a library of system-wide Load Distribution Factors for use in distributing Demand scheduled at the Default LAPs. The system Load Distribution Factors are derived from the State Estimator and are stored in the Load Distribution Factor library, and are updated periodically. For IFM the Load Distribution Factor library uses a similar-day methodology for smoothing the most recent Load Distribution Factors. The similar-day methodology uses data separately for each type of day. More recent days are weighted more heavily in the smoothing calculations. The market application then uses the set of Load Distribution Factors from the library that best represents the Load distribution conditions expected for use in the CAISO Markets Processes. For the RTM, the State Estimator solution is used as a source for determining Load Distribution Factors. The Load Distribution Factor are also maintained for use for Demand scheduled at Custom LAPs. These custom Load Distribution Factors are not generated from the State Estimator and are fixed quantities representing the characteristics of the Custom LAP.

**27.5.6 Management & Enforcement of Constraints in the CAISO Markets**

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, Transmission Constraints, and transmission and generation Outages, including due to Remedial Action Schemes. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market and each process of the Real-Time Market. The CAISO will manage the enforcement of Transmission Constraints, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

(a) The CAISO may enforce, not enforce, or adjust flow-based Transmission Constraints if the CAISO observes that the CAISO Markets produce or may produce results that are inconsistent with observed or reasonably anticipated conditions or infeasible market solutions either because (a) the CAISO reasonably anticipates that the CAISO Market run will identify Congestion that is unlikely to materialize in Real-Time even if the Transmission Constraint were to be ignored in all the markets leading to Real-Time, or (b) the CAISO reasonably anticipates that the CAISO Market will fail to identify Congestion that is likely to appear in the Real-Time. The CAISO does not make such adjustments to intertie Scheduling Limits.

(b) The CAISO may enforce or not enforce Transmission Constraints if the CAISO has determined that non-enforcement or enforcement, respectively, of such Transmission Constraints may result in the unnecessary pre-commitment and scheduling of use-limited resources.

(c) The CAISO may not enforce Transmission Constraints if it has determined it lacks sufficient visibility to conditions on transmission facilities necessary to reliably ascertain constraint flows required for a feasible, accurate and reliable market solution.

(d) For the duration of a planned or unplanned Outage, the CAISO may create and apply alternative Transmission Constraints that may add to or replace certain originally defined constraints.

(e) The CAISO may adjust Transmission Constraints for the purpose of setting prudent operating margins consistent with good utility practice to ensure reliable operation under anticipated conditions of unpredictable and uncontrollable flow volatility consistent with the requirements of Section 7.

(f) The CAISO may adjust Transmission Constraints for the purpose of reserving internal transfer capability in the Day-Ahead or Real-Time Markets, based on anticipated conditions on the natural gas delivery system, to reliably serve load in specific geographic regions of the CAISO Balancing Authority Area, or to assure deliverability of Ancillary Services. The CAISO may or may not release such reserved internal transfer capability based on natural gas and electric system conditions, or observed market inefficiencies. Upon determining that an adjustment is necessary, the CAISO will issue a notification specifying the amount of the adjustment.

To the extent that particular Transmission Constraints are not enforced in the operations of the CAISO Markets, the CAISO will operate the CAISO Controlled Grid and manage any Congestion based on available information including the State Estimator solutions and available telemetry to Dispatch resources through Exceptional Dispatch to ensure the CAISO is operating the CAISO Controlled Grid consistent with the requirements of Section 7.

**27.6 State Estimator**

The State Estimator produces a power flow solution based upon the modeled representation of the electrical network and available Real-Time SCADA telemetry. When this solution is applied to the FNM, it provides a reference of system conditions for determining Dispatch Instructions. The State Estimator also provides a reference for Real-Time Load Distribution Factors used to distribute the Real-Time CAISO Forecast of CAISO Demand as well as provide a source of historical data for the LDF library. If the State Estimator is not capable of providing CAISO with a solution to clear the CAISO Markets, the CAISO shall use the last best State Estimator solution for determining Dispatch Instructions, provided the State Estimator is not unavailable for an extended period. If the State Estimator is not available for an extended period of time, the CAISO shall use the Load Distribution Factors from the Load Distribution Factors library as applicable to the prevailing system and time of use conditions to determine Dispatch Instructions.

**27.7 Constrained Output Generation**

**27.7.1 Election of Constrained Output Generator Status**

A Scheduling Coordinator on behalf of a Generating Unit eligible for COG status must make an election to have the resource treated as a COG before each calendar year by registering the resource’s PMin in the Master File as equal to its PMax less 0.01 MW (PMin = PMax – 0.01 MW) within the timing requirements specified for Master File changes described in the applicable Business Practice Manual. Generating Units with COG status will be eligible to set LMPs in the IFM and RTM based on their Calculated Energy Bids.

As with all Generating Units that are not Use-Limited Resources, a Scheduling Coordinator on behalf of a COG that is not a Use-Limited Resource must use the Proxy Cost methodology, as provided in Section 30.4, for determining its Default Start-Up Bids and Default Minimum Load Bids. A Scheduling Coordinator on behalf of a COG that is a Use-Limited Resource must elect to use either the Proxy Cost methodology or the Registered Cost methodology, as provided in Section 30.4, for determining its Default Start-Up Bids and Default Minimum Load Bids. A Calculated Energy Bid of a COG that is not a Use-Limited Resource will be calculated based on the Proxy Cost methodology. A Calculated Energy Bid of a COG that is a Use-Limited Resource will be calculated based on its election of the Proxy Cost methodology or the Registered Cost methodology. Whenever a Scheduling Coordinator for a COG submits an Energy Bid into the IFM or RTM, the CAISO will override that Bid and substitute the Calculated Energy Bid if the submitted Bid is different from the Calculated Energy Bid.

**27.7.2 Election to Waive COG Status**

A Scheduling Coordinator on behalf of a Generating Unit eligible for COG status may elect to waive COG status. If such Generating Unit has a non-zero operating range (PMax greater than PMin), it is eligible to participate in the CAISO Markets like any other resource.

**27.7.3 Constrained Output Generators in the IFM**

In the IFM, resources electing COG status are modeled as though they are not constrained and can operate flexibly between zero (0) and their PMax. A COG is eligible to set IFM LMPs based on its Calculated Energy Bid in any Settlement Period in which a portion of its output is needed as a flexible resource to serve Demand. A COG is not eligible for recovery of Minimum Load Costs or BCR in the IFM due to the conversion of its Minimum Load Cost to an Energy Bid and its treatment by the IFM as a flexible resource. A COG is eligible for Start-Up Bid Cost recovery based on its Commitment Period as determined in the IFM, RUC, STUC or RTUC.

**27.7.4 Constrained Output Generators in RUC**

In RUC, any COG that has capacity that did not fully clear in the IFM is treated as constrained, so that the entire capacity of the COG is committed by RUC. Any such RUC commitment would apply to scheduled capacity in RUC in excess of the higher of: (a) the relevant Day-Ahead Schedule; or (b) the relevant Minimum Load. In the event of a RUC commitment, the COG is not eligible to receive a RUC Award.

**27.7.5 Constrained Output Generators in the Real-Time Market**

A COG that can be started up and complete its Minimum Run Time within a five-hour period can be committed by the STUC. A COG that can be started up within the applicable RTUC run as described in Section 34.3 can be committed by the RTUC. The RTD will dispatch a COG up to its PMax or down to zero (0) to ensure a feasible Real-Time Dispatch. The COG is eligible to set the RTM LMP in any Dispatch Interval in which a portion of its output is needed to serve Demand, not taking into consideration its Minimum Run Time constraint. For the purpose of making this determination and setting the RTM LMP, the CAISO treats a COG as if it were flexible with an infinite Ramp Rate between zero (0) and its PMax, and uses the COG’s Calculated Energy Bid. In any Dispatch Interval where none of the output of a COG is needed as a flexible resource to serve Demand, the CAISO shall not dispatch the unit. In circumstances in which the output of the COG is not needed as a flexible resource to serve Demand, but the unit nonetheless is online as a result of a previous commitment or Dispatch Instruction by the CAISO, the COG is eligible for Minimum Load Bid Cost compensation.

**27.8 Multi-Stage Generating Resources**

**27.8.1 Registration and Qualification**

Scheduling Coordinators responsible for resources that meet the definition of a Multi-Stage Generating Resource based on their Master File registered characteristics must register such resources with the CAISO as Multi-Stage Generating Resources as further discussed in this Section, and must comply with all requirements that apply to such resources specified in the CAISO Tariff. Scheduling Coordinators must comply with the registration and qualification process described in this Section 27.8.1, in order to effectuate any of the changes described in Section 27.8.3. No less than sixteen (16) days prior to the date that Scheduling Coordinator seeks to have the resource participate in the CAISO Markets under the new settings or MSG Configuration details, the Scheduling Coordinator must complete and submit to the CAISO the registration form and the resource data template provided by the CAISO for registration and qualification purposes. After the Scheduling Coordinator submits a request for registration of a Generating Unit as a Multi-Stage Generating Resource or a change in the attributes in Section 27.8.3, the CAISO will coordinate with that Scheduling Coordinator to validate that the resource qualifies for the requested status and that all the requisite information has been successfully provided to the CAISO. The resource will be successfully registered and qualified as a Multi-Stage Generating Resource, or the requested changes in the attributes listed in Section 27.8.3 will be successfully registered and qualified as of the date on which the CAISO sends the responsible Scheduling Coordinator a notice that the resource has been successfully qualified as such. In the absence of extenuating circumstances, the ISO will provide such notice on the sixteenth day after the Scheduling Coordinator provides new settings or MSG Configuration details. After the date on which the CAISO has provided such notice, any changes to the items listed in Section 27.8.3 will be subject to the timing and process requirements in this Section 27.8.1 and 27.8.3. The Scheduling Coordinator may modify all other Multi-Stage Generating Resource registered characteristics pursuant to the timing and processing requirements specified elsewhere in this CAISO Tariff, as they may apply. If the CAISO has reason to believe that the resource’s operating and technical characteristics are not consistent with the registered and qualified attributes, the CAISO may request that the Scheduling Coordinator provide additional information necessary to support their registered status and, if appropriate, may require that the resource be registered and qualified more consistent with the resource’s operating and technical characteristics, including the revocation of its status as a Multi-Stage Generating Resource. Failure to provide such information may be grounds for revocation of Multi-Stage Generating Resource status. Such changes in status or MSG Configuration details would be subject to the registration and qualification requirements in this Section 27.8. Scheduling Coordinators may register the number MSG Configurations as are reasonably appropriate for the resource based on the technical and operating characteristics of the resource, which may not, however, exceed a total of ten MSG Configurations and cannot be fewer than two MSG Configurations. The information requirements specified in Section 27.8.2 will apply.

**27.8.2 Information Requirements**

As part of the registration process described in Section 27.8.1, the Scheduling Coordinators for Generating Units that seek to qualify as Multi-Stage Generating Resources must submit to the CAISO a Transition Matrix, which contains the Transition Costs and operating constraints associated with MSG Transitions. The Scheduling Coordinator may register up to six (6) MSG Configurations without any limitation on the number of transitions between the registered MSG Configurations in the Transition Matrix. If the Scheduling Coordinator registers seven (7) or more MSG Configurations, then the Scheduling Coordinator may only include two (2) eligible transitions between MSG Configurations for upward and downward transitions, respectively, starting from the initial MSG Configuration in the Transition Matrix. For each MSG Configuration, the responsible Scheduling Coordinator shall submit an Operational Ramp Rate and, as applicable, an Operating Reserve Ramp Rate and Regulating Reserves ramp rate, each of which shall have at least one (1) segment and no more than two (2) segments. The Scheduling Coordinator must establish the default MSG Configuration and its associated Default Resource Adequacy Path that apply to Multi-Stage Generating Resources that are subject to Resource Adequacy must-offer obligations. The Scheduling Coordinator may submit changes to this information consistent with Sections 27.8.1 and 27.8.3, as they may apply.

**27.8.3 Changes in Status and Configurations of Resource**

Scheduling Coordinators may seek modifications to the Multi-Stage Generating Resource attributes listed below consistent with the process and timing requirements specified in Section 27.8.1 and the additional requirements discussed below in this Section 27.8.3:

(1) Registration and qualification of a Generating Unit as a Multi-Stage Generating Resource.

(2) Changes to the MSG Configurations attributes, which include:

a. addition of new MSG Configurations;

b. removal of an existing MSG Configuration;

c. a change in the physical units supporting the MSG Configuration;

d. a change to the MSG Configuration Start Up and Shut Down flags;

e. adding or removing an MSG Transition to the Transition Matrix;

f. a material change in the Transition Times contained in the Master File, which consists of a change that more than doubles the Transition Times or reduces it to less than half; and

g. a material change to the maximum Ramp Rate of the MSG Configuration(s) contained in the Master File, which consists of a change that more than doubles the maximum Ramp Rate or reduces it to less than half.

When transitioning to implement these changes across the midnight hour, for any Real-Time Market run in which the changes specified in this Section 27.8.3 are to take effect within the time horizon of any of the Real-Time Market runs, the CAISO will Schedule, Dispatch, or award resources consistent with either the prior or new status and definitions, as appropriate, and required by any Real-Time conditions regardless of the resource’s state scheduled or awarded in the immediately preceding Day-Ahead Market. A Scheduling Coordinator may unregister a Generating Unit from its Multi-Stage Generating Resource status subject to the timing requirements for Master File changes, and such changes are not subject to the timing requirements in Section 27.8.3. Changes to the attributes listed above in this Section may take effect, including the registration of new Multi-Stage Generating Resources, provided Scheduling Coordinators have previously followed the registration process requirements listed in Section 27.8.1. Changes to these attributes may only be made every sixty (60) days after the day on which any such changes have taken effect.

**27.9 Non-Generator Resources and Pumped-Storage Hydro Unit Constraints**

Scheduling Coordinators may elect to provide the CAISO with Non-Generator Resources’ and Pumped-Storage Hydro Units’ MWh constraints. In such cases, the CAISO will observe MWh constraints in the IFM, RUC, Real-Time Unit Commitment, and FMM as part of the co-optimization except for Non-Generator Resources using Regulation Energy Management. The CAISO will observe MWh constraints in Real-Time Dispatch, including constraints of resources using Regulatory Energy Management.

Consistent with Section 4.6.11 and in addition to Master File parameters available to Generating Units, Scheduling Coordinators for Non-Generator Resources with physical operating constraints may include in the Master File:

(a) continuous energy limits: minimum and maximum states of charge in MWh values; and

(b) generation capacity limits: minimum and maximum charge and discharge limits in MW.

Consistent with Section 4.6.11 and in addition to Master File parameters available to Generating Units, Scheduling Coordinators for Pumped-Storage Hydro Units with physical operating constraints may include in the Master File:

(a) generation capacity limits: minimum and maximum pumping and generating limits in MW;

(b) pump minimum up time: minutes a pump must continue pumping;

(c) pump minimum down time: minutes a pump cannot return to pumping after shutting down;

(d) minimum on time: minutes Generating Unit must stay on before shut down or switch to pumping mode;

(e) gen-to-pump minimum down time: minutes after being de-committed from generation mode before able to be dispatched in pumping mode; and

(f) pump-to-gen minimum down time: minutes after being de-committed from pumping mode before able to be dispatched in generation mode.

**27.10 Election to Use Non-Generator Resource Generic Modeling Functionality**

The CAISO employs functionality to model Non-Generator Resources’ participation in the CAISO’s markets. Resource types other than Non-Generator Resources that have a PMax greater than zero may also elect to use this modeling functionality. As further described in the Business Practice Manual and consistent with the CAISO’s Full Network Model database release schedule, Scheduling Coordinators may elect to use Non-Generator Resource Generic Modeling functionality for individual resources or an aggregation of resources. For these resources, the CAISO will not observe costs normally associated with resource management, including but not limited to Start-Up Costs, Minimum Load Costs, or Transition Costs. The CAISO will not observe these resources’ MWh constraints. The CAISO’s market power mitigation processes, including Local Market Power Mitigation, will apply to resources electing to use Non-Generator Resource Generic Modeling functionality consistent with the provisions of Sections 31.2 and 34.1.5 of the CAISO Tariff. If Bids from a particular resource type are not subject to market power mitigation pursuant to the provisions Sections 31.2 and 34.1.5 of the CAISO Tariff, then use of Non-Generator Resource Generic Modeling functionality will not make Bids from the resource subject to market power mitigation. Resources subject to market power mitigation that elect to use Non-Generator Resource Generic Modeling functionality may use any of the methods under the CAISO’s Tariff to establish a Default Energy Bid. Resources electing to use Non-Generator Resource Generic Modeling functionality are not eligible to be Resource Adequacy Resources.

**27.11 Natural Gas Constraint**

The CAISO may enforce constraints that limit the maximum amount of natural gas that can be burned by natural gas-fired resources in the Southern California Gas Company and San Diego Gas & Electric Company gas regions, based on limitations in applicable gas regions anticipated by the CAISO during specific hours. In the event that such a constraint is binding, the Shadow Price of the constraint will be reflected in the Marginal Cost of Congestion component of the Locational Marginal Prices of only the affected natural gas-fired resources. The Shadow Price of the constraint will not be reflected in the Marginal Cost of Congestion component of the Locational Marginal Prices for purposes of settling cleared Demand, Virtual Bids, or Congestion Revenue Rights. The same Marginal Cost of Congestion used for settling Demand, Virtual Bids, or Congestion Revenue Rights is used for the calculation of the Real-Time Congestion Offset pursuant Section 11.5.4.1.1. The CAISO will allocate any non-zero amounts that are attributable to the price differential between the Marginal Cost of Congestion used for settling a Generating Unit’s scheduled or Dispatched amounts at their location and the Marginal Cost of Congestion used for settling Demand, Virtual Bids, or Congestion Revenue Rights pursuant to Section 11.5.4, except that for Day-Ahead settlements the CAISO will allocate the difference through the CRR Balancing Account pursuant to Section 11.2.4.5. The CAISO will provide, through the procedures set forth in Section 6.5.10.1.1, information on whether the CAISO plans to enforce a natural gas constraint in the Day-Ahead Market, and after the Day-Ahead Market is executed, whether it enforced a natural gas constraint in the Day-Ahead Market. In addition, to the extent feasible in advance of the deadline for submitting Bids for the Day-Ahead or Real-Time Market, as applicable, the CAISO will issue a notice through its market notification system indicating its intent to enforce a natural gas constraint along with the affected areas and the magnitude and expected duration of the natural gas constraint.

**27.12 Operator Imbalance Conformance**

**27.12.1 Operator Conformance in the Real-Time Market**

The CAISO Operator may conform the CAISO Forecast of CAISO Demand prior to executing a Real-Time Market run to obtain a Real-Time Market solution that is feasible and accounts for known system conditions for reliable operations. The EIM Entity operator may conform the EIM Demand forecast prior to the CAISO executing a Real-Time Market run to obtain a Real-Time Market solution that is feasible and accounts for known system conditions of the respective EIM Entity’s Balancing Authority Area for reliable operations. System operators conform the CAISO Forecast of CAISO Demand or EIM Demand through an adjustment of the respective forecast. The CAISO or EIM Entity operators will consider factors such as: load forecast discrepancies; Area Control Error adjustments; Variable Energy Resource deviations; resource outages not entered in the Outage Management System; generator testing; reliability curtailments due to transmission or equipment outages; weather changes; and pumping resource schedule changes. The CAISO and the EIM Entity will log Operator conformances.

**27.12.2 Conformance Limiter in the Real-Time Market**

The CAISO will limit an Operator conformance in the Real-time Market to ensure the conformance does not trigger shortage or surplus pricing for any interval in which there is no shortage or surplus of Energy indicated during the pricing of resources for that interval. The conformance limiter logic will: (1) be based on the conformance and ramping capability shortages or surplus changes between intervals; (2) consider information from current and previous intervals; (3) not require that the conformance is the same direction of the shortages or surpluses of ramp capability; and (4) consider the conformance magnitude in previous intervals and whether the limiter was applied in the corresponding intervals.

**27.13 Aggregate Capability Constraint**

At the request of the Interconnection Customer, the CAISO may enforce an Aggregate Capability Constraint for Generating Facilities with Co-located Resources that reflects a Generating Facility’s maximum and minimum capability or a portion of that capability for purposes of Day-Ahead Market Awards, Real-Time Market Awards, and Real-Time Dispatch as described in the CAISO’s Business Practice Manuals. If the combined PMax of Co-located Resources associated with a single Generating Facility would exceed the Interconnection Service Capacity of that Generating Facility, the Interconnection Customer may request that the CAISO enforce an Aggregate Capability Constraint or multiple Aggregate Capability Constraints at the Generating Facility as described in the CAISO’s Business Practice Manuals. If the Interconnection Customer requests that the CAISO enforce multiple Aggregate Capability Constraints, the CAISO will enforce an Aggregate Capability Constraint at the Generating Facility level and subordinate Aggregate Capability Constraints at the level of Resource IDs.

If the Interconnection Customer does not elect an Aggregate Capability Constraint(s), the combined PMax of the Co-located Resources registered in the Master File for that Generating Facility may not exceed the Generating Facility’s Interconnection Service Capacity. EIM Participating Resource Scheduling Coordinators also may request that the CAISO enforce an Aggregate Capability Constraint or multiple Aggregate Capability Constraints for Co-located Resources, subject to the prior written approval of the applicable EIM Entity Balancing Authority that enforcing an Aggregate Capability Constraint(s) for Co-located Resources does not create a threat to safety or reliability.

As described in the CAISO’s Business Practice Manuals the CAISO may relax enforcement of subordinate Aggregate Capability Constraints in its Real-Time Market prior to relaxing enforcement of the system energy-balance constraint specified in Sections 27.4.3.3.4 to ensure there is sufficient Supply to meet the CAISO Forecast of CAISO Demand.

Notwithstanding Section 34.13, a Generating Facility whose Co-located Resources, including Variable Energy Resources, do not comply with Dispatch Instructions such that their output exceeds the Interconnection Service Capacity of the Generating Facility, will be ineligible for the Aggregate Capability Constraint. In such cases, the CAISO will adjust the PMaxes of those Co-located Resources proportionate to each Generating Unit’s capacity such that the sum of the PMax values equals the Interconnection Service Capacity of the Generating Facility, or as requested by the Interconnection Customer so long as the total value does not exceed the Interconnection Service Capacity of the Generating Facility.

Similar to other Generating Facilities with multiple Resource IDs, the CAISO will have no liability with respect to Co-located Resources or their Scheduling Coordinators if Co-located Resources do not comply with Dispatch Instructions and infringe on Interconnection Service Capability used by other Co-located Resources at a Generating Facility.

In the event that Co-located Resources in an EIM Entity Balancing Authority area do not comply with Dispatch Instructions such that their output exceeds the interconnection service capacity for the Co-located Resources, the CAISO will ask the applicable EIM Entity Balancing Authority whether it will revoke its prior approval of enforcing the Aggregate Capability Constraint for such Co-located Resources.

The following resources are not eligible to use the Aggregate Capability Constraint: Multi-Stage Generators, Pseudo-Tie Resources, Proxy Demand Response, Pumped Storage Hydro Units, Metered Subsystems, and Use-Limited Resources.

Scheduling Coordinators may not offer or self-provide Ancillary Services into the CAISO’s Markets or receive Uncertainty Awards from Generating Units that are subject to Aggregate Capability Constraints until the CAISO issues a Market Notice stating this restriction will no longer apply. The Pricing Node for the Generating Units or EIM Participating Resources subject to an Aggregate Capability Constraint will be their Point of Interconnection.

\* \* \*

# 30. Bid and Self-Schedule Submission for all CAISO Markets

## 30.1 Bids, Including Self-Schedules

Scheduling Coordinators shall submit Bids to participate in the CAISO Markets, as well as any Self-Schedules, ETC Self-Schedules, TOR Self-Schedules, or Self-Provided Ancillary Services. Bidding rules for each type of resource are contained in this Section 30 and additional specifications regarding bidding practices are contained in the Business Practice Manuals posted on the CAISO Website. Bids will consist of various components described in this Section 30 through which the Scheduling Coordinator provides information regarding the parameters and conditions pursuant to which the Bid may be optimized by the CAISO Markets.

### 30.1.1 Day-Ahead Market

Bids submitted in the DAM apply to the twenty-four (24) hours of the next Trading Day (23 or 25 hours on the Daylight Savings transition days) and are used in both the IFM and RUC. Bids for the Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve service in the Day-Ahead Market must be received by Market Close for the Day-Ahead Market. The Bids shall include information for each of the twenty-four (24) Settlement Periods of the Trading Day. Failure to provide the information within the stated time frame shall result in the Bids being declared invalid by the CAISO. Scheduling Coordinators may submit Bids for the DAM as early as seven (7) days ahead of the targeted Trading Day.

### 30.1.2 Real-Time Market

Economic Bids and Self-Schedules submitted in the RTM apply to a single Trading Hour and are used for all market processes of the RTM. The CAISO will require Scheduling Coordinators to honor their Day-Ahead Ancillary Services Awards when submitting Ancillary Services Bids in the RTM. Bids for Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve service for each Settlement Period must be received at least seventy-five minutes prior to the commencement of that Settlement Period. The Bids shall include information for only the relevant Settlement Period. Failure to provide the information within the stated timeframe shall result in the Bids being declared invalid and rejected by the CAISO.

## 30.2 Bid Types

There are four types of Bids: Energy Bids (which include Virtual Bids), Ancillary Services Bids, Imbalance Reserves Bids, and RUC Availability Bids. Energy Bids that are not Virtual Bids, and Ancillary Services Bids can be submitted as either an Economic Bid or a Self-Schedule. All other bid types must be submitted as Economic Bids. Economic Bids specify prices for MW amounts of capacity or MWh amounts of Energy. Self-Schedules do not have any prices associated for MW or MWh. Energy Bids, including both Economic Bids and Self-Schedules (where Self-Schedules are otherwise permitted), may be either Supply Bids, Demand Bids, Virtual Supply Bids, or Virtual Demand Bids. Ancillary Services Bids, RUC Availability Bids, and Imbalance Reserves Bids are Supply Bids only. Ancillary Services may be self-provided by providing a Submission to Self-Provide an Ancillary Service and having that submission accepted by the CAISO. Rules for submitting the four types of Bids vary by the type of resource to which the Bid applies as described in Section 30.5 and as further required in each CAISO Markets process as specified in Sections 31, 33, and 34.

## 30.3 [Not Used]

## 30.4 Default Start-Up Bids, Default Minimum Load Bids, and Default Transition Bids

### 30.4.1 Generally

The CAISO will calculate Default Commitment Cost Bids using the Proxy Cost methodology for all resources, except for:

(a) Non-Resource-Specific Resources and Non-Generating Resources; or

(b) a resource that is qualified by the CAISO as a Use-Limited Resource and the resource has fewer than twelve (12) consecutive months of fifteen-minute LMPs for Energy at the resource’s PNode or Aggregated PNode, in which case the resource’s Default Commitment Cost Bids will be determined as Registered Costs under the Registered Cost methodology pursuant to Section 30.4.7.

### 30.4.2 Transition of Use-Limited Resources to Proxy Costs

Scheduling Coordinators on behalf of Use-Limited Resources with fewer than 12 months of data can elect to use the Registered Cost methodology and remain on that methodology for a two-month period once 12 months of pricing data is collected, while the Scheduling Coordinator and the CAISO are going through the process of determining what Opportunity Costs, if any, apply to the Use-Limited Resource. Once this process concludes, all such Use-Limited Resources must be subject to the Proxy Cost methodology.

For Use-Limited Resources eligible for the Registered Cost methodology, Scheduling Coordinators may elect on a thirty (30) day basis to use either the Proxy Cost methodology or the Registered Cost methodology for calculating their Default Start-Up Bids and Default Minimum Load Bids to be used for those resources in the CAISO Markets Processes, as well as for Default Transition Bids in the case of Multi-Stage Generating Resources. The elections are independent as to Default Start-Up Bids and Default Minimum Load Bids; that is, a Scheduling Coordinator for such a Use-Limited Resource may elect to use either the Proxy Cost methodology or the Registered Cost methodology for Default Start-Up Bids and may make a different election for Default Minimum Load Bids. However, in the case of Multi-Stage Generating Resources, the Scheduling Coordinator must make the same election (Proxy Cost methodology or Registered Cost methodology) for Default Transition Bids as it makes for Default Start-Up Bids. If a Scheduling Coordinator has not made an election, the CAISO will assume the Proxy Cost methodology as the default.

### 30.4.3 Scheduling Coordinator Reference Level Change Requests

The CAISO will verify Reference Level Change Requests for changes to Default Start-Up Bids and Default Minimum Load Bids as described in Section 30.11.

### 30.4.4 Default Commitment Cost Bids

**30.4.4.1 Using Proxy Cost Methodology**

For resources under the Proxy Cost methodology, the CAISO will calculate a resource’s Default Commitment Cost Bids as the applicable Proxy Cost multiplied by the Commitment Cost Multiplier.

**30.4.4.2 Use-Limited Resources**

For Use-Limited Resources using the Proxy Cost methodology, the CAISO will calculate a resource’s Default Commitment Cost Bids as the applicable Proxy Cost multiplied by Commitment Cost Multiplier plus the Start-Up Opportunity Cost, Transition Opportunity Cost, or Minimum Load Opportunity Cost as applicable.

**30.4.4.3 Registered Costs**

For Use-Limited Resources using the Registered Cost methodology, the CAISO will use the Registered Costs as registered in the Master File as the Default Commitment Cost Bids.

**30.4.4.4 Insufficient Information**

In the event that the Scheduling Coordinator for a resource (other than a Multi-Stage Generating Resource or a Multi-Stage Generating Resource in its lowest configuration in which it can be started) does not provide sufficient data for the CAISO to determine the resource’s Default Commitment Cost Bids or one or more components of the resource’s Default Commitment Cost Bids, the CAISO will assume that the resource’s Default Commitment Cost Bids, or the indeterminable component(s) of the resource’s Default Commitment Cost Bids, are zero. In the event that the Scheduling Coordinator for a Multi-Stage Generating Resource does not provide such data for an MSG Configuration beyond its lowest configuration in which it can be started, Section 30.4.5.3 applies.

**30.4.4.5 Resources with Greenhouse Gas Compliance Obligations**

For each resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the information provided to the CAISO by the Scheduling Coordinator must be consistent with the information submitted to the California Air Resources Board.

**30.4.4.6 Maximum Default Minimum Load Bid**

In no case shall a Default Minimum Load Bid exceed the Minimum Load Cost Hard Cap.

### 30.4.5 Proxy Cost Methodology

The CAISO will calculate Proxy Costs as described in this Section 30.4.5.

**30.4.5.1 Natural Gas-Fired Resources**

For each natural gas-fired resource, the CAISO will calculate a resource’s Proxy Costs based on the resource’s actual unit-specific performance parameters and applicable gas prices as described below.

 (a) **Fuel Input.** The CAISO will calculate Proxy Costs using formulaic natural gas cost values adjusted for fuel-cost variation, based on the natural gas price calculated pursuant to Section 39.7.1.1.1.3, and consistent with the requirements specified below.

(b) **Proxy Start-Up Cost.** Proxy Start-Up Costs will also include:

(i) a Variable Start-Up Operations and Maintenance Adder as provided in Section 30.4.5.4;

(ii) a greenhouse gas cost adder for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each Start-Up as the product of the resource’s fuel requirement per Start-Up, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price;

(iii) the rates for the Market Services Charge and System Operations Charge multiplied by the shortest Start-Up Time listed for the resource in the Master File, multiplied by the PMin of the resource as registered in the Master File, multiplied by 0.5; and

(iv) the cost of auxiliary power calculated using the unit-specific MWh quantity of auxiliary power used for Start-Up multiplied by a resource-specific electricity price.

(c) **Proxy Cost Minimum Load Costs.** Proxy Cost Minimum Load Costs will also include:

(i) a Variable Energy Operations and Maintenance Adder as provided in Section 30.4.5.4;

(ii) a Variable Minimum Load Operations and Maintenance Adders as provided in Section 30.4.5.4.

(iii) a greenhouse gas cost adder for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, which is calculated for each run-hour as the product of the resource’s fuel requirement at Minimum Load as registered in the Master File, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price;

(iv) the rates for the Market Services Charge and System Operations Charge multiplied by the PMin of the resource as registered in the Master File; and

(iv) the Bid Segment Fee.

 (d) **Proxy Transition Costs.** For each Multi-Stage Generating Resource under the Proxy Cost methodology, the CAISO will calculate the Proxy Transition Costs utilized for each feasible transition from a given MSG Configuration to a higher MSG Configuration based on the difference between the Proxy Start-Up Costs for the higher MSG Configuration, and the Proxy Start-Up Costs for the lower MSG Configuration, as those costs are determined in accordance with the Proxy Start-Up Cost calculation methodology set forth in Section 30.4.5. If the result of this calculation is negative for any transition between two MSG Configurations, then the associated Proxy Transition Cost shall be zero.

**30.4.5.2 Non-Natural Gas-Fired Resources**

For each non-natural gas-fired resource, the CAISO shall calculate the Proxy Start-Up Cost and Proxy Minimum Load Cost values under the Proxy Cost methodology as specified below.

1. **Fuel Input.** The Scheduling Coordinator for the resource will provide the fuel or fuel-equivalent input costs, which the CAISO will maintain in the Master File, pursuant to Section 39.7.1.1.1.2.
2. **Proxy Start-Up Costs.** Proxy Start-Up Costs will also include, if applicable:
3. a Variable Start-Up Operations and Maintenance Adder as provided in Section 30.4.5.4;
4. greenhouse gas allowance costs for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator;
5. the rates for the Market Services Charge and System Operations Charge multiplied by the shortest Start-Up Time listed for the resource in the Master File, multiplied by the PMin of the resource as registered in the Master File, multiplied by 0.5.
6. **Proxy Minimum Load Costs.** Proxy Minimum Load Costs will also include, if applicable:
7. A Variable Energy Operation and Maintenance Adder as provided in Section 30.4.5.4 multiplied by the PMin of the resource or MSG Configuration of the resource as registered in the Master File;
8. a Variable Minimum Load Operations and Maintenance Adder as provided in Section 30.4.5.4;
9. greenhouse gas allowance costs for each resource located within the CAISO Balancing Authority Area or an EIM Entity Balancing Authority Area within California, and registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator;
10. the rates for the Market Services Charge and System Operations Charge multiplied by the PMin of the resource as registered in the Master File; and
11. the Bid Segment Fee.

(d) **Proxy Transition Costs.** For each Multi-Stage Generating Resource under the Proxy Cost methodology, the CAISO will calculate the Proxy Transition Costs utilized for each feasible transition from a given MSG Configuration to a higher MSG Configuration based on the difference between the Proxy Start-Up Costs for the higher MSG Configuration, and the Proxy Start-Up Costs for the lower MSG Configuration, as those costs are determined in accordance with the Proxy Start-Up Cost calculation methodology set forth in Section 30.4.5. If the result of this calculation is negative for any transition between two MSG Configurations, then the associated Proxy Transition Cost shall be zero.

**30.4.5.3 Multi-Stage Generating Resources**

**30.4.5.3.1 Application of Proxy Costs**

For Multi-Stage Generating Resources under the Proxy Cost methodology, the CAISO will apply the Proxy Cost methodology to all the MSG Configurations. The Proxy Costs for Multi-Stage Generating Resources will be calculated for each specific MSG Configuration, including for each MSG Configuration that cannot be directly started.

**30.4.5.3.2 Insufficient Information**

Notwithstanding the rules set forth in Sections 30.4.5.1 and 30.4.5.2, to the extent that a Scheduling Coordinator for a Multi-Stage Generating Resource, other than in its lowest configuration in which the Multi-Stage Generating Resource can be started, does not provide sufficient data for the CAISO to determine a component of the Proxy Start-Up Costs or Proxy Minimum Load Costs for a particular MSG Configuration, the CAISO will, if feasible, use the value for that component associated with the next-lowest MSG Configuration.

**30.4.5.4 Variable Operations and Maintenance Adders**

**30.4.5.4.1 Generally**

Each resource that satisfies the applicable fuel source and technology requirements set forth in Section 30.4.5.4.2 will receive the default Variable Operations and Maintenance Adders specified thereunder. The Scheduling Coordinator for any resource may choose to negotiate with the CAISO pursuant to Section 30.4.5.4.3 for negotiated Variable Operations and Maintenance Adders that supersede or replace any default Variable Operations and Maintenance Adders the resource may receive. Variable Operations and Maintenance Adders are subject to renegotiation pursuant to Section 30.4.5.4.4 and to informational filings pursuant to Section 30.4.5.4.5. Pursuant to Section 30.4.5.4.6, the CAISO will convert negotiated operations and maintenance values that were established for a resource prior to January 1, 2022 into corresponding negotiated Variable Operations and Maintenance Adders.

**30.4.5.4.2 Default Variable Operations and Maintenance Adders**

The default Variable Start-Up Operations and Maintenance Adder for a frame combustion turbine resource will equal $52.13 per start per MW multiplied by the PMax of the resource or MSG Configuration of the resource.

The default Variable Minimum Load Operations and Maintenance Adder will vary by fuel source or technology as follows: (1) for a natural gas-fired combined cycle resource, the adder will equal $1.74 per run-hour per MW multipled by the PMax of the resource or MSG Configuration of the resource; (2) for an aeroderivative combustion turbine resource, the adder will equal $4.38 per run-hour per MW multiplied by the PMax of the resource or MSG Configuration of the resource; and (3) for a hydroelectric resource, the adder will equal $0.65 per run-hour per MW multiplied by the PMax of the resource or MSG Configuration of the resource.

The default Variable Energy Operations and Maintenance Adder will vary by fuel source or technology as follows: (1) nuclear $1.08/MWh; (2) coal $2.69/MWh; (3) wind $0.28/MWh; (4) natural gas-fired combined cycle units $0.59/MWh; (5) steam units $0.33/MWh; (6) geothermal $1.16/MWh; (7) landfill gas $1.21/MWh; (8) frame combustion turbines $0.97/MWh; (9) aeroderivative combustion turbines $2.15/MWh; (10) reciprocating internal combustion engines $1.10/MWh; and (11) biomass $1.65/MWh.

Effective January 1, 2022, default adders established pursuant to this Section 30.4.5.4.2 will supersede and replace any then-existing default adders established prior to that effective date.

**30.4.5.4.3 Negotiated Variable Operations and Maintenance Adders**

**30.4.5.4.3.1 Principles**

The CAISO will negotiate resource-specific and MSG Configuration-specific Variable Operations and Maintenance Adders with a Scheduling Coordinator based on the following principles:

(a) Any operations costs proposed for inclusion in the Variable Operations and Maintenance Adders must be variable operations costs, meaning the costs of consumables and other costs that vary directly with electrical production (i.e., Start-Up/Shut-Down, run-hours, or electricity output) of a resource. Variable operations costs exclude maintenance costs, auxiliary power costs, Greenhouse Gas Allowance Prices, fuel costs, grid management charges, Opportunity Costs, and other excluded costs set forth in the Business Practice Manual.

(b) Any maintenance costs proposed for inclusion in the Variable Operations and Maintenance Adders must be variable maintenance costs, meaning the costs associated with the repair, overhaul, replacement, or inspection of a resource that meet the following conditions:

(i) The costs must vary with the electrical production (i.e., Start-Up/Shut-Down, run-hours, or electricity output) of the resource.

(ii) The costs should reflect future maintenance costs that are expected to be incurred within the service life of a major component of plant or equipment.

(iii) The costs should be consistent with Good Utility Practice.

(iv) The costs should not effect a substantial betterment of the resource.

(v) If the item is a replacement, it cannot be a replacement of an existing major component of plant or equipment.

**30.4.5.4.3.2 CAISO Process**

Scheduling Coordinators may submit updated resource-specific and MSG Configuration-specific information for purposes of seeking a change to any negotiated Variable Operations and Maintenance Adder, no sooner than thirty (30) Business Days after a negotiated Variable Operations and Maintenance Adder has been determined. The CAISO will evaluate the information provided by Scheduling Coordinators, and may require Scheduling Coordinators to provide additional information, to enable the CAISO to determine reasonable negotiated Variable Operations and Maintenance Adders or to conduct audits of negotiated Variable Operations and Maintenance Adders. Within fifteen (15) Business Days of receipt of the information or any requested additional information, the CAISO will notify the Scheduling Coordinator in writing whether it has sufficient and accurate information to determine reasonable negotiated Variable Operations and Maintenance Adders to be included in the calculations for the Proxy Start-Up Cost, Proxy Minimum Load Cost, and/or Default Energy Bid under the Variable Cost Option. Within ten (10) Business Days after providing written notification to the Scheduling Coordinator that the information is sufficient and accurate, the CAISO will determine the reasonable negotiated Variable Operations and Maintenance Adders to be included in the Proxy Start-Up Costs, Proxy Minimum Load Costs, and/or Default Energy Bids under the Variable Cost Option, and will so inform the Scheduling Coordinator in writing.

In the event of a dispute regarding the sufficiency or accuracy of the information provided by the Scheduling Coordinator, the CAISO and the Scheduling Coordinator will enter a period of good-faith negotiations that terminates sixty (60) days after the date the dispute began. If the CAISO and the Scheduling Coordinator resolve the dispute during the 60-day negotiation period, within ten (10) Business Days of such agreement, the CAISO will determine the reasonable negotiated Variable Operations and Maintenance Adders and will provide the adders to the Scheduling Coordinator in writing. If the CAISO and the Scheduling Coordinator fail to agree upon the sufficiency or accuracy of the information during the 60-day negotiation period, the Scheduling Coordinator has the right to petition FERC to resolve the dispute as to the sufficiency or accuracy of its information.

In the event of a dispute regarding the CAISO’s determination of Variable Operations and Maintenance Adders, the CAISO and the Scheduling Coordinator will enter a period of good-faith negotiations that terminates sixty (60) days after the date the dispute began. If the CAISO and the Scheduling Coordinator resolve the dispute during the 60-day negotiation period, the agreed-upon negotiated Variable Operations and Maintenance Adders will be effective as of the third Business Day following the resolution date.

**30.4.5.4.3.3 FERC Process**

If the CAISO and the Scheduling Coordinator fail to agree on the Variable Operations and Maintenance Adders for the Proxy Start-Up Costs, Proxy Minimum Load Costs, and/or Default Energy Bids under the Variable Cost Option following the 60-day negotiation period, the Scheduling Coordinator has the right to file proposed values and supporting information for the adders with FERC pursuant to Section 205 of the Federal Power Act.

**30.4.5.4.3.4 Interim Variable Operations and Maintenance Adders Pending Dispute Resolution**

In the event of a dispute regarding the reasonableness of the Variable Operations and Maintenance Adders determined by the CAISO, but not a dispute regarding the sufficiency or accuracy of the information provided by the Scheduling Coordinator, the CAISO will determine reasonable interim Variable Operations and Maintenance Adders until the adders are determined by agreement between the CAISO and the Scheduling Coordinator or by FERC. Any subsequent agreement or FERC order determining the Variable Operations and Maintenance Adders will be reflected in an adjustment to the interim Variable Operations and Maintenance Adders in the next applicable Settlement Statement.

**30.4.5.4.4 Renegotiation of Variable Operations and Maintenance Adders**

The CAISO may require the renegotiation of any negotiated or interim Variable Operations and Maintenance Adders established pursuant to Section 30.4.5.4.3 that have become outdated, are possibly erroneous, or for which the Scheduling Coordinator has changed. In the renegotiation process, the CAISO may review and propose modifications to such Variable Operations and Maintenance Adders, and may require the Scheduling Coordinator to provide updated information to support their continuation.

**30.4.5.4.5 Informational Filings**

The CAISO shall make an informational filing with FERC of any default Variable Operations and Maintenance Adders established pursuant to Section 30.4.5.4.2 and any negotiated or interim Variable Operations and Maintenance Adders established pursuant to Section 30.4.5.4.3, no later than seven (7) days after the end of the month for which the Variable Operations and Maintenance Adders were established.

**30.4.5.4.6 Conversion of Existing Negotiated Values**

Notwithstanding any other provision in this Section 30.4.5.4, effective January 1, 2022, the CAISO will convert any then-existing adder values for major maintenance expenses previously established for a resource pursuant to Section 30.4.5.4 (or any predecessor of that Section), and will convert any then-existing negotiated operations and maintenance values previously established for a resource pursuant to Section 39.7.1.1.2 (or any predecessor of that Section), into corresponding negotiated Variable Operations and Maintenance Adders with values equivalent to the previously established values. Each Scheduling Coordinator for a resource for which the CAISO performs such conversions will subsequently have the option to either: (1) retain the corresponding Variable Operations and Maintenance Adders for the resource; (2) negotiate changes to all of the corresponding Variable Operations and Maintenance Adders for the resource pursuant to Section 30.4.5.4.3; or (3) negotiate changes to some of the corresponding Variable Operations and Maintenance Adders for the resource pursuant to Section 30.4.5.4.3, and have the CAISO convert the balance of the corresponding Variable Operations and Maintenance Adders into default Variable Operations and Maintenance Adders pursuant to Section 30.4.5.4.2.

**30.4.6 Use Limited Resources**

**30.4.6.1 Registration and Validation Process**

A Scheduling Coordinator seeking to obtain Use-Limited Resource status for resource(s) will follow the registration and validation process set forth in this CAISO Tariff and the Business Practice Manual. The registration and validation process requires each Scheduling Coordinator to demonstrate on an annual basis that the resource has one or more limits that meet the Use-Limited Resource criteria as set forth in Section 30.4.6.1.1 and the Business Practice Manual, and allows each Scheduling Coordinator to seek to recover Opportunity Costs for Use-Limited Resources by making the demonstration set forth in Section 30.4.6.1.2.

**30.4.6.1.1 Use-Limited Resource Criteria**

In order for a resource to be considered a Use-Limited Resource, a Scheduling Coordinator must provide sufficient documentation demonstrating that the resource has one or more limits that meet all three of the following criteria:

(1) The resource has one or more limitations affecting its number of starts, its number of run-hours, or its Energy output due to (a) design considerations, (b) environmental restrictions, or (c) qualifying contractual limitations;

(2) The CAISO Market Process used to dispatch the resource cannot recognize the resource’s limitation(s); and

(3) The resource’s ability to select hours of operation is not dependent on an energy source outside of the resource’s control being available during such hours but the resource’s usage needs to be rationed.

Design considerations that satisfy the requirements of this Section are those resulting from physical equipment limitations. A non-exhaustive list of such physical equipment limitations includes restrictions documented in original equipment manufacturer recommendations or bulletins, or limiting equipment such as storage capability for hydroelectric generating resources. Other design considerations that satisfy the requirements of this Section are those resulting from performance criteria for Demand Response Resources established pursuant to programs or contracts approved by Local Regulatory Authorities. Environmental restrictions that satisfy the requirements of this Section are those imposed by regulatory bodies, legislation, or courts. A non-exhaustive list of such environmental restrictions includes limits on emissions, water use restrictions, run-hour limitations in operating permits or other environmental limits that directly or indirectly limit starts, run hours, or MWh limits, but excludes restrictions with soft caps that allow the resource to increase production above the soft caps through the purchase of additional compliance instruments. Qualifying contractual limitations that satisfy the requirements of this Section are those contained in long-term contracts that: (i) were reviewed and approved by a Local Regulatory Authority on or before January 1, 2015, or were pending approval by a Local Regulatory Authority on or before January 1, 2015 and were later approved; and (ii) were evaluated by the Local Regulatory Authority for the overall cost-benefit of those contracts taking into consideration the overall benefits and burdens, including the limitations on such resources’ numbers of starts, numbers of run-hours, or Energy output. Contracts limits that provide for higher payments when start-up, run-hour, or Energy output thresholds are exceeded are not qualifying contractual limitations. Effective April 1, 2022, no contractual limitations will constitute qualifying contractual limitations that satisfy the requirements of this Section.

Pursuant to a process set forth in the Business Practice Manual, the CAISO will review the limits and the supporting documentation provided by the Scheduling Coordinator as well as any translation of indirect limits to determine whether the Scheduling Coordinator has made the required showing under this Section. Any dispute regarding the CAISO’s determination will be subject to the generally applicable CAISO ADR Procedures set forth in Section 13, which apply except where a CAISO Tariff provision expressly provides for a different means of resolving disputes.

The following types of resources are not eligible to register as Use-Limited Resources: Reliability Demand Response Resources, Regulatory Must-Take Generation, where 100% of the capacity is regulatory must-take, Combined Heat and Power Resources where 100% of the capacity is dedicated to a host industrial process, and Variable Energy Resources.

**30.4.6.1.2 Establishing Opportunity Cost Adders**

A Scheduling Coordinator for a Use-Limited Resource that elects the Proxy Cost methodology may seek to establish Opportunity Cost adders for any limitation(s) that meet all three (3) of the following criteria:

 (1) Satisfy the requirements of Section 30.4.6.1.1;

(2) Apply for period(s) longer than the time horizon considered in the applicable Day-Ahead Market process; and

(3) Can be reflected in a monthly, annual, and/or rolling twelve (12) month period.

The CAISO will review the documentation provided by the Scheduling Coordinator and determine whether the CAISO can calculate an Opportunity Cost pursuant to the methodology set forth in Section 30.4.6.2 using the Opportunity Cost calculator, or whether the Opportunity Cost for the limitation must instead be established pursuant to the negotiation process set forth in Section 30.4.6.3. Resources with limits that can be modelled using the Opportunity Cost calculator, are not eligible for a negotiated Opportunity Cost. Any Opportunity Cost formula rate resulting from either through the calculated or negotiated process, will remain in place unless and until the formula rate is modified or terminated by the CAISO. Opportunity Costs determined pursuant to a formula rate will remain in place until updated pursuant to Section 30.4.6.2.1 or Section 30.4.6.3 to reflect any changes in input values to the formula rate. Any Opportunity Cost bid adder will not be available until the first day of the month following the effective date of this tariff section.

A Scheduling Coordinator may submit documentation, either to establish a new limitation or to modify an existing limitation, in which case the Scheduling Coordinator can request reconsideration that may result in a new formula rate. In addition, Scheduling Coordinators must demonstrate on an annual basis that the resource has one or more limits that meet the Use-Limited Resource criteria as required pursuant to Section 30.4.6.1. In accordance with Section 39.7.1.3.2.2, the CAISO will make informational filings with FERC of any new, modified, or terminated Opportunity Cost formula rate developed pursuant to Section 30.4.6.2 or negotiated pursuant to Section 30.4.6.3.

A Use-Limited Resource to the extent it has a limitation that satisfies the requirements of Section 30.4.6.1 but applies for a period less than or equal to the time horizon considered in the Day-Ahead Market, is not eligible for an Opportunity Cost for any limitation.

**30.4.6.2 Calculation of Opportunity Cost Adders**

**30.4.6.2.1 Calculation Schedule**

The CAISO will calculate, and will update the most recent calculations of, Start-Up Opportunity Costs for each validated limitation on a Use-Limited Resource’s number of starts, Minimum Load Opportunity Costs for each validated limitation on a Use-Limited Resource’s number of run-hours, and Variable Energy Opportunity Costs for each validated limitation on a Use-Limited Resource’s Energy output for which the Scheduling Coordinator has made the required showing under Section 30.4.6.1.2. Such calculations or updated calculations will actually be used to set the adder for each validated limitation that can be reflected in a monthly or a rolling twelve (12) month period and will be advisory for each validated limitation that can be reflected in an annual period. The CAISO plans to perform the calculations and updated calculations once a month. It is possible that circumstances may prevent the CAISO from performing the calculations on a monthly basis, in which case the CAISO will prioritize the workload based on Opportunity Costs most likely to need updating. The CAISO will provide the results of the calculations or updated calculations for a Use-Limited Resource to its Scheduling Coordinator.

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.

**30.4.6.2.2 Methodology for Opportunity Cost Calculator**

For the Opportunity Cost calculator developed by the CAISO, each calculation of Opportunity Costs will equal the estimated profits foregone if the Use-Limited Resource had one fewer unit of starts, run-hours, or Energy output, whichever is applicable, in the future time period of the validated limitation. With regard to each validated limitation of the Use-Limited Resource, the calculation will take into account a margin set forth in the Business Practice Manual. The calculation will also take into account the effect of any validated limitation on a Use-Limited Resource’s number of starts, number of run-hours, or Energy output in the monthly and annual and/or rolling twelve month periods. For MSG Transitions, the Opportunity Cost for each transition will be derivative of the number of Start-Ups required for the MSG Resource to achieve a specific MSG Configuration.

The CAISO will calculate the estimated profits for each validated limitation over the future time period of the limitation based on the following estimated inputs: (a) the forecasted hourly average of fifteen-minute LMPs for Energy at the Use-Limited Resource’s PNode or Aggregated PNode multiplied by (b) the optimal hourly dispatch of the Use-Limited Resource, minus (c) the estimated monthly Proxy Start-Up Cost of the Use-Limited Resource, minus (d) the estimated monthly Proxy Minimum Load Cost of the Use-Limited Resource, minus (e) the estimated monthly variable Energy cost of the Use-Limited Resource multiplied by the difference between (f) the optimal hourly commitment and dispatch of the Use-Limited Resource and (g) the PMin of the Use-Limited Resource, minus (h) the estimated monthly Transition Cost of the Use-Limited Resource.

The CAISO will calculate input (a) listed above by executing the following steps 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 (reflecting the gas price index used in the Real-Time Market calculated pursuant to Section 39.7.1.1.1.3) from the same hour of the previous year, the Greenhouse Gas Allowance Price, calculated pursuant to Section 39.7.1.1.1.4, 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.

(2) For each future month, calculate a monthly future implied heat rate based on the applicable wholesale future power price of the applicable electric pricing hub as published by Intercontinental Exchange, the most recent Greenhouse Gas Allowance Price calculated pursuant to Section 39.7.1.1.1.4, and the natural gas future commodity price of the applicable fuel region. 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.

(3) For each future month, calculate a monthly historical implied heat rate based on the wholesale historic power price of the applicable electric pricing hub as published by Intercontinental Exchange for the same month of the previous year, the average Greenhouse Gas Allowance Price calculated pursuant to Section 39.7.1.1.1.4 for the same month of the previous year, and the average natural gas commodity price, reflecting the gas price index used in the Real-Time Market calculated pursuant to Section 39.7.1.1.1.3, of the applicable fuel region for the same month of the previous year.

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

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

(6) For each future hour, calculate the LMPs by applying the gas price index of the future month and the most recent Greenhouse Gas Allowance Price calculated pursuant to Section 39.7.1.1.1.4 to the scaled implied heat rates calculated under (5) above.

For a Use-Limited Resource that has twelve (12) or fewer months of LMP data at its PNode or Aggregated PNode, the CAISO will calculate input (a) listed above using LMP data from a comparable PNode or Aggregated PNode.

Additional detail regarding the calculation of Opportunity Costs is provided in Appendix N to the Business Practice Manual for Market Instruments. Any dispute regarding the calculation of Opportunity Costs will be subject to the CAISO ADR Procedures set forth in Section 13.

**30.4.6.3 Negotiation of Opportunity Costs**

If, after receipt of the documentation required pursuant to Section 30.4.6.1.2, the CAISO determines that it cannot rely on the Opportunity Cost calculator to calculate Opportunity Costs for an eligible limitation pursuant to Section 30.4.6.2, the CAISO will establish the Opportunity Costs for the limitation pursuant to this Section. Upon making this determination, the CAISO will notify the Scheduling Coordinator for the resource and request that the Scheduling Coordinator provide the CAISO with a proposed methodology for determining Start-Up Opportunity Costs, Minimum Load Opportunity Costs, and/or Variable Energy Opportunity Costs for the limitation along with documentation supporting the methodology, and a proposed schedule for the CAISO to update such Opportunity Cost(s) under the methodology. The CAISO will either approve the submitted Opportunity Cost methodology or enter into good-faith negotiations with the Scheduling Coordinator to establish an agreed-upon Opportunity Cost methodology and the schedule for updating the Opportunity Costs under the methodology.

If the CAISO and the Scheduling Coordinator enter into good-faith negotiations, the negotiation period will be a minimum of sixty (60) days following the provision of all required documentation by the Scheduling Coordinator. Following the 60-day period, the parties can agree to continue good-faith negotiations or the Scheduling Coordinator can exercise its right to file with FERC as described below. In the event that the CAISO and the Scheduling Coordinator are unable to agree upon negotiated Opportunity Costs before the negotiation period terminates, the CAISO may propose reasonable interim Opportunity Cost value(s) that will apply to the Use-Limited Resource until the CAISO and the Scheduling Coordinator agree upon negotiated Opportunity Costs. The Scheduling Coordinator may accept or reject the proposed interim Opportunity Cost value(s). If the Scheduling Coordinator rejects the proposed interim Opportunity Cost value(s), the Use-Limited Resource will not receive Opportunity Costs unless and until the CAISO and the Scheduling Coordinator agree upon negotiated Opportunity Costs, or such costs are established by an order issued by FERC. In the event that the negotiation period terminates without the CAISO and the Scheduling Coordinator reaching agreement upon negotiated Opportunity Costs, and the Scheduling Coordinator declines to continue negotiations, the Scheduling Coordinator may file proposed Opportunity Costs and supporting documentation with FERC pursuant to Section 205 of the Federal Power Act.

Any updates to the negotiated Opportunity Costs adders established pursuant to this Section will consist solely of updates to the Opportunity Cost values themselves, and shall not affect the methodology for establishing those values. Any change in methodology would require the Scheduling Coordinator to initiate a new request pursuant to Section 30.4.6.1.2.

**30.4.7 Registered Cost Methodology**

Under the Registered Cost methodology, the Scheduling Coordinator for a Use-Limited Resource that is eligible for Opportunity Costs and either (i) does not have at least twelve (12) consecutive months of fifteen-minute LMPs for Energy at the Use-Limited Resource’s PNode or Aggregated PNode; or (ii) has at least twelve (12) consecutive months of such LMPs but has not yet reached the start of the second month after the end of the twelfth consecutive month of having such LMPs, may register values of its choosing for Default Start-Up Bids and/or Default Minimum Load Bids in the Master File subject to the maximum limit specified in Section 39.6.1.6. A Scheduling Coordinator for a Multi-Stage Generating Resource that is a Use-Limited Resource registering Default Start-Up Bids must also register Default Transition Bids for each feasible MSG Transition, subject to the maximum limit specified in Section 39.6.1.7. For a Use-Limited Resource to be eligible for the Registered Cost methodology there must be sufficient information in the Master File to calculate the value pursuant to the Proxy Cost methodology, which will be used to validate the specific value registered using the Registered Cost methodology. Any such values will be fixed for a minimum of thirty (30) days in the Master File unless:

(a) the resource’s costs for any such value, as calculated pursuant to the Proxy Cost methodology, exceed the value registered using the Registered Cost methodology, in which case the Scheduling Coordinator may elect to switch to the Proxy Cost methodology for the balance of any thirty (30)-day period, except as set forth in Section 30.4.7; or

(b) any cost registered in the Master File exceeds the maximum limit specified in Section 39.6.1.6 or Section 39.6.1.7 after this minimum thirty (30)-day period, in which case the value will be lowered to the maximum limit specified in Section 39.6.1.6 or Section 39.6.1.7.

If a Multi-Stage Generating Resource elects to use the Registered Cost methodology, that election will apply to all the MSG Configurations for that resource. The cap for the Registered Cost values for each MSG Configuration will be based on the Proxy Cost values calculated for each MSG Configuration, including for each MSG Configuration that cannot be directly started, which are also subject to the maximum limits specified in Sections 39.6.1.6 and 39.6.1.7.

## 30.5 Bidding Rules

### 30.5.1 General Bidding Rules

(a) All Bids submitted by Scheduling Coordinators to the DAM for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day, but no sooner than seven (7) days prior to the Trading Day. All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the RTM for the following Trading Day shall be submitted starting from the time of publication of DAM results for the Trading Day, and ending seventy-five (75) minutes prior to each applicable Trading Hour in the RTM. Scheduling Coordinators may submit only one set of Bids to the RTM for a given Trading Hour, which the CAISO uses for all Real-Time Market processes. ;

(b) Bid prices submitted by a Scheduling Coordinator for Energy accepted and cleared in the IFM and scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM . Bid prices for Energy submitted but not scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM. Incremental Bid prices for Energy associated with Day-Ahead AS or RUC Awards in Bids submitted to the RTM may be revised.

(c) A Scheduling Coordinator may submit in the Real-Time Market new daily Start-Up Bids, Minimum Load Bids, and Transition Bids for resources and MSG Configurations for which the Scheduling Coordinator previously submitted such Bids in the Day-Ahead Market, except for: (1) Trading Hours in which a resource or MSG Configuration has received a Day-Ahead Schedule or has received a Start-Up Instruction in RUC; and (2) Trading Hours that span the Minimum Run Time of the resource or MSG Configuration after the CAISO has committed the resource or the Scheduling Coordinator has self-committed the resource in the RTM.

(d) Scheduling Coordinators may revise ETC Self-Schedules for Supply in the RTM to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Participating TO in accordance with Section 16.

(e) Scheduling Coordinators may revise TOR Self-Schedules for Supply only in the HASP to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Non-Participating TO in accordance with Section 17. Energy associated with awarded Ancillary Services capacity cannot be offered in the Real-Time Market separate and apart from the awarded Ancillary Services capacity.

(f) Scheduling Coordinators may submit Energy Bids, AS Bids and RUC Bids in the DAM that are different for each Trading Hour of the Trading Day.

(g) Bids for Energy or capacity that are submitted to one CAISO Market, but are not accepted in that market are no longer a binding commitment and Scheduling Coordinators may submit Bids in a subsequent CAISO Market at a different price.

(h) The CAISO shall be entitled to take all reasonable measures to verify that Scheduling Coordinators meet the technical and financial criteria set forth in Section 4.5.1 and the accuracy of information submitted to the CAISO pursuant to this Section 30.

(i) In order to retain the priorities specified in Section 31.4 and 34.12 for scheduled amounts in the Day-Ahead Schedule associated with ETC and TOR Self-Schedules or Self-Schedules associated with Regulatory Must-Take Generation, a Scheduling Coordinator must submit to the Real-Time Market ETC or TOR Self-Schedules, or Self-Schedules associated with Regulatory Must-Take Generation, at or below the Day-Ahead Schedule quantities associated with the scheduled ETC, TOR, or Regulatory Must-Take Generation Self-Schedules. If the Scheduling Coordinator fails to submit such Real-Time Market ETC, TOR, or Regulatory Must-Take Generation Self-Schedules, the defined scheduling priorities of the ETC, TOR, or Regulatory Must-Take Generation Day-Ahead Schedule quantities may be subject to adjustment in the HASP and the Real-Time Market as further provided in Sections 31.4 and 34.12 in order to meet operating conditions.

(j) For Multi-Stage Generating Resources that receive a Day-Ahead Schedule, RUC Award, or Ancillary Services Award, the Scheduling Coordinator must submit an Energy Bid in the Real-Time Market for the same Trading Hour(s). If the Scheduling Coordinator submits an Economic Bid for such Trading Hour(s), the Economic Bid must be for either: the same MSG Configuration scheduled or awarded in the Integrated Forward Market, or the MSG Configuration committed in RUC. If the Scheduling Coordinator submits a Self-Schedule in the Real-Time Market for such Trading Hour(s), then the Energy Self-Schedule may be submitted in any registered MSG Configuration, including the MSG Configuration awarded in the Day-Ahead Market, that can support the awarded Ancillary Services (as further required by Section 8).

(k) Scheduling Coordinators for Multi-Stage Generating Resources may submit into the Real-Time Market bids from up to six (6) MSG Configurations in addition to the MSG Configuration scheduled or awarded in the Integrated Forward Market and Residual Unit Commitment, 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.

(l) 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 (6) MSG Configurations into the RTM.

(m) 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.

(n) 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 at least one MSG Configuration into the Day-Ahead Market and Real-Time Market that is capable of fulfilling that Resource Adequacy obligation, as feasible. The Economic Bid shall cover the entire capacity range between the maximum bid-in Energy MW and the higher of Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin as registered in the Master File.

(o) 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.

(p) 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.

(q) If in any given Trading Hour the Multi-Stage Generating Resource was awarded Regulation or Operating Reserves in the IFM, any Self-Schedules or 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.

(r) If a Multi-Stage Generating Resource has received a binding RUC Start-Up Instruction as provided in Section 31, any Self-Schedule or Submission to Self-Provide Ancillary Services in the RTM must be in the same MSG Configuration committed in RUC.

(s) If in any given Trading Hour the Multi-Stage Generating Resource is scheduled for Energy in the IFM, any Self-Schedules the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be for the same MSG Configuration for which Energy is scheduled in IFM for that Multi-Stage Generating Resource in that given Trading Hour.

(t) For a Multi-Stage Generating Resource, the Bid(s) submitted for the resource’s configuration(s) shall collectively cover the entire capacity range 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 as registered in the Master File. This rule shall apply separately to the Day-Ahead Market and the Real-Time Market.

(u) A Scheduling Coordinator may submit a Self-Schedule Hourly Block for the RTM as an import to or an export from the CAISO Balancing Authority Area and may also submit Self-Scheduled Hourly Blocks for Ancillary Services imports. Such a Bid shall be for the same MWh quantity for each of the four (4) fifteen (15)-minute intervals that make up the applicable Trading Hour.

(v) A Scheduling Coordinator may submit a Variable Energy Resource Self-Schedule for the RTM can be submitted from a Variable Energy Resource. A Scheduling Coordinator can use either the CAISO forecast for Expected Energy in the RTM or can provide its own forecast for Expected Energy pursuant to the requirements specified in Section 4.8.2. The Scheduling Coordinator must indicate in the Master File whether it is using its own forecast or the CAISO forecast for its resource in support of the Variable Energy Self-Schedule. The Scheduling Coordinator is not required to include the same MWh quantity for each of the four (4) fifteen (15)-minute intervals that make up the applicable Trading Hour for the Variable Energy Resource Self-Schedule include. If an external Variable Energy Resource that is not using a forecast of its output provided by the CAISO submits a Variable Energy Resource Self-Schedule and the Expected Energy is not delivered in the FMM, the Scheduling Coordinator for the Variable Energy Resource will be subject to the Under/Over Delivery Charge as described in Section 11.31. Scheduling Coordinators for Dynamically Scheduled Variable Energy Resources that provide the CAISO with a two (2)-hour rolling forecast with five (5)-minute granularity can submit Variable Energy Resource Self-Schedules.

(w) Scheduling Coordinators can submit Economic Hourly Block Bids to be considered in the HASP and to be accepted as binding Schedules with the same MWh award for each of the four (4) FMM intervals. Scheduling Coordinator can also submit Economic Hourly Block Bids for Ancillary Services. As specified in Section 11, a cleared Economic Hourly Block Bid is not eligible for Bid Cost Recovery.

(x) Scheduling Coordinators can submit Economic Hourly Block Bids with Intra-Hour Option. If accepted in the HASP, such a Bid creates a binding schedule with same MWh awards for each of the four (4) FMM intervals. After that, the RTM can optimize such schedules for economic reasons once through an FMM during the Trading Hour. As specified in Section 11, a cleared Economic Hourly Block Bid with Intra-Hour Option is not eligible for Bid Cost Recovery.

(y) A Scheduling Coordinator submitting Bids to the RTM is not required to submit a Self-Schedule Hourly Block, a Variable Energy Resource Self-Schedule, an Economic Hourly Block Bid, or an Economic Hourly Block Bid with Intra-Hour Option, and may instead choose to participate in the RTM through Economic Bids or Self-Schedules.

(z) For a Wheeling Through Self Schedule to be eligible as a Priority Wheeling Through for a given month, the Scheduling Coordinator must notify the CAISO of the MW quantity of the power supply contract MW supporting the export Self-Schedule of the Priority Wheeling Through transaction and confirm it meets the eligibility requirements to support a Priority Wheeling Through. The Scheduling Coordinator must provide such information to the CAISO by 45 days prior to the applicable month.

(aa) A Scheduling Coordinator for a CAISO Balancing Authority Area resource will indicate through a resource parameter as prescribed in the Business Practice Manual that it has sold capacity to an out-of-balancing authority area Load Serving Entity, and no CAISO Load Serving Entity has a right to such capacity. If the Scheduling Coordinator does not indicate this status, the resource cannot be a designated resource for an export Self-Schedule at Scheduling Points backed by non-Resource Adequacy Capacity. The CAISO will notify a Scheduling Coordinator hourly, to the extent practicable, that its resource, which is flagged to support an export, is designated by another entity to support export Self-Schedules at Scheduling Points backed by non-Resource Adequacy Capacity. Upon receiving the notice, the Scheduling Coordinator for the designated resource shall notify the CAISO if it does not have a contractual commitment to support such export Self-Schedule or does not have a reasonable expectation to be available to support the export Self Schedule. The Scheduling Coordinator for the designated resource and the Scheduling Coordinator for the export Self-Schedule shall designate a resource to support such export only if the resource is expected to have sufficient available capacity to support the export quantity throughout the entire hour. For Variable Energy Resources, this requirement can only be satisfied if the resource’s forecasted output for each of the applicable four (4) fifteen (15) minute intervals in the applicable hour for which a bid has been submitted, based on the most recent forecast for that hour, is for Generation that is equal to or greater than the Self Schedule export quantity. The designated capacity must be the deliverable capacity of a resource with Full Capacity Deliverability Status, Partial Capacity Deliverability Status, or Interim Deliverability Status that is shown on the CAISO’s NQC list.

(bb) In addition to meeting any obligations applicable to Resource Adequacy Resources, a Scheduling Coordinator for a resource supporting Self-Schedules of exports at Scheduling Points backed by non-Resource Adequacy Capacity shall submit a RUC Availability Bid for RCU at $0/MW for a quantity equal to or greater than the quantity of the export.

(cc) The Scheduling Coordinator for the resource shall offer Energy Bids into the Real-Time Market to support Self-Schedules of exports at Scheduling Points backed by non-Resource Adequacy Capacity.

(dd) The positive difference in quantity between the higher of a designated resource’s Day-Ahead Schedule or a designated resource’s RUC Schedule and the Day-Ahead Schedule of the corresponding Self-Schedule at a Scheduling Point backed by non-Resource Adequacy Capacity cannot back additional exports at a Scheduling Point backed by non-Resource Adequacy Capacity scheduled in the Real-Time Market.

(ee) A Scheduling Coordinator shall not schedule an import Self-Schedule to support an export Self-Schedule of exports at Scheduling Points explicitly sourced by non-Resource Adequacy Capacity. The transaction is properly scheduled as a Wheeling Through transaction as described in section 30.5.4.

### 30.5.2 Supply Bids

**30.5.2.1 Common Elements for Supply Bids**

In addition to the resource-specific Bid requirements of this Section, all Supply Bids must contain the following components: Scheduling Coordinator ID Code; Resource Location or Resource ID, as appropriate; MSG Configuration ID, as applicable; PNode or Aggregated Pricing Node as applicable; Energy Bid Curve, as applicable; Self-Schedule component; Ancillary Services Bid; RUC Availability Bid as applicable; Imbalance Reserves Bid as applicable; the CAISO Market to which the Bid applies; Trading Day to which the Bid applies; Priority Type (if any), and a Transaction ID as created by the CAISO. Supply Bids offered in the CAISO Markets must be monotonically increasing. Energy Bids in the RTM must also contain a Bid for Ancillary Services to the extent the resource is certified and capable of providing Ancillary Service in the RTM up to the registered certified capacity for that Ancillary Service less any Day-Ahead Ancillary Services Awards.

Scheduling Coordinators must submit the applicable Supply Bid components, including Self-Schedules, for the submitted MSG Configuration.

Scheduling Coordinators submitting Bids for Scheduling Points must adhere to the E-Tagging requirements outlined in Section 30.5.7.

**30.5.2.2 Supply Bids for Participating Generators**

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for Participating Generators shall contain the following components as applicable: Start-Up Bid, Minimum Load Bid, Ramp Rate, Minimum and Maximum Operating Limits; Energy Limit, Regulatory Must-Take/Must-Run Generation; Contingency Flag; and Contract Reference Number (if any). Scheduling Coordinators submitting these Bid components for a Multi-Stage Generating Resource must do so for the submitted MSG Configuration. Scheduling quantities that a Scheduling Coordinator schedules as Regulatory Must-Take Generation for a CHP Resource shall be limited to the quantity necessary in any hour to meet the reasonably anticipated industrial host’s thermal requirements and shall not exceed any established RMTMax values. The CHP Resource owner or operator shall provide its Scheduling Coordinator with the Regulatory Must-Take Generation values and is solely responsible for the accuracy of the information. The Scheduling Coordinator for the CHP Resource will schedule the quantities consistent with information provided subject to any contract rights between the CHP Resource Generating Unit owner or operator and its counter-party to any power purchase agreement regarding curtailment or dispatchability of the CHP Resource. If the CHP Resource Generating Unit has a power purchase agreement and its counter-party is not the Scheduling Coordinator for the resource, the parties to the agreement share the responsibility for ensuring that the Scheduling Coordinator schedules the resource consistent with contractual rights of the counter-parties. A Scheduling Coordinator for a Physical Scheduling Plant or a System Unit may include Generation Distribution Factors as part of its Supply Bid. If the Scheduling Coordinator has not submitted the Generation Distribution Factors applicable for the Bid, the CAISO will use default Generation Distribution Factors stored in the Master File. All Generation Distribution Factors used by the CAISO will be normalized based on Outage data that is available to the automated market systems. A Multi-Stage Generating Resource and its MSG Configurations are registered under a single Resource ID and Scheduling Coordinator for the Multi-Stage Generating Resource must submit all Bids for the resource’s MSG Configurations under the same Resource ID. For a Multi-Stage Generating Resources Scheduling Coordinators may submit bid curves for up to ten individual MSG Configurations of their Multi-Stage Generating Resources into the Day-Ahead Market and up to three individual MSG Configurations into the Real-Time Market. Scheduling Coordinators for Multi-Stage Generating Resources must submit a single Operational Ramp Rate for each MSG Configuration for which it submits a supply Bid either in the Day-Ahead Market or Real-Time Market. For Multi-Stage Generating Resources the Scheduling Coordinator may submit the Transition Times, which cannot be greater than the maximum Transition Time registered in the Master File. To the extent the Scheduling Coordinator does not submit the Transition Time that is a registered feasible transition the CAISO will use the registered maximum Transition Time for that MSG Transition for the specific Multi-Stage Generating Resource.

**30.5.2.3 Supply Bids for Participating Loads, Including Pumped-Storage Hydro Units and Aggregated Participating Loads**

In addition to the common elements listed in Section 30.5.2.1, Scheduling Coordinators submitting Supply Bids for Participating Loads, which includes Pumping Load or Pumped-Storage Hydro Units, may include the following components: Pumping Level (MW), Minimum Load Bid (Generation mode only of a Pumped-Storage Hydro Unit), Load Distribution Factor, Ramp Rate, Energy Limit, Pumping Cost, and Pump Shut-Down Costs. If no values for Pumping Cost or Pump Shut-Down Costs are submitted, the CAISO will generate these Bid components based on values in the Master File. Scheduling Coordinators may only submit Supply Bids for Aggregated Participating Loads by using a Generating Unit or Physical Scheduling Plant Resource ID for the Demand reduction capacity represented by the Aggregated Participating Load as set forth in a Business Practice Manual. The CAISO will use Generation Distribution Factors provided by the Scheduling Coordinator for the Aggregated Participating Load.

**30.5.2.4 Supply Bids for System Resources**

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for Resource-Specific System Resources shall also contain Start-Up Bids and Minimum Load Bids. Resource-Specific System Resources are subject to the Proxy Cost methodology or the Registered Cost methodology for Default Start-Up Bids and Default Minimum Load Bids as provided in Section 30.4, and Transaction ID as created by the CAISO. Other System Resources are not eligible to recover Start-Up Costs and Minimum Load Costs. Resource-Specific System Resources are eligible to participate in the Day-Ahead Market on an equivalent basis as Generating Units and are not obligated to participate in RUC or the RTM if the resource did not receive a Day-Ahead Schedule unless the resource is a Resource Adequacy Resource. If the Resource-Specific System Resource is a Resource Adequacy Resource, the Scheduling Coordinator for the resource is obligated to make it available to the CAISO Market as prescribed by Section 40.6. Dynamic Resource-Specific System Resources are also eligible to participate in the RTM on an equivalent basis as Generating Units. The quantity (in MWh) of Energy categorized as Interruptible Imports (non-firm imports) can only be submitted through Self-Schedules in the Day-Ahead Market and cannot be incrementally increased in the RTM. Bids submitted to the Day-Ahead Market for ELS Resources will be applicable for two days after they have been submitted and cannot be changed the day after they have been submitted. Bids for System Resources that exceed the Soft Energy Bid Cap are subject to the rules in Sections 30.7.12, as applicable.

**30.5.2.4.1 Intertie Block Bids**

Intertie Block Bids must contain the same energy Bid price for all hours of the period for which the Intertie Block Bid is submitted. Intertie Block Bids may only be submitted in the DAM.

**30.5.2.5 Supply Bids for Metered Subsystems**

Consistent with the bidding rules specified in this Section 30.5, Scheduling Coordinators that represent MSS Operators may submit Bids, including Self-Schedules and Submissions to Self-Provide an Ancillary Service, to the DAM. All Bids to supply Energy by MSS Operators must identify each Generating Unit on an individual unit basis. The CAISO will not accept aggregated Generation Bids without complying with the requirements of Section 4.9.12 of the CAISO Tariff. All Scheduling Coordinators that represent MSS Operators must submit Demand Bids at the relevant MSS LAP. Scheduling Coordinators that represent MSS Operators must comply with Section 4.9 of the CAISO Tariff. For an MSS that elects Load following, the MSS Operator shall also self-schedule or bid Supply to match the Demand Forecast. All Bids for MSSs must be identify each Generating Unit on an individual unit basis or a System Unit. For an MSS that elects Load following consistent with Section 4.9.13.2, the Scheduling Coordinator for the MSS Operator must include the following additional information with its Bids: the Generating Unit(s) that are Load following; the range of the Generating Unit(s) being reserved for Load following; whether the quantity of Load following capacity is either up or down; and, if there are multiple Generating Units in the MSS, the priority list or distribution factors among the Generating Units. The CAISO will not dispatch the resource within the range declared as Load following capacity, leaving that capacity entirely available for the MSS to dispatch. The CAISO uses this information in the IFM runs and the RUC to simulate MSS Load following. The Scheduling Coordinator for the MSS Operator may change these characteristics through the Bid submission process in the RTM.

If the Load following resource is also an RMR Unit, the MSS Operator must not specify the RMR Contract Capacity specified in the RMR Contract as Load following up or down capacity to allow the CAISO to access such capacity for RMR Dispatch.

**30.5.2.6 Supply Bids for Distributed Energy Resource Aggregations**

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for Distributed Energy Resource Aggregations will contain the following components as applicable: Generation Distribution Factors, Ramp Rate, Minimum and Maximum Operating Limits; Energy Limit, and Contingency Flag. If the Scheduling Coordinator does not submit the Generation Distribution Factors for the Bid, the CAISO will use default Generation Distribution Factors registered in Master File.

**30.5.2.7 Ancillary Service Bids**

There are four distinct Ancillary Services: Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve. A resource shall be eligible to provide Ancillary Service if it has complied with the CAISO’s certification and testing requirements as contained in Appendix K and the CAISO’s Operating Procedures. Scheduling Coordinators may use Dynamic System Resources to Self-Provide Ancillary Services as specified in Section 8. All System Resources, including Dynamic System Resources and Non-Dynamic System Resources, will be charged the Shadow Price as prescribed in Section 11.10, for any awarded Ancillary Services. A Scheduling Coordinator may submit Ancillary Services Bids for Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve for the same capacity by providing a separate price in $/MW per hour as desired for each Ancillary Service. The Bid for each Ancillary Services is a single Bid segment. Only resources certified by the CAISO as capable of providing Ancillary Services are eligible to provide Ancillary Services and submit Ancillary Services Bids. In addition to the common elements listed in Section 30.5.2.1, all Ancillary Services Bid components of a Supply Bid must contain the following: (1) the type of Ancillary Service for which a Bid is being submitted; (2) Ramp Rate (Operating Reserve Ramp Rate and Regulation Ramp Rate, if applicable); and (3) Distribution Curve for Physical Scheduling Plant or System Unit. A Scheduling Coordinator may only submit an Ancillary Services Bid or Submission to Self-Provide an Ancillary Service for Multi-Stage Generating Resources for the Ancillary Service for which the specific MSG Configurations are certified. For any such certified MSG Configurations the Scheduling Coordinator may submit only one Operating Reserve Ramp Rate and Regulation Ramp Rate. An Ancillary Services Bid submitted to the Day-Ahead Market when submitted to the Day-Ahead Market may be, but is not required to be, accompanied by an Energy Bid that covers the capacity offered for the Ancillary Service. Submissions to Self-Provide an Ancillary Services submitted to the Day-Ahead Market when submitted to the Day-Ahead Market may be, but are not required to be, accompanied by an Energy Bid that covers the capacity to be self-provided. If a Scheduling Coordinator’s Submission to Self-Provide an Ancillary Service is qualified as specified in Section 8.6, the 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. Except as provided below, the Self-Schedule for Energy need not include a Self-Schedule for Energy from the resource that will be self-providing the Ancillary Service. If a Scheduling Coordinator is self-providing an Ancillary Service from a Short Start Unit, no Self-Schedule for Energy for that resource is required. If a Scheduling Coordinator proposes to self-provide Spinning Reserve, the Scheduling Coordinator is obligated to submit a Self-Schedule for Energy for that particular resource, unless as discussed above the particular resource is a Short Start Unit. When submitting Ancillary Service Bids in the Real-Time Market, Scheduling Coordinators for resources that either have been awarded or self-provide Spinning Reserve or Non-Spinning Reserve capacity in the Day-Ahead Market must submit an Energy Bid for at least the awarded or self-provided Spinning Reserve or Non-Spinning Reserve capacity, otherwise the CAISO will apply the Bid validation rules described in Section 30.7.6.1.

As provided in Section 30.5.2.6.4, a Submission to Self-Provide an Ancillary Service shall contain all of the requirements of a Bid for Ancillary Services with the exception of Ancillary Service Bid price information. In addition, Scheduling Coordinators must comply with the Ancillary Services requirements of Section 8. Scheduling Coordinators submitting Self-Schedule Hourly Blocks for Ancillary Services Bids for the Real-Time Market must also submit an Energy Bid for the associated Ancillary Services Bid under the same Resource ID, otherwise the bid validation rules in Section 30.7.6.1 will apply to cover any portion of the Ancillary Services Bid not accompanied by an Energy Bid. As described in Section 34.2.3, if the resource submits a Self-Scheduled Hourly Block, the CAISO will only use the Ancillary Services Bid in the RTM optimization and will not use the associated Energy Bid for the same Resource ID to schedule Energy from the Non-Dynamic System Resource in the RTM. Scheduling Coordinators must also comply with the bidding rules associated with the must offer requirements for Ancillary Services specified in Section 40.6.

**30.5.2.7.1 Regulation Up or Regulation Down Bid Information**

In the case of Regulation Up or Regulation Down, the Ancillary Services Bid or submission to self-provide must also contain: (a) the upward and downward range of generating capacity over which the resource is willing to provide Regulation in ten (10) minutes; (b) the Bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($/MW); and (c) the Bid price ($) of the Mileage stated separately for Regulation Up and Regulation Down. For submissions to self-provide Regulation Up or Regulation Down, the price for the capacity reservation shall be $0/MWh and the price for Mileage shall be $0. In the case of Regulation Up or Regulation Down from Dynamic System Resources, the Ancillary Services Bid must also contain the Contract Reference Number, if applicable. Scheduling Coordinators may include inter-temporal opportunity costs in their Regulation capacity bids, but these inter-temporal opportunity costs must be verifiable. Ancillary Services Bids submitted to the Day-Ahead or Real-Time Market for Regulation need not be accompanied by an Energy Supply Bid that covers the Ancillary Services capacity being offered. A Regulation Down Bid will be erased unless there is an Energy Supply Bid or Energy Self-Schedule at a level that would permit the resource to provide Regulation Down to its lower Regulation Limit. A submission to self-provide Regulation Down will be erased unless there is an Energy Self-Schedule at a level that would permit the resource to provide Regulation Down to its lower Regulation Limit. A Regulation Up Bid will be erased unless there is an Energy Supply Bid or Energy Self-Schedule at a level that would permit the resource to provide Regulation Up within its Regulation Limit. A submission to self-provide Regulation Up will be erased unless there is an Energy Self-Schedule at a level that would permit the resource to provide Regulation Up within its Regulation Limit.

**30.5.2.7.2 Spinning Reserve Capacity Bid Information**

In the case of Spinning Reserve capacity, the Ancillary Services Bid must also contain: (a) MW of additional capability synchronized to the system, immediately responsive to system frequency, and available within ten (10) minutes; (b) Bid price of capacity reservation, and (c) an indication whether the capacity reserved would be available to supply imbalance energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency (Contingency Flag). In the case of Spinning Reserve capacity from System Resources, the Ancillary Services Bid must also contain: (a) Schedule ID (NERC ID number); and (b) a Contract Reference Number, if applicable. Ancillary Services Bids and Submissions to Self-Provide an Ancillary Services submitted to the Real-Time Market for Spinning Reserves must also submit an Energy Bid that covers the Ancillary Services capacity being offered into the Real-Time Market.

**30.5.2.7.3 Non-Spinning Reserve Capacity**

In the case of Non-Spinning Reserve, the Ancillary Service Bid must also contain: (a) the MW capability available within ten (10) minutes; (b) the Bid price of the capacity reservation; (c) time of synchronization following notification (minutes); and (d) an indication whether the capacity reserved would be available to supply imbalance energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency (Contingency Flag). In the case of Non-Spinning Reserve Capacity from System Resources, the Ancillary Services Bid must also contain: (a) Schedule ID (NERC ID number); and (b) a Contract Reference Number, if applicable. In the case of Non-Spinning Reserve Capacity from Participating Load within the CAISO Balancing Authority Area, the Ancillary Service Bid must also contain: (a) a Load identification name and Location Code; (b) Demand reduction available within ten (10) minutes; (c) time to interruption following notification (minutes); and (d) maximum allowable curtailment duration (hour). In the case of Aggregated Participating Load, and Proxy Demand Resources, Scheduling Coordinators must submit Bids using a Generating Unit, Physical Scheduling Plant Resource ID, or Resource ID for the Proxy Demand Resource for the Demand reduction capacity of the Aggregated Participating Load through a Bid to provide Non-Spinning Reserve or a Submission to Self-Provide an Ancillary Service for Non-Spinning Reserve. Ancillary Services Bids and Submissions to Self-Provide an Ancillary Services submitted to the Real-Time Market for Non-Spinning Reserves must also submit an Energy Bid that covers the Ancillary Services capacity being offered into the Real-Time Market.

**30.5.2.7.4 Additional Rules for Self-Provided Ancillary Services**

Scheduling Coordinators electing to self-provide Ancillary Services shall supply the information referred to in this Section 30.5 in relation to each Ancillary Service to be self-provided, excluding the capacity price information, but including the name of the trading Scheduling Coordinator in the case of Inter-Scheduling Coordinator Ancillary Service Trades. The portion of the Energy Bid that corresponds to the high end of the resource’s operating range, shall be allocated to any awarded or Self-Provided Ancillary Services in the following order from higher to lower capacity: (a) Regulation Up; (b) Spinning Reserve; and (c) Non-Spinning Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid (i.e. that portion not associated with capacity committed to provide Ancillary Services) shall constitute a Bid to provide Energy.

**30.5.2.8 RUC Availability Bids**

Scheduling Coordinators may submit RUC Availability Bids to seek a RUC Award. Scheduling Coordinators submit separate RUC Availability Bids for RCU and RCD. For Multi-Stage Generating Resources, the RUC Availability Bids shall be submitted at the MSG Configuration. The RUC Availability Bid component is MW-quantity in $/MW per hour. The value for the $/MW per hour component of the Bid must be between 0 and 250.

Resources offering Energy Bids, other than Virtual Bids, to the IFM must submit a RUC Availability Bid for RCU at a quantity no less than the quantity of the Energy Bid.

**30.5.2.9 Imbalance Reserves Bids**

Scheduling Coordinators may submit Imbalance Reserves Bids to seek an Imbalance Reserves Award. Scheduling Coordinators submit separate Imbalance Reserves Bids for IRU and IRD. For Multi-Stage Generating Resources, the Imbalance Reserves Bids shall be submitted at the MSG Configuration level. The Imbalance Reserves component is MW-quantity in $/MW per hour. The value for the $/MW per hour component of the Bid must be between 0 and 55.

### 30.5.3 Demand Bids

Each Scheduling Coordinator representing Demand, including Non-Participating Load and Aggregated Participating Load, shall submit 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. Scheduling Coordinators must submit Demand Bids, including Self Schedules, for CAISO Demand at Load Aggregation Points except as provided in Section 30.5.3.2.

**30.5.3.1 Demand Bids Components**

Demand Bids must have the following components: Scheduling Coordinator ID Code; a Demand Bid curve that is a monotonically decreasing staircase function of no more than ten (10) segments defined by eleven (11) ordered pairs of MW and $/MWh; Location Code for the LAP, Custom LAP or PNode, as applicable; and hourly scheduled MWh within the range of the Bid curve, including any zero values, for each Settlement Period of the Trading Day.

**30.5.3.2 Exceptions to Requirement for Submission of Demand Bids and Settlement at the LAP**

The following are exceptions to the requirement that Demand Bids be submitted and settled at the LAP:

(a) ETC or TOR Self-Schedules submitted consistent with the submitted TRTC Instructions;

(b) Participating Load and Aggregated Participating Load Bids for Supply and Demand may be submitted and settled at a PNode or Custom LAP, as appropriate; and

(c) Export Bids are submitted and settled at Scheduling Points, which do not constitute a LAP.

### 30.5.4 Wheeling Through Transactions

A Wheeling Through transaction consists of an Export Bid and an Import Bid with the same Wheeling reference (a unique identifier for each Wheeling Through transaction). If the Wheeling reference does not match at the time the relevant market closes, the Wheeling Through transaction will be erased; this includes any Economic Bid or Self-Schedule for the resource for that Trading Hour. Wheeling Through transactions with matching Wheeling references will be kept balanced in the IFM and RTM; that is, to the extent an Export Bid or Import Economic Bid or Self-Schedule specify different quantities, only that matching quantity will clear the CAISO Markets.

### 30.5.5 Scheduling Sourcing/Sinking in Same Balancing Authority Area

**30.5.5.1 Prohibition**

A Scheduling Coordinator is prohibited from submitting Bids that result in a Schedule(s) being awarded to that single Scheduling Coordinator that has an associated E-Tag reflecting a source and sink in the same Balancing Authority Area. A Schedule or Schedules resulting from Bids submitted in violation of this Section 30.5.5.1 will be settled according to Section 11.2.4.7 and Section 11.33.

**30.5.5.2 Exceptions to Prohibition**

Bids that otherwise would be prohibited under Section 30.5.5.1 are permitted, and the resulting Schedule(s) will not be settled according to Section 11.2.4.7 and Section 11.33, if any of the following four conditions cause the associated E-Tag to have a source and sink in the same Balancing Authority Area.

(a) The Schedule(s) includes a transmission segment on a DC Intertie.

(b) The Schedule(s) involves a Pseudo-Tie generating unit delivering energy from its Native Balancing Authority Area to an Attaining Balancing Authority Area.

(c) 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.

(d) 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.

Provided, however, that if the circumstances leading to one of the above four conditions being met were excluded from consideration and the resulting hypothetical Schedule(s) could have an associated E-Tag reflecting a source and sink in the same Balancing Authority Area, then the Schedule(s) will be settled according to Section 11.2.4.7 and Section 11.33.

### 30.5.6 Non-Generator Resource Bids

Scheduling Coordinators must ensure that Non-Generator Resource Bids or Bids from resources using Non-Generator Resource Generic Modeling functionality contain the Bid components specified in this Section 30.5 based on how the resource is then participating in the CAISO Markets, namely, whether it is providing Supply, Demand, and/or Ancillary Services Bids. Scheduling Coordinators representing Non-Generator Resources using Regulation Energy Management must submit Bids compliant with the requirements of Section 8.4.1.2.

**30.5.6.1 State of Charge Bid Components**

In addition to the Bid components listed in this Section 30.5, Scheduling Coordinators representing Non-Generator Resources may submit Bids including the State of Charge for the Day-Ahead Market to indicate the forecasted starting physical position of the Non-Generator Resource. In the Real-Time Markets, Scheduling Coordinators representing Non-Generator Resources may submit Bids including end-of-hour state-of-charge parameters as MWh ranges or specific MWh values. Where Scheduling Coordinators seek a state-of-charge range, they may submit a minimum and maximum MWh target. Where Scheduling Coordinators seek a specific state-of-charge value, they may submit equal minimum and maximum MWh targets. The CAISO will use reasonable efforts to commit, schedule, and dispatch Non-Generator Resources to meet their end-of-hour state-of-charge targets or ranges. Scheduling Coordinators may not submit MWh targets that (i) exceed their Master File energy or capacity limits; (ii) exceed their State of Charge limits; (iii) include a minimum MWh target greater than the maximum MWh target; (iv) conflict with RA Capacity obligations; or (v) preclude meeting an Ancillary Service Award, Schedule, or Obligation. Where Scheduling Coordinators elect to submit end-of-hour state-of-charge targets, the CAISO RTM optimization processes will give them precedence over other Bid components, including without limitation, the Energy Bid Curve and Ancillary Services Bid. Where Scheduling Coordinators elect to submit end-of-hour state-of-charge parameters, the Non-Generator Resources will be ineligible for Bid Cost Recovery pursuant to Section 11.6.6. Scheduling Coordinators representing Non-Generator Resources using Regulation Energy Management may not include end-of-hour state-of-charge parameters.

**30.5.6.2 Hybrid Resource Bids**

In addition to the Bid components listed in this Section 30.5, Scheduling Coordinators representing Hybrid Resources will submit Hybrid Dynamic Limits representing Hybrid Resources’ upper economic limit and lower economic limit in each Real-Time Market five-minute Trading Interval for a rolling six-hour look-ahead period. These limits will reflect the range of the Hybrid Resource’s Economic Bids or Self-Schedules. Hybrid Dynamic Limits should reflect resource availability based on operating capabilities such as State of Charge and forecasted output from the variable component of a Hybrid Resource. Scheduling Coordinators may also use Hybrid Dynamic Limits to manage onsite charging of an energy storage component of a Hybrid Resource.

The CAISO will use reasonable efforts to issue Real-Time Market Schedules that respect Hybrid Dynamic Limits. Scheduling Coordinators may not submit Hybrid Dynamic Limits in the Day-Ahead Market.

### 30.5.7 E-Tag Rules and Treatment of Intertie Schedules

In addition to complying with all generally applicable E-Tagging requirements, Scheduling Coordinators must submit their E-Tags consistent with the requirements specified in this Section 30.5.7. If a Scheduling Coordinator receives an intra-hour Schedule change, then the Scheduling Coordinator must, by twenty minutes before the start of the FMM interval to which the Schedule change applies, ensure that an updated energy profile reflects the change. Absent extenuating circumstances, the CAISO automatically updates Energy profiles on E-Tags for Energy Schedules that change from HASP to the FMM within a Trading Hour. In performing this service for a Scheduling Coordinator, the CAISO does not assume any responsibility for compliance with any E-Tag requirements or obligations to which the Scheduling Coordinator is subject. The changed energy profile will apply for the balance of the operating hour unless it is subsequently changed by a further updated energy profile.

**30.5.7.1 Self-Schedule Hourly Blocks**

By forty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag (or set of E-Tags) that passes CAISO E-Tag validation procedures and that supports the Self-Schedule Hourly Block. If the Scheduling Coordinator fails to submit a valid E-Tag by forty minutes prior to the applicable Trading Hour, then the CAISO will set the MW quantity of the FMM Schedule associated with the Self-Schedule Hourly Block to zero for each FMM interval of the hour.

The transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour must be equal to the Self-Schedule Hourly Block. If the Scheduling Coordinator has a transmission profile less than its advisory Energy schedule, then the CAISO will limit the schedule for Energy in the FMM so that it does not exceed the quantity of the transmission profile.

The energy profile of the E-Tag at forty minutes prior to the applicable Trading Hour need not equal the Self-Schedule Hourly Block and the Scheduling Coordinator may revise the Energy profile up to twenty minutes prior to the applicable Trading Hour. At twenty minutes prior to the applicable Trading Hour, the quantity of the Energy profile must be equal to the lower of: (a) the transmission profiled of the E-Tag at forty minutes prior to the applicable Trading Hours: or (b) the Self-Schedule Hourly Block. A Scheduling Coordinator is exposed to the Under/Over Delivery Charge if the Energy profile at twenty minutes prior to the applicable Trading Hours is not equal to the Self-Schedule Hourly Block.

The CAISO may modify the Energy profile due to Reliability related curtailments.

**30.5.7.2 Variable Energy Resource Self-Schedule**

By forty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag (or set of E-Tags) that passes CAISO E-Tag validation procedures and that supports the Variable Energy Resource Self-Schedule. If the Scheduling Coordinator fails to submit a valid E-Tag by forty minutes prior to the applicable Trading Hour, then the CAISO will set the MW quantity of the FMM Schedule associated with the Variable Energy Resources Self-Schedule to zero for each FMM interval of the hour.

The transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour must be equal to the Variable Energy Resource Self-Schedule. If the Scheduling Coordinator has a transmission profile less than its advisory Energy schedule, then the CAISO will limit the schedule for Energy in the FMM so that it does not exceed the quantity of the transmission profile.

The energy profile of the E-Tag at forty minutes prior to the applicable Trading Hour need not equal the Variable Energy Resource Self-Schedule and the Scheduling Coordinator may revise the Energy profile up to twenty minutes prior to the applicable Trading Hour. At twenty minutes prior to the applicable Trading Hour, the quantity of the Energy profile must be equal to the lower of: (a) the transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour: or (b) the Variable Energy Resource Self-Schedule. A Scheduling Coordinator is exposed to the Under/Over Delivery Charge if the Energy profile at twenty minutes prior to the applicable Trading Hour is not equal to the Variable Energy Resource Self-Schedule.

The CAISO may modify the Energy profile due to the Reliability Related curtailments.

**30.5.7.3 Economic Hourly Block Bid**

By forty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag (or set of E-Tags) that passes CAISO E-Tag validation procedures and that supports the Economic Hourly Block Bid. If the Scheduling Coordinator fails to submit a valid E-Tag by forty minutes prior to the applicable Trading Hour, then the CAISO will set the MW quantity of the FMM Schedule associated with the Economic Hourly Block Bid to zero for each FMM interval of the hour

The transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour must be equal to the Economic Hourly Block Bid. If the Scheduling Coordinator has a transmission profile less than its advisory Energy schedule, then the CAISO will limit the schedule for Energy in the FMM so that it does not exceed the quantity of the transmission profile.

The energy profile of the E-Tag at forty minutes prior to the applicable Trading Hour need not equal the Economic Hourly Block Bid and the Scheduling Coordinator may revise the Energy profile up to twenty minutes prior to the applicable Trading Hour. At twenty minutes prior to the applicable Trading Hour, the quantity of the Energy profile must be equal to the lower of: (a) the transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour; or (b) the quantity of the Economic Hourly Block Bid. A Scheduling Coordinator is exposed to the Under/Over Delivery Charge if the Energy profile at twenty minutes prior to the applicable Trading Hour is not equal to the Economic Hourly Block Bid.

The CAISO may modify the Energy profile due to Reliability related curtailments.

**30.5.7.4 Economic Hourly Block Bid with Intra-Hour Option**

By forty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag (or set of E-Tags) that passes CAISO E-Tag validation procedures and that supports the Economic Hourly Block Bid with Intra-Hour Option. If the Scheduling Coordinator fails to submit a valid E-Tag by forty minutes prior to the applicable Trading Hour, then the CAISO will set the MW quantity of the FMM Schedule associated with the Economic Hourly Block Bid with Intra-Hour Option to zero for each FMM interval of the hour.

The transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour must be equal to the Economic Hourly Block Bid with Intra-Hour Option. If the Scheduling Coordinator has a transmission profile less than its advisory Energy schedule, then the CAISO will limit the schedule for Energy in the FMM so that it does not exceed the quantity of the transmission profile.

The energy profile of the E-Tag at forty minutes prior to the applicable Trading Hour need not equal the Economic Hourly Block Bid with Intra-Hour Option and the Scheduling Coordinator may revise the Energy profile up to twenty minutes prior to the applicable Trading Hour. At twenty minutes prior to the applicable Trading Hour, the quantity of the Energy profile must be equal to the lower of: (a) the transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour; or (b) the quantity of the Economic Hourly Block Bid with Intra-Hour Option. A Scheduling Coordinator is exposed to the Under/Over Delivery Charge if the Energy profile at twenty minutes prior to the applicable Trading Hour is not equal to the Economic Hourly Block Bid with Intra-Hour Option.

The CAISO may modify the Energy profile due to Reliability related curtailments.

In the case of an intra-hour redispatch from the FMM, the CAISO may increment or decrement the Energy profile to correspond to the intra-hour redispatch. The MW level to which the FMM can redispatch an Economic Hourly Block Bid with Intra-Hour Option above its HASP Advisory Schedule is limited by the quantity of the transmission profile submitted by forty minutes prior to the applicable Trading Hour.

**30.5.7.5 FMM Economic Bid**

By forty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag (or set of E-Tags) that passes CAISO E-Tag validation procedures and that supports the FMM Economic Bid. If the Scheduling Coordinator fails to submit a valid E-Tag by forty minutes prior to the applicable Trading Hour, then the CAISO will set the MW quantity of the FMM Schedule associated with the FMM Economic Bid to zero for each FMM interval of the hour.

The transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour must be greater than or equal to the FMM Economic Bid. If the Scheduling Coordinator has a transmission profile less than its advisory Energy schedule, then the CAISO will limit the schedule for Energy in the FMM so that it does not exceed the quantity of the transmission profile.

The energy profile of the E-Tag at forty minutes prior to the applicable Trading Hour need not equal the FMM Economic Bid and the Scheduling Coordinator may revise the Energy profile up to twenty minutes prior to the applicable Trading Hour. At twenty minutes prior to the applicable Trading Hour, the quantity of the energy profile must be equal to the lower of: (a) the transmission profile of the E-Tag at forty minutes prior to the applicable Trading Hour; or (b) the quantity of the FMM energy schedule for the first FMM interval of the applicable Trading Hour.

The CAISO may modify the Energy profile due to Reliability related curtailments.

Scheduling Coordinators with cleared FMM Economic Bids may update either the transmission profile or the Energy profile after forty minutes prior to the applicable Trading Hour and twenty minutes prior to the applicable Trading Hour, respectively. A Scheduling Coordinator choosing to update the transmission profile must submit an updated transmission profile at least 40 minutes prior to the applicable FMM interval. A Scheduling Coordinator choosing to update the Energy profile must submit an updated Energy profile at least 20 minutes prior to the applicable FMM interval. Cleared FMM Economic Bids are eligible for Bid Cost Recovery as specified in Section 11.8.

### 30.5.8 Demand Bids, Export Bids, Virtual Bids, and Bids for Non-Resource-Specific System Resources Above the Soft Energy Bid Cap

**30.5.8.1 Day-Ahead Market.**

Scheduling Coordinators may submit Demand Bids, Export Bids, Virtual Bids, and Bids for Non-Resource-Specific System Resources above the Soft Energy Bid Cap, not to exceed the Hard Energy Bid Cap, for any Trading Hour of the DAM in which the CAISO has accepted a Bid with an Energy Bid price that exceeds the Soft Energy Bid Cap pursuant to Section 30.7.12, or the Maximum Import Bid Price exceeds the Soft Energy Bid Cap.

**30.5.8.2 Real-Time Market**.

Scheduling Coordinators may submit Demand Bids, Export Bids, Virtual Bids, and Bids for Non-Resource-Specific System Resources above the Soft Energy Bid Cap, not to exceed the Hard Energy Bid Cap, for any Trading Hour of the Real-Time Market in which

(a) The conditions in Section 30.5.8.1 applied to the same Trading Hour of the Day-Ahead Market; or

(b) (1) The CAISO has accepted a Bid for the applicable Trading Hour of the Real-Time Market with an Energy Bid price that exceeds the Soft Energy Bid Cap pursuant to Section 30.7.12, not including Bids from Reliability Demand Response Resources, or (2) the Maximum Import Bid Price exceeds the Soft Energy Bid Cap.

## 30.6 Bidding and Scheduling of PDRs and RDRRs

### 30.6.1 Bidding and Scheduling of PDRs

Unless otherwise specified in the CAISO Tariff and applicable Business Practice Manuals, and subject to Section 30.6.3, the CAISO will treat Bids for Energy and Ancillary Services on behalf of Proxy Demand Resources like Bids for Energy and Ancillary Services on behalf of other types of supply resources. The

CAISO will only accept the following types of Bids from Proxy Demand Resources:

(i) Economic Bids for Energy or Ancillary Services;

(ii) submissions to Self-Provide Ancillary Services;

(iii) submissions of Energy Self-Schedules from Proxy Demand Resources that have provided Submissions to Self-Provide Ancillary Services;

(iv) submissions of Energy Self-Schedules in the Real-Time Market up to the Proxy Demand

Resource’s Day-Ahead Market Schedule in the same Trading Hour;

(v) RUC Availability Bids; and

(vi) Imbalance Reserves Bids

A Scheduling Coordinator for a Demand Response Provider representing a Proxy Demand Resource may Self-Provide Ancillary Services for which it is certified. The Demand Response Provider's Demand Response Services for Proxy Demand Resources will be bid separately and independently from the LSE's underlying Demand Bid.

**30.6.1.1 Bidding and Scheduling of PDRs in the Real-Time Market**

Pursuant to Section 4.13.3, Scheduling Coordinators for Proxy Demand Resources may submit Economic

Bids for Energy and Ancillary Services in the Real-Time Markets. Pursuant to Section 30.5.1(s),

Scheduling Coordinators for Proxy Demand Resources may submit Economic Hourly Block Bids to be

considered in the HASP, and to be accepted as binding Schedules with the same MWh award for each of

the four FMM intervals. A cleared Economic Hourly Block Bid is not eligible for Bid Cost Recovery.

Scheduling Coordinators for Proxy Demand Resources may not submit Economic Hourly Block Bids with

an Intra-Hour Option.

**30.6.1.2 Bidding and Scheduling of Proxy Demand Resources using the Load-Shift Methodology**

Scheduling Coordinators for Proxy Demand Resources using the load-shift methodology described in Section 4.13.4.7 will submit separate Economic Bids for the curtailment Resource ID and the consumption Resource ID that comprise the Proxy Demand Resource. The CAISO will use reasonable efforts to optimize both Resource IDs to avoid sending conflicting Schedules.

The CAISO will only accept the following types of Bids for the curtailment Resource ID:

(i) Economic Bids for Energy or Ancillary Services;

(ii) submissions to Self-Provide Ancillary Services;

(iii) submissions of Energy Self-Schedules where the curtailment Resource ID has provided Submissions to Self-Provide Ancillary Services;

(iv) submissions of Energy Self-Schedules in the Real-Time Market up to curtailment Resource ID’s Day-Ahead Market Schedule in the same Trading Hour; and

(v) RUC Availability Bids; and

(vi) Imbalance Reserves Bids.

All Economic Bids for Energy for the curtailment Resource ID must be above the Market Clearing Prices established in Section 30.6.3. For the consumption Resource ID, the CAISO will only accept Economic Bids for Energy and submissions of Energy Self-Schedules in the Real-Time Market up to its Day-Ahead Market Schedule in the same Trading Hour. All Economic Bids for the consumption Resources must be below $0/MWh.

### 30.6.2 Bidding and Scheduling of RDRRs

Unless otherwise specified in the CAISO Tariff and applicable Business Practice Manuals, and subject to Section 30.6.3, the CAISO will treat Bids for Energy on behalf of Reliability Demand Response Resources like Bids for Energy on behalf of other types of supply resources. The CAISO will only accept Economic

Bids for Energy from Reliability Demand Response Resources. A Scheduling Coordinator for a Demand Response Provider representing a Reliability Demand Response Resource may submit Economic Energy Bids for the Reliability Demand Response Resource only in the Day-Ahead Market and in the Real-Time Market, but may not submit Energy Self-Schedules for the Reliability Demand Response Resource, may not Self-Provide Ancillary Services from the Reliability Demand Response Resource, and may not submit RUC Availability Bids, Ancillary Service Bids for the Reliability Demand Response Resource, or Imbalance Reserves Bids. The Demand Response Provider’s Demand Response Services for Reliability Demand Response Resources will be bid separately and independently from the LSE’s underlying Demand Bid.

**30.6.2.1 Bidding and Scheduling of RDRRs in the Real-Time Market**

Pursuant to Section 4.13.3, Scheduling Coordinators for Reliability Demand Response Resources may submit Economic Bids for Energy in the Real-Time Markets. Scheduling Coordinators for Reliability Demand Response Resources may submit Economic Hourly Block Bids to be considered in the HASP, and to be accepted as binding Schedules with the same MWh award for each of the four FMM intervals. A cleared Economic Hourly Block Bid is not eligible for Bid Cost Recovery. Scheduling Coordinators for Reliability Demand Response Resources may not submit Economic Hourly Block Bids with an Intra-Hour Option.

**30.6.2.1.1 Limitations on Obligation to Bid in the Real-Time Market**

Within each Reliability Demand Response Services Term, any capacity of a Reliability Demand Response Resource that remains uncommitted after the Day-Ahead Market shall be bid in the Real-Time Market in order to be available to provide Demand Response Services in Real-Time until such time as the Reliability Demand Response Resource has reached the RDRR Availability Limit for the Reliability Demand Response Services Term. Within each Reliability Demand Response Services Term, any capacity of a Reliability Demand Response Resource that remains uncommitted after the Day-Ahead Market may be (but is not required to be) bid in the Real-Time Market in order to be available to provide Demand Response Services in Real-Time after the Reliability Demand Response Resource has reached the RDRR Availability Limit during the Reliability Demand Response Services Term.

**30.6.2.1.2 Real-Time Dispatch Options**

For purposes of bidding and scheduling in the Real-Time Market, each Scheduling Coordinator for a Demand Response Provider representing a Reliability Demand Response Resource shall select either the Marginal Real-Time Dispatch Option or the Discrete Real-Time Dispatch Option prior to the start of the initial Reliability Demand Response Services Term applicable to the Reliability Demand Response Resource. The selection for each Reliability Demand Response Resource shall remain in effect until such time as the Scheduling Coordinator for the Reliability Demand Response Resource chooses to change its selection from the Marginal Real-Time Dispatch Option to the Discrete Real-Time Dispatch Option or vice versa, in which case the change in selection shall go into effect at the start of the next Reliability Demand Response Services Term applicable to the Reliability Demand Response Resource. A Reliability Demand Response Resource that is subject to either the Marginal Real-Time Dispatch Option or the Discrete Real-Time Dispatch Option shall have a Default Minimum Load Bids of zero (0) dollars. To promote feasible dispatches, the CAISO will set the Minimum Load of Reliability Demand Response Resources using the Discrete Real-Time Dispatch Option at an administrative value just below the upper economic limit of its Real-Time Bid. The CAISO will add to the Reliability Demand Response Resource’s Minimum Load Bid a cost based on the product of this value and its Real-Time Bid price.

**30.6.2.1.2.1 Marginal Real-Time Dispatch Option**

A Reliability Demand Response Resource that is subject to the Marginal Real-Time Dispatch Option:

1. May submit either a single-segment Bid or a multi-segment Bid in the Real-Time Market that must be at least ninety-five percent (95%) of the applicable Soft Energy Bid Cap.

(b) When (1) the CAISO has accepted a Bid for the applicable Trading Hour of the Real-Time Market with an Energy Bid price that exceeds the Soft Energy Bid Cap pursuant to Section 30.7.12, or (2) the Maximum Import Bid Price exceeds the Soft Energy Bid Cap, may submit either a single-segment Bid or a multi-segment Bid in the Real-Time Market that must be at least ninety-five percent (95%) of the applicable Hard Energy Bid Cap, not to exceed the Hard Energy Bid Cap.

In any instance where the Scheduling Coordinator for a Reliability Demand Response Resource has submitted a Real-Time Market Bid and the Soft Energy Bid Cap changes for the same Trading Hour, the Scheduling Coordinator should submit a revised Bid by Market Close. Where the Scheduling Coordinator does not submit a revised Bid, the CAISO will automatically adjust the Bid after Market Close, maintaining the percentage of the bid cap originally submitted by the Scheduling Coordinator, not to exceed the Hard Energy Bid Cap.

(c) Shall be dispatched as a marginal resource if it is dispatched by the CAISO. For the purpose of making this determination and setting the Locational Marginal Price, the CAISO treats a Reliability Demand Response Resource as if it were flexible with an infinite Ramp Rate between zero (0) and its PMax.

**30.6.2.1.2.2 Discrete Real-Time Dispatch Option**

A Reliability Demand Response Resource that is subject to the Discrete Real-Time Dispatch Option:

(a) May submit only a single-segment Bid in the Real-Time Market that must be at least ninety-five percent (95%) of the applicable Soft Energy Bid Cap.

1. When (1) the CAISO has accepted a Bid for the applicable Trading Hour of the Real-Time Market with an Energy Bid price that exceeds the Soft Energy Bid Cap pursuant to Section 30.7.12, or (2) the Maximum Import Bid Price exceeds the Soft Energy Bid Cap, may submit only a single-segment Bid in the Real-Time Market that must be at least ninety-five percent (95%) of the applicable Hard Energy Bid Cap, not to exceed the Hard Energy Bid Cap.

In any instance where the Scheduling Coordinator for a Reliability Demand Response Resource has submitted a Real-Time Market Bid and the Soft Energy Bid Cap changes for the same Trading Hour, the Scheduling Coordinator should submit a revised Bid by Market Close. Where the Scheduling Coordinator does not submit a revised Bid, the CAISO will automatically adjust the Bid after Market Close, maintaining the percentage of the bid cap originally submitted by the Scheduling Coordinator, not to exceed the Hard Energy Bid Cap.

(c) Shall be dispatched as a discrete (non-marginal) resource if it is dispatched by the CAISO.

### 30.6.3 Net Benefits Test for PDRs or PDRRs

In accordance with Section 11.5.2.4, the CAISO will apply a net benefits test to determine a threshold Market Clearing Price for Proxy Demand Resources and Reliability Demand Response Resources. The CAISO will not accept Proxy Demand Resource or Reliability Demand

Response Resource Bids for Energy below this threshold Market Clearing Price in the CAISO Markets.

**30.6.3.1 Supply Curve Used in Applying the Net Benefits Test**

The CAISO will generate one (1) on-peak supply curve and one (1) off-peak supply curve for each month that depicts the system-wide aggregated power supplies at different offer prices in the CAISO Markets within that month. The CAISO will generate these two supply curves for each month, using the following sequential methodology:

(i) The CAISO will collect supply curve data for the month that is twelve (12) months prior to the month for which the CAISO is generating the supply curves (the reference month), using all mitigated Bids in the Real-Time Market from any Generating Unit that is either committed or uncommitted and excluding Import Bids and Export Bids.

(ii) The CAISO will adjust the supply curve data to reflect differences in resource availability and fuel prices between the target month and the reference month. Significant changes in resource availability will be determined using the averages of the hourly supply curves over the entire reference month, with the supply quantities being averaged for every price level. Significant changes in fuel prices will be determined using the simple average of the relevant fuel indices as specified in the Business Practice Manual. For every supply quantity, the corresponding price will be scaled using a scaling factor defined as the forward gas price for the Trading Month divided by the historical average gas price for the reference month. These adjustments will result in two representative supply curves for the target month, one (1) on-peak and one (1) off-peak.

(iii) The CAISO will smooth the representative supply curves to twice differentiable using an exponential form function and applying a price window that is likely to contain the threshold Market Clearing Price. The price window may need to be adjusted in the process until the smoothed supply curves fit the representative supply curves closely.

Using the smoothed supply curves, the CAISO will determine a candidate threshold Market Clearing Price for the on-peak and a threshold Market Clearing Price for the off-peak corresponding to the point on each supply curve beyond which (i) the product of the amount of supplied Power (prior to the dispatch of Proxy Demand Resources) and the reduction in Market Clearing Price that results from the dispatch of Proxy Demand Resources exceeds (ii) the product of the Market Clearing Price (prior to the dispatch of Proxy Demand Resources) and the reduction in the amount of supplied Power that results from the dispatch of Proxy Demand Resources. If the candidate threshold Market Clearing Price is outside the corresponding price window being used, the price window needs to be adjusted and this process will be repeated until the price window contains the candidate threshold Market Clearing Price and thus makes it the final threshold Market Clearing Price. If multiple candidate threshold Market Clearing Prices exist, the candidate threshold Market Clearing Price that is concave on the supply curve (a supply function of price) will be the final threshold Market Clearing Price.

**30.6.3.2 Information Posted on CAISO Website**

The net benefits test will be posted on the CAISO website, along with supporting documentation and the threshold Market Clearing Prices that were in effect in the previous twelve (12) months, and any updated supply curve analysis. The CAISO will post the threshold Market Clearing Prices determined for each month on the CAISO Website by the fifteenth (15th) day of the immediately preceding month.

## 30.7 Bid Validation

The CAISO shall validate submitted Bids pursuant to the procedures set forth in this Section 30.7 and the rules set forth in the Business Practice Manuals.

### 30.7.1 Scheduling Coordinator Access

Each Scheduling Coordinator will be provided access to the CAISO’s secure communication system to submit, modify and cancel Bids prior to the close of both the DAM and RTM, as specified in Section 30.5.1. The CAISO shall provide information regarding submitted Bids including, but not be limited to, the following: (i) notification of acceptance; (ii) notification of validation; (iii) notification of rejection; (iv) notification of status; (v) notification of submission error(s); and (vi) default modification or generation of Bids, including as further provided below, if any, on behalf of Scheduling Coordinators.

### 30.7.2 Timing of CAISO Validation

Once a Bid is submitted to the CAISO Markets, the Bid is available for validation, which is conducted in multiple steps. Clean Bids will be generated after Market Close.

### 30.7.3 Day-Ahead Market Validation

**30.7.3.1 Validation Prior to Market Close and Master File Update**

The CAISO conducts Bid validation in three steps:

**Step 1:**  The CAISO will validate all Bids after submission of the Bid for content validation which determines that the Bid adheres to the structural rules required of all Bids as further described in the Business Practices Manuals. If the Bid fails any of the content level rules the CAISO shall assign it a rejected status and the Scheduling Coordinator must correct and resubmit the Bid.

**Step 2:** After the Bids are successfully validated for content, but prior to the Market Close of the DAM, the Bids will continue through the second level of validation rules to verify that the Bid adheres to the applicable CAISO Market rules and if applicable, limits based on Master File data. If the Bid fails any level two validation rules, the CAISO shall assign the Bid as invalid and the Scheduling Coordinator must either correct or resubmit the Bid.

**Step 3:**  If the Bid successfully passes validation in Step 2, it will continue through the third level of validation where the Bid will be analyzed based on its contents to identify any missing Bid components that must be present for the Bid to be valid consistent with the market rules contained in Article III of this CAISO Tariff and as reflected in the Business Practice Manuals. At this stage the Bid will either be automatically modified for correctness and assigned a status of conditionally modified or modified, or if it can be accepted as is, the Bid will be assigned a status of conditionally valid, or valid. A Bid will be automatically modified and assigned a status of modified or conditionally modified Bid, whenever the CAISO inserts or modifies a Bid component. The CAISO will insert or modify a Bid component whenever (1) a Self-Schedule quantity is less than the lowest quantity specified as an Economic Bid for either an Energy Bid or Demand Bid, in which case the CAISO extends the Self-Schedule to cover the gap; and (2) for a Resource Adequacy Resource that is not a Use-Limited Resource, the CAISO will submit Generated Bids for Reliability Capacity as specified in Section 40.6.8. Additionally, to the extent an Eligible Intermittent Resource fails to submit a Bid for RCU up to the quantity of its forecasted output based on the forecast referenced in Section 34.1.6 the CAISO generates a bid for RCU up to the forecasted output. The price of the generated bid is at the price included in the RUC Availability Bid for RCU, or at $0/MW if the Scheduling Coordinator did not submit any such Bid. Throughout the Bid evaluation process, the Scheduling Coordinator shall have the ability to view the Bid and may choose to cancel the Bid, modify and re-submit the Bid, or leave the modified, conditionally modified or valid, conditionally valid Bid as is to be processed in the designated CAISO Market. The CAISO will not insert or extend any Bid for a Resource Adequacy Resource that is a Use-Limited Resource.

**30.7.3.2 Master File Data Update**

Except as otherwise prescribed in this tariff, once a day the Master File data is updated with changes to the Master File that were submitted between at least five (5) and up to eleven (11) Business Days in advance, after which all conditional Bids must be re-validated prior to the trading period when the Bid will take effect. After this re-validation takes place, the status of all conditionally modified and conditionally valid Bids may be changed to modified or valid, if the Bid period is for the next relevant DAM.

**30.7.3.3 Validation Prior to Market Close and After Master File Update**

Prior to the Market Close of the DAM, after the Master File data has been updated, all Bids must be re-validated using the same process as described in Section 30.7.3.1 to produce either valid Bids or modified Bids. Throughout this process the Scheduling Coordinator shall have the ability to view the Bid and may choose to re-submit (at which point the Bid would undergo the Bid validation process described in this Section 30.7 again), cancel, or modify the Bid. Valid or modified Bids that are not re-submitted or cancelled become Clean Bids after the Market Close of the DAM. Modified Bids for Resource Adequacy Resources will reflect the full capability of the resource as defined in the Master File.

**30.7.3.4 Validation After Market Close**

To the extent that a Scheduling Coordinator fails to enter a Bid for a resource that is required to submit a Bid in the full range of available capacity consistent with the bidding provisions of Section 30 or the Resource Adequacy provisions of Section 40, the CAISO will create a Bid for the Scheduling Coordinator, which is referred to as the Generated Bid. This does not apply to Load-following MSSs. The Generated Bid will be created only after the Market Close for the DAM and will be based on data registered in the Master File, and, if applicable, published natural gas pricing data and published pricing data for greenhouse gas allowances. The Generated Bid components will be calculated as set forth in Sections 30 and 40.6.8. The Scheduling Coordinator may view Generated Bids, but may not modify such Bids, unless the CAISO has approved a Reference Level Change Request for the resource’s Default Energy Bid. The CAISO will provide notice to the Scheduling Coordinator of the use of a Generated Bid prior to Market Clearing of the IFM. In addition, validation of export priority pursuant to Sections 31.4 and 34.12.1 and Wheeling Through transactions pursuant to Section 30.5.4 occur after the Market Close for the DAM.

**30.7.3.5 Bid Validation Rules for Multi-Stage Generating Resources**

If a Scheduling Coordinator does not submit a Bid in the Day-Ahead Market or Real-Time Market for a Multi-Stage Generating Resource with a Resource Adequacy must-offer obligation at a MSG Configuration that can meet the applicable Resource Adequacy must-offer obligation, the CAISO will create a Generated Bid for the default Resource Adequacy MSG Configuration. If the Multi-Stage Generating Resource is not capable of Start-Up in the default Resource Adequacy MSG Configuration, then the ISO will, based on feasibility of transitions, create a Generated Bid for every MSG Configuration that has a minimum output below the MW level of the Resource Adequacy must-offer obligation, which will cover the operating range from its minimum output to the minimum of its maximum output and the MW level of the Resource Adequacy must-offer obligation. In the event that the Scheduling Coordinator does not submit a Bid in compliance with section 30.5.1(p), the CAISO will create a Generated Bid for all of the capacity not bid into the CAISO Market between the maximum bid-in Energy MW and the higher of Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin. If the Scheduling Coordinator submits a Bid for the Multi-Stage Generating Resource, the CAISO will create this Generated Bid for the registered MSG Configurations before the Market Close, and if it does not submit such a Bid the CAISO will create this Generated Bid after the Market Close. Any Generated Bid created by the CAISO for the default Resource Adequacy MSG Configuration will be in addition to the MSG Configurations bid into the Real-Time Market by the responsible Scheduling Coordinator. If the Scheduling Coordinator submits a Bid in the Day-Ahead Market or Real-Time Market for a MSG Configuration that is not the default Resource Adequacy MSG Configuration and that does not cover the full amount of the resource’s Resource Adequacy requirements, the CAISO will create a Generated Bid for the full Resource Adequacy Capacity. Before the market closes, if a Scheduling Coordinator submits a Bid in the Day-Ahead Market or Real-Time Market for the default Resource Adequacy MSG Configuration of a Multi-Stage Generating Resource that only meets part of the resource’s Resource Adequacy must-offer obligation, the CAISO will extend the last segment of the Energy Bid curve in the submitted Bid for the Multi-Stage Generating Resource up to the Multi-Stage Generating Resource’s Resource Adequacy must-offer obligation. After the market closes, to the extent that no Bid is submitted into the Real-Time Market for a Multi-Stage Generating Resource scheduled in the Integrated Forward Market as required in Section 30.5 the CAISO will create a Self-Schedule for MSG Configuration equal to the Day-Ahead Schedule for that resource for the MSG Configuration scheduled in the IFM. To the extent a Multi-Stage Generating Resource is awarded Operating Reserves in the Day-Ahead Market and no Economic Energy Bids is submitted for that resource in the Real-Time Market, the CAISO will insert Proxy Energy Bid in the MSG Configuration that was awarded in the Day-Ahead Market to cover the awarded Operating Reserves. The CAISO will validate that the combination of the Day-Ahead Ancillary Services Awards and Submissions to Self-Provide Ancillary Services are feasible with respect to the physical operating characteristics of the applicable MSG Configuration. The CAISO will reject Ancillary Services Bids or Submissions to Self-Provide Ancillary Services for MSG Configurations that are not certified Ancillary Services. For any given Multi-Stage Generating Resource, for any given CAISO Market and Trading Hour if one MSG Configuration’s Bid fails the bid validation process, all other Bids for all other MSG Configurations are also invalidated.

**30.7.3.6 Additional Bid Validation Rules for Virtual Bids**

In addition to the validation rules described in Section 30.7.3.1, Virtual Bids will be subject to the following additional validation rules.

**30.7.3.6.1 Scheduling Coordinator Validation**

The CAISO will validate that the SCID associated with a Virtual Bid is submitted from a Scheduling Coordinator authorized to submit Virtual Bids and that the Virtual Bid is submitted at an Eligible PNode or Eligible Aggregated PNode. The CAISO will reject Virtual Bids that do not satisfy these requirements.

**30.7.3.6.2 Credit Requirement**

Virtual Bids must satisfy the credit requirements of Section 12.8. The Scheduling Coordinator will be notified if Virtual Bids fail to satisfy the credit requirements. If the Scheduling Coordinator fails to resubmit Virtual Bids that satisfy the credit requirements or to provide adequate additional Financial Security, the CAISO will reject the Scheduling Coordinator’s Virtual Bids on a last-in, first-out basis.

**30.7.3.6.3 Position Limits**

For each Convergence Bidding Entity, the CAISO will reject all Virtual Bids submitted by its Scheduling Coordinator at any Eligible PNode or Eligible Aggregated PNode (other than a Default LAP or Trading Hub) that exceed the position limits specified in this Section 30.7.3.6.3. If the Scheduling Coordinator uses multiple SCIDs on behalf of a Convergence Bidding Entity, the position limits will apply to the sum of those Virtual Bids submitted at the Eligible PNode or Eligible Aggregated PNode (other than a Default LAP or Trading Hub). The CAISO will perform all position limit calculations based on the highest Virtual Bid segment MW point submitted in the Virtual Bid Curve. The CAISO will not net Virtual Supply Bids and Virtual Demand Bids in performing the position limit calculations. The affected Scheduling Coordinator will be provided notice that position limits have been violated. If the Scheduling Coordinator does not resubmit Virtual Bids within the position limits, the CAISO will reject Virtual Bids for all hours at each Eligible PNode and Eligible Aggregated PNode (other than a Default LAP or Trading Hub) where the position limits are violated. Position limits only apply to Eligible PNodes or Eligible Aggregated PNodes (other than Default LAPs or Trading Hubs).

**30.7.3.6.3.1 Position Limits at Eligible PNodes and Eligible Aggregated PNodes**

For an Eligible PNode associated with a single physical supply resource, the CAISO will publish a locational limit that will be equal to the PMax of the physical supply resource. For an Eligible PNode or Eligible Aggregated PNode (other than a Default LAP or Trading Hub) associated with more than one physical supply resource, the CAISO will publish a locational limit that will be equal to the sum of the PMaxes of the physical supply resources. For an Eligible PNode associated with a single physical demand resource, the CAISO will publish a locational limit that will be equal to the forecast of the maximum MW consumption of the physical demand resource. For an Eligible PNode or Eligible Aggregated PNode (other than a Default LAP or Trading Hub) associated with more than one physical demand resource, the CAISO will publish a locational limit that will be equal to the forecast of the maximum MW consumption of the physical demand resources. The percentages used to calculate the position limits for each Convergence Bidding Entity at Eligible PNodes and Eligible Aggregated PNodes (other than Default LAPs or Trading Hubs) will be the following percentages of the published locational limits:

(a) Position limits of ten (10) percent will apply during the time period beginning as of the effective date of this tariff provision through the last day of the eighth month following the effective date of this tariff provision.

(b) Position limits of fifty (50) percent will apply during the time period beginning as of the first day of the ninth month following the effective date of this tariff provision through the last day of the twelfth month following the effective date of this tariff provision.

(c) Position limits will cease to apply beginning on the first day of the month as of the first anniversary of the effective date of this tariff provision.

The CAISO will enforce the position limits for Eligible PNodes and Eligible Aggregated PNodes (other than Default LAPs or Trading Hubs) at the time of Virtual Bid submission. It is possible for the enforcement of position limits on a later-submitted Virtual Bid to cause a previously approved Virtual Bid to be rejected, if both of those Virtual Bids are submitted by a Scheduling Coordinator on behalf of the same Convergence Bidding Entity at the same Eligible PNode or Eligible Aggregated PNode (other than a Default LAP or Trading Hub). The CAISO will timely publish the locational limits for Eligible PNodes and Eligible Aggregated PNodes (other than Default LAPs or Trading Hubs).

**30.7.3.6.3.2 [Not Used]**

### 30.7.4 RTM Validation

RTM Bids will include the same validation process implemented in the DAM with the following additional rules. The CAISO will not validate the Bid before and again after the Master File Data update. RTM Bids are only validated based on the current Master File Data on the relevant Trading Day.

The CAISO will insert a Generated Bid or extend an Energy Bid or Self-Schedule in the RTM to cover any Day-Ahead Schedule, RUC Award, or Imbalance Reserves Award in the absence of the required Self-Schedule or Economic Bid components, or to fill in any gaps between any Self-Schedule Bid and any Economic Bid components to cover a Day-Ahead Schedule, RUC Award, or Imbalance Reserves Award. To the extent that an Energy Bid to the HASP/RTM is not accompanied by an Ancillary Services Bid, the CAISO will insert a Spinning Reserve and Non-Spinning Reserve Ancillary Services Bid at $ 0/MW for any certified Operating Reserve capacity. The CAISO also will generate a Self-Schedule Bid for any Generating Unit that has a Day-Ahead Schedule but has not submitted Bids in HASP/RTM, up to the quantity in the Day-Ahead Schedule.

### 30.7.5 Validation of ETC Self-Schedules

ETC Self-Schedules shall be validated pursuant to the procedures set forth in Section 16.6.

### 30.7.6 Validation and Treatment of Ancillary Services Bids

**30.7.6.1 Validation of Ancillary Services Bids**

Throughout the validation process described in Section 30.7, the CAISO will verify that each Ancillary Services Bid conforms to the content, format and syntax specified for the relevant Ancillary Service. If the Ancillary Services Bid does not so conform, the CAISO will send a notification to the Scheduling Coordinator notifying the Scheduling Coordinator of the errors in the Bids as described in Section 30.7. When the Bids are submitted, a technical validation will be performed to verify that the bid quantity of Regulation, Spinning Reserve, or Non-Spinning Reserve does not exceed the certified Ancillary Services capacity for Regulation, or Operating Reserves on the Generating Units, System Units, Participating Loads, Proxy Demand Resources, and external imports/exports bid. The Scheduling Coordinator will be notified within a reasonable time of any validation errors. For each error detected, an error message will be generated by the CAISO in the Scheduling Coordinator’s notification screen, which will specify the nature of the error. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit if it is still within the CAISO’s timing requirements. The Scheduling Coordinator is also notified of successful validation. If a resource is awarded or has qualified Self-Provided Ancillary Services in the Day-Ahead Market, the following rules will apply: (1): if no Energy Self-Schedule is submitted to support a Submission to Self-Provide an Ancillary Service for Regulation, the Submission to Self-Provide an Ancillary Service will be invalidated: (2) if no Energy Supply Bid is submitted to cover the awarded or Self- Provided Ancillary Services for Spinning Reserve or Non-Spinning Reserve by the Market Close of the RTM, the CAISO will generate or extend an Energy Supply Bid as necessary to cover the awarded or Self-Provided Ancillary Services capacity using the registered values in the Master File and relevant fuel prices as described in the Business Practice Manuals for use in the RTM and IFM. If an AS Bid or Submission to Self-Provide an AS is submitted in the Real-Time Market for Spinning Reserve or Non-Spinning Reserve without an accompanying Energy Supply Bid at all, the AS Bid or Submission to Self-Provide an Ancillary Service will be erased. If an AS Bid is submitted in the Real-Time Market for Spinning Reserve and Non-Spinning Reserve with only a partial Energy Supply Bid for the AS capacity, the CAISO will generate an Energy Supply Bid for the uncovered portions. If a Submission to Self-Provide an Ancillary Service is submitted in the Real-Time Market for Spinning Reserve and Non-Spinning Reserve with only a partial Energy Supply Bid for the AS capacity bid in, the CAISO will not generate or extend an Energy Supply Bid for the uncovered portions. For Generating Units with certified Regulation capacity, if there no Bid for Regulation in the Real-Time Market, but there is a Day-Ahead award for Regulation Up or Regulation Down or a submission to self-provide Regulation Up or Regulation Down, respectively, the CAISO will generate a Regulation Up or Regulation Down Bid at the default Ancillary Service Bid price of $0 up to the certified Regulation capacity for the Generating Unit minus any Regulation awarded or self-provided in the Day- Ahead. If there is a Bid for Regulation Up or Regulation Down in the Real-Time Market, the CAISO will increase the respective Bid up to the certified Regulation capacity for the Generating Unit minus any Regulation awarded or self-provided in the Day-Ahead. If a Self-Schedule amount is greater than the Regulation Limit for Regulation Up, the Regulation Up Bid will be erased.

Notwithstanding any of the provisions of Section 30.7.6.1 set forth above, the CAISO will not insert or extend any Bid for Regulation Up or Regulation Down for a Use-Limited Resource of a Load Following MSS Operator. The CAISO will not insert a Spinning Reserve and Non-Spinning Reserve Ancillary Service Bid at $0 in the Real-Time Market for any certified Operating Reserve capacity of a resource unless that resource submits an Energy Supply Bid but fails to submit an Ancillary Service Bid in the Real-Time Market.

**30.7.6.2 Treatment of Ancillary Services Bids**

When Scheduling Coordinators bid into the Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve markets, they may submit Bids for the same capacity into as many of these markets as desired at the same time by providing the appropriate Bid information to the CAISO. The CAISO optimization will evaluate AS Bids simultaneously with Energy Bids. A Scheduling Coordinator may specify that its Bid applies only in the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices for the Spinning Reserve, Non-Spinning Reserve, and Regulation markets. A Scheduling Coordinator providing one or more Regulation Up, Regulation Down, Spinning Reserve or Non-Spinning Reserve services may not change the identification of the Generating Units or Proxy Demand Resources offered in the Day-Ahead Market or in the Real-Time Market for such services unless specifically approved by the CAISO (except with respect to System Units, if any, in which case Scheduling Coordinators are required to identify and disclose the resource specific information for all Generating Units, Participating Loads, and Proxy Demand Resources constituting the System Unit for which Bids and Submissions to Self-Provide Ancillary Services are submitted into the CAISO’s Day-Ahead Market and Real-Time Market).

The following principles will apply in the treatment of Ancillary Services Bids in the CAISO Markets:

(a) not differentiate between bidders for Ancillary Services and Energy other than through cost, price, effectiveness, and capability to provide the Ancillary Service or Energy, and the required locational mix of Ancillary Services;

(b) select the bidders with most cost effective Bids for Ancillary Service capacity which meet its technical requirements, including location and operating capability to minimize the costs to users of the CAISO Controlled Grid;

(c) evaluate the Day-Ahead Bids over the twenty-four (24) Settlement Periods of the following Trading Day along with Energy, taking into account Transmission Constraints and AS Regional Limits;

(d) evaluate Import Bids along with Bids from internal resources (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area);

(e) establish Real-Time Ancillary Service Awards through the FMM from imports and resources internal to the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) at fifteen (15) minutes intervals to the hour of operation; and

(f) procure sufficient Ancillary Services in the Day-Ahead and Real-Time Markets to meet its forecasted requirements.

### 30.7.7 Format and Validation of Operational Ramp Rates

The submitted Operational Ramp Rate expressed in megawatts per minute (MW/min) as a function of the operating level, expressed in megawatts (MW), must be a staircase function with up to four segments. There is no monotonicity requirement for the Operational Ramp Rate. The submitted Operational Ramp Rate shall be validated as follows:

1. The range of the submitted Operational Ramp Rate must cover the entire capacity of the resource, from the minimum to the maximum operating capacity, as registered in the Master File for the relevant resource.

(b) The operating level entries must match exactly (in number, sequence, and value) the corresponding minimum and maximum Operational Ramp Rate breakpoints, as registered in the Master File for the relevant resource.

(c) If a Scheduling Coordinator does not submit an Operational Ramp Rate for a generating unit for a day, the CAISO shall use the maximum Ramp Rate for each operating range set forth in the Master File as the Ramp Rate for that unit for that same operating range for the Trading Day.

(d) The last Ramp Rate entry shall be equal to the previous Ramp Rate entry and represent the maximum operating capacity of the resource as registered in the Master File. The resulting Operational Ramp Rate segments must lie between the minimum and maximum Operational Ramp Rates, as registered in the Master File.

(e) The submitted Operational Ramp Rate must be the same for each hour of the Trading Day, i.e., the Operational Ramp Rate submitted for a given Trading Hour must be the same with the one(s) submitted earlier for previous Trading Hours in the same Trading Day.

(f) Outages that affect the submitted Operational Ramp Rate must be due to physical constraints, reported in the CAISO’s outage management system pursuant to Section 9 and are subject to CAISO approval. All approved changes to the submitted Operational Ramp Rate will be used in determination of Dispatch Instructions for the shorter period of the balance of the Trading Day or duration of reported Outage.

(g) Operational Ramp Rate derates in the CAISO’s outage management system pursuant to Section 9 may be declared for any operational segment established in the Master File. Ramping capability through Forbidden Operating Regions are not affected by derates entered in the CAISO’s outage management system pursuant to Section 9.

(h) The amount of change in Ramp Rates from one operating range to a subsequent operating range must not exceed a 10 to 1 ratio, and any Ramp Rate change in excess will be adjusted to achieve the 10 to 1 ratio. This adjustment will also include the implicit ramp rate in the Forbidden Operating Region.

(i) For all CAISO Dispatch Instructions of Reliability Must-Run Units the Operational Ramp Rate will be the Ramp Rate declared in the Reliability Must Run Contract Schedule A.

### 30.7.8 Format and Validation of Start-Up and Shut-Down Times

For a Generating Unit or a Resource-Specific System Resource, the submitted Start-Up Time expressed in minutes (min) as a function of down time expressed in minutes (min) must be a staircase function with up to three (3) segments defined by a set of one (1) to four (4) down time and Start-Up Time pairs. The Start-Up Time is the time required to start the resource if it is offline longer than the corresponding down time. The CAISO shall model Start-Up Times for Multi-Stage Generating Resource at the MSG Configuration level and Transition Times are validated based on the Transition Matrix submitted as provided in Section 27.8. The last segment will represent the time to start the unit from a cold start and will extend to infinity. The submitted Start-Up Time function shall be validated as follows:

(a) The first down time must be zero (0) minutes.

(b) The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the maximum Start-Up Time function, as registered in the Master File for the relevant resource.

(c) The Start-Up Time for each segment must not exceed the Start-Up Time of the corresponding segment of the maximum Start-Up Time function, as registered in the Master File for the relevant resource.

(d) The Start-Up Time function must be strictly monotonically increasing, i.e., the Start-Up Time must increase as down time increases.

For Participating Load and for a Proxy Demand Resource or Reliability Demand Response Resource, a single Shut-Down time in minutes is the time required for the resource to Shut-Down after receiving a Dispatch Instruction. For Multi-Stage Generating Resources, the Scheduling Coordinator must provide Start-Up Bids for each MSG Configuration into which the resource can be started.

### 30.7.9 Format and Validation of Start-Up Bids and Shut-Down Costs

For a Generating Unit or a Resource-Specific System Resource, the submitted Start-Up Bid expressed in dollars ($) as a function of down time expressed in minutes must be a staircase function with up to three (3) segments defined by a set of one (1) to four (4) down time and Start-Up Bid pairs. The Start-Up Bid is the cost incurred to start the resource if it is offline longer than the corresponding down time. The last segment of the Start-Up Bid will represent the cost to start the resource from cold Start-Up and will extend to infinity. The CAISO will validate the submitted Start-Up Bid as follows:

(a) The first down time must be zero (0) minutes.

(b) The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the Start-Up Time information, as registered in the Master File.

(c) The Start-Up Cost for each segment must be non-negative.

(d) The Start-Up Cost Curve must be strictly monotonically increasing non-negative staircase curves (*i.e.,* the Start-Up Cost must increase as down time increases), up to three (3) segments, which represent a function of Start-Up Cost versus down time.

(e) If the Proxy Cost methodology pursuant to Section 30.4.5 applies to the resource, the Scheduling Coordinator for that resource may submit a daily Start-Up Bid for which the included Start-Up Costs must be non-negative and may be less than or equal to the resource’s Default Start-Up Bid.

(f) For a resource that is eligible and has elected to use the Registered Cost methodology pursuant to Section 30.4.7, if a Start-Up Cost value is submitted in a Start-Up Bid, the CAISO will override that submitted Start-Up Cost with the Registered Cost reflected in the Master File.

(g) If no Start-Up Cost is submitted in a Bid, the CAISO will insert the Proxy Start-Up Cost plus the applicable Start-Up Opportunity Cost, or the Master File Registered Cost based on the methodology elected pursuant to Section 30.4. If the resource has an approved Reference Level Change Request and if no Start-Up Cost is submitted in a Bid, the CAISO will insert the revised Reference Level Start-Up Cost.

(h) The Start-Up Bid for a Reliability Demand Response Resource shall be zero (0).

(i) For Participating Loads and Proxy Demand Resources, a single Shut-Down Cost in dollars ($) is the cost incurred to Shut-Down the resource after receiving a Dispatch Instruction. The submitted Shut-Down Cost must be non-negative.

(j) For Multi-Stage Generating Resources, for any MSG Configuration for which a Bid is submitted, the Scheduling Coordinator must provide the Start-Up Bid for each MSG Configuration into which the resource can be started.

### 30.7.10 Format and Validation of Minimum Load Bids

**30.7.10.1 In General**

Scheduling Coordinators may submit a Minimum Load Bid for a Generating Unit or a Resource-Specific System Resource, Participating Load, Reliability Demand response Resource, or Proxy Demand Resource, expressed in dollars per hour ($/hr) representing the cost incurred for operating the unit at Minimum Load as registered in the Master File or as modified pursuant to Section 30.7.10.2. The CAISO will validate the Minimum Load Bids as follows:

1. The submitted Minimum Load Cost must be non-negative. If the Proxy Cost methodology pursuant to Section 30.4.5 applies to the resource, the Scheduling Coordinator for that resource may submit a daily Bid for the Minimum Load Bid that must be non-negative and may be less than or equal to the Default Minimum Load Bid.
2. For a resource that is eligible and has elected to use the Registered Cost methodology pursuant to Section 30.4.7, any submitted Minimum Load Cost must be equal to the Minimum Load Cost as registered in the Master File.
3. If no Minimum Load Cost is submitted in a Bid, the CAISO will insert the Proxy Minimum Load Cost plus the applicable Minimum Load Opportunity Cost, or the Master File Registered Cost based on the methodology elected pursuant to Section 30.4. If the resource has an approved Reference Level Change Request and if no Minimum Load Cost is submitted in a Bid, the CAISO will insert the applicable Revised Default Commitment Cost Bid.

**30.7.10.2 Adjustments to Minimum Load Costs Due to Increases in Minimum Load**

For Generating Units or Resource-Specific System Resources for which the responsible Scheduling Coordinator has temporarily increased their Minimum Load through the CAISO’s outage management system as specified in Section 9.3.3, regardless of the election made pursuant to Section 30.4, the CAISO will add to the Minimum Load Costs submitted by the Scheduling Coordinator the cost of the incremental Minimum Load determined as the product of the resource’s applicable Default Energy Bid and the corresponding MWs between the resource’s original Minimum Load as registered in the Master File and the Minimum Load increased pursuant to Section 9.3.3. The CAISO will use the adjusted Minimum Load Cost in the clearing of the applicable CAISO Markets as well as for Settlement purposes as described in Section 11. For Multi-Stage Generating Resources, the adjustments to Minimum Load Cost will be made at the MSG Configuration level.

**30.7.10.3 [Not Used]**

### 30.7.11 Format and Validation of Transition Bids

The Scheduling Coordinators may submit Transition Bids for a Multi-Stage Generating Resource that must meet the following requirements:

(a) The Transition Bids are non-negative.

(b) For resources under the Proxy Cost methodology, Transition Bids must be less than or equal to the Default Transition Bids calculated under the Proxy Cost methodology.

(c) For resources under the Registered Cost methodology, Transition Bids must equal the Default Transition Bids as registered in the Master File.

(d) If no Transition Cost is submitted in a Transition Bid, the CAISO will insert the Proxy Transition Cost plus the applicable Transition Opportunity Cost, or as registered in the Master File, based on the elected methodology pursuant to Section 30.4. If the resource has an approved Reference Level Change Request and if no Transition Cost is submitted in a Bid, the CAISO will insert the difference between the applicable Revised Default Commitment Cost Bid (*i.e.*, revised Default Start-Up Bid) for the higher MSG Configuration minus the applicable Start-Up Opportunity Cost for the higher MSG configuration and the revised applicable Revised Default Commitment Cost Bid (*i.e.*, revised Default Start-Up Cost Bid) for the lower MSG Configuration minus the applicable Start-Up Opportunity Cost for the lower MSG configuration, plus the applicable transition Opportunity Cost. If the result of this calculation is negative for any transition between two MSG Configurations, then the Transition Cost shall be zero.

### 30.7.12 Validation of Bids in Excess of Soft Energy Bid Cap, Hard Energy Bid Cap, or Minimum Load Cost Hard Cap

**30.7.12.1 Generally**

Except as otherwise stated in this Section 30.7.12, the validation rules in this Section 30.7.12 apply to all Energy Bids and Minimum Load Bids submitted by Scheduling Coordinators. The provisions of Sections 30.7.12.1 through 30.7.12.4 do not apply to Virtual Bids and Energy Bids submitted for Non-Resource-Specific System Resources; the provisions of Section 30.7.12.5 apply to Virtual Bids and Energy Bids submitted for Non-Resource-Specific System Resources. The CAISO will allow Bids for Non-Resource-Specific System Resources that are Resource Adequacy Resources and that exceed the Soft Energy Bid Cap subject to the Bid price screens described in Section 30.7.12.5.1. The CAISO will allow Virtual Bids, Export Bids, Demand Bids, and Bids for Non-Resource-Adequacy System Resources that are not Resource Adequacy Resources and that exceed the Soft Energy Bid Cap subject to the rules specified in Section 30.7.12.5.2. The CAISO will reject Virtual Bids, Export Bids, Demand Bids, and Bids for Non-Resource-Specific System Resources that exceed the Hard Energy Bid Cap.

**30.7.12.2 Energy Bids that Exceed the Soft Energy Bid Cap**

In addition to all other Bid validation rules that apply to Energy Bids, if a Scheduling Coordinator submits an Energy Bid price that exceeds the Soft Energy Bid Cap, the CAISO will modify the Energy Bid price for purposes of clearing the relevant CAISO Market Process to the higher of the Soft Energy Bid Cap or the resource’s Default Energy Bid as modified pursuant to a Reference Level Change Request pursuant to Section 30.11.

**30.7.12.3 Energy Bids that Exceed the Hard Energy Bid Cap and Minimum Load Bids that Exceed the Minimum Load Cost Hard Cap**

All Energy Bid prices and Minimum Load Bid prices used in the CAISO Market Processes shall not exceed the Hard Energy Bid Cap or the Minimum Load Cost Hard Cap, respectively.

**30.7.12.4 After-Market Cost Recovery**

For any Energy Bid, except for Energy Bids for Non-Resource-Specific System Resources, Virtual Bids, Export Bids, Demand Bids, or Minimum Load Bid price submitted above the Energy Bid price or the Minimum Load Bid price the CAISO uses in the CAISO Market Processes, the Scheduling Coordinators may be eligible for after-market cost recovery pursuant to Section 30.12.

**30.7.12.5 Virtual Bids, Export Bids, Demand Bids, and Bids for Non-Resource-Specific System Resources**

**30.7.12.5.1 Bids for Non-Resource-Specific System Resources that are Resource Adequacy Resources**

The CAISO will reduce Bids for Non-Resource-Specific System Resources that are Resource Adequacy Resources that exceed the Maximum Import Bid Price to the greater of the Soft Energy Bid Cap, the Maximum Import Bid Price, or the highest-priced Energy Bid from a Resource-Specific System Resource that the CAISO has accepted for the applicable Trading Hour pursuant to Section 30.7.12.2.

**30.7.12.5.2 Virtual Bids, Export Bids, Demand Bids, and Bids for Non-Resource-Specific System Resources that are not Resource Adequacy Resources**

The CAISO will accept Virtual Bids, Export Bids, Demand Bids, and Bids for Non-Resource-Specific System Resources that are not Resource Adequacy Resources that exceed the Soft Energy Bid consistent with the conditions specified in Section 30.5.8. The CAISO will not accept Export Bids, Demand Bids, Virtual Bids, or Bids for Non-Resource-Specific System Resources that are not Resource Adequacy Resources that exceed the Hard Energy Bid Cap.

**30.7.12.5.3 Maximum Import Bid Price**

The CAISO calculates hourly Maximum Import Bid Prices for the Day-Ahead Market and Real-Time Market, separately, including for on-peak and off-peak hours. The CAISO calculates the Maximum Import Bid Price as 110 percent of the greater of the published bilateral electric index prices for the Mid-Columbia or Palo Verde trading hub locations, multiplied by an hourly shaping ratio. As detailed in the CAISO Business Practice Manual, the CAISO calculates the hourly shaping ratio for each hour by dividing the Day-Ahead Market System Marginal Energy Cost for the CAISO Balancing Authority Area in that hour of a previous representative Trading Day by the average Day-Ahead Market System Marginal Energy Cost for the CAISO Balancing Authority Area in all on-peak hours of the same previous representative Trading Day. If for any given Trading Hour the CAISO cannot calculate the Maximum Import Bid Price, the applicable Maximum Import Bid Pri

ce will be the most recently available calculated Maximum Import Bid Price.

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# 31. Day-Ahead Market

The DAM consists of the following functions performed in sequence: Bid submission and validation, the IFM MPM, IFM, RUC MPM, and RUC.

Scheduling Coordinators may submit Energy Bids, Ancillary Services Bids, RUC Availability Bids, and Imbalance Reserves Bids for an applicable Trading Day. The CAISO issues Schedules for all Supply and Demand, including Participating Load, Reliability Demand Response Resources, and Proxy Demand Resources, pursuant to their Bids as provided in this Section 31. The CAISO also issues RUC Awards and Imbalance Reserves Awards to Scheduling Coordinators pursuant to their RUC Availability Bids and Imbalance Reserves Bids, respectively, as provided in this Section 31.

## 31.1 Bid Submission and Validation in the Day-Ahead Market

Bids, including Self-Schedules and Ancillary Services Bids, and Submissions to Self-Provide an Ancillary Service shall be submitted pursuant to the submission rules specified in Section 30. There is a single Bid submission in which Scheduling Coordinators’ Bids are used for purposes of the DAM, which includes the IFM MPM, the IFM, the RUC MPM, and RUC. Scheduling Coordinators may submit Bids for the DAM as early as seven (7) days prior to the applicable Trading Day up to Market Close of the DAM for the applicable Trading Day. The CAISO will validate all Bids submitted to the DAM pursuant to the procedures set forth in Section 30.7. Scheduling Coordinators must submit Bids for participation in the IFM for Resource Adequacy Capacity as required in Section 40.

## 31.2 IFM MPM Process

After the Market Close of the DAM, the CAISO has validated the Bids pursuant to Section 30.7, and after the CAISO conducts the EDAM RSE, the CAISO performs the IFM MPM process, which is a single market run that occurs prior to the IFM Market Clearing run. The IFM MPM process determines, pursuant to Section 31.2.3, which Energy Bids need to be mitigated to the applicable Default Energy Bids and which Imbalance Reserves Bids for IRU need to be mitigated to the IRU Default Availability Bid in the IFM. For Maximum Net Dependable Capacity of Legacy RMR Units, Energy Bids will be mitigated to the RMR Proxy Bids pursuant to Section 31.2.3. The IFM MPM process optimizes resources to meet Demand reflected in Demand Bids, including Export Bids and Virtual Demand Bids, targets procurement of one hundred (100) percent of Imbalance Reserves requirements based on Bids submitted to the DAM, and to procure one hundred (100) percent of Ancillary Services requirements based on Supply Bids submitted to the DAM. Virtual Bids and Bids from Demand Response Resources, Hybrid Resources, and Participating Load are considered in the MPM process, but are not subject to Bid mitigation. Energy storage resources whose PMax is less than five (5) MW are considered in the MPM process, but not subject to Bid mitigation. Bids from Participating Load resources that are not subject to Bid mitigation will also be considered in the IFM MPM process. Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain to be subject to all applicable market power mitigation under the CAISO Tariff, including Local Market Power Mitigation. The mitigated or unmitigated Bids and RMR Proxy Bids identified in the IFM MPM process for all resources that cleared in the IFM MPM are then passed to the IFM. The CAISO performs the IFM MPM process for the IFM for the twenty-four (24) hours of the targeted Trading Day.

### 31.2.1 Determining Competitive and Non-Competitive Congestion Components in the IFM

The IFM MPM process enforces all Transmission Constraints that are expected to be enforced in the relevant market, in the base case of meeting Demand and in the separate cases of modeling the dispatch for Energy of all capacity awarded IRU and IRD, and produces dispatch levels for all resources with submitted Bids and LMPs for all Locations. Bid mitigation is determined by decomposing the Congestion component of each LMP determined in the IFM MPM process into competitive Congestion and non-competitive Congestion components. The competitive Congestion component of each LMP is calculated as the sum of the product of the shift factor and the Shadow Price for all competitive Transmission Constraints and the non-competitive Congestion component of each LMP is calculated as the sum of the product of the shift factor and the Shadow Price for all non-competitive Transmission Constraints. The non-competitive Congestion component of an LMP can be based on a Transmission Constraint deemed non-competitive in the base case of meeting Demand or in the separate case of modeling the dispatch for Energy of all capacity awarded IRU. The Reference Bus used in the MPM process will be either: (1) the Midway 500kV bus if Path 26 flow is from north to south; or (2) the Vincent 500kV bus if Path 26 flow is from south to north. The treatment of a particular Transmission Constraint as competitive or non-competitive for purposes of the IFM MPM process is determined pursuant to Section 39.7.2.

### 31.2.2 [Not Used]

### 31.2.3 IFM Bid Mitigation

**31.2.3.1 Mitigation of Energy Bids**

If the non-competitive Congestion component of an LMP calculated in an MPM process is greater than zero (0), then any resource at that Location that is dispatched in that MPM process is subject to Local Market Power Mitigation. Bids on behalf of any such resource, to the extent that they exceed the Competitive LMP plus the Competitive LMP Parameter at the resource’s Location for the DAM or RTM

process interval for which the MPM process applies, will be mitigated to the higher of the resource’s Default Energy Bid (or RMR Proxy Bid for Legacy RMR Units), as specified in Section 39, or the Competitive LMP plus the Competitive LMP Parameter at the resource’s Location for the DAM and RTM

process interval for which the MPM process applies. To the extent a Multi-Stage Generating Resource is dispatched in the MPM process and the non-competitive Congestion component of the LMP calculated at the Multi-Stage Generating Resource’s Location is greater than zero, for purposes of mitigation, all the MSG Configurations will be mitigated similarly and the CAISO will evaluate all submitted Energy Bids for all MSG Configurations based on the relevant Default Energy Bids for the applicable MSG Configuration. The CAISO will calculate the Default Energy Bids for Multi-Stage Generating Resources by submitted MSG Configuration. Any market Bids equal to or less than the Competitive LMP plus the Competitive

LMP Parameter will be retained in the DAM and RTM process.

**31.2.3.2 Mitigation of Bids for IRU**

The CAISO applies Local Market Power Mitigation to Imbalance Reserves Bid for IRU if the resource for which that Bid was submitted could provide counter-flow to a Transmission Constraint deemed non-competitive pursuant to Section 39.7.2.2(B)(a) in the case of modeling the dispatch for Energy of the capacity awarded IRU. To the extent a Bid for IRU is subject to Local Market Power Mitigation and exceeds the Competitive Locational IRU Price plus the Competitive LMP Parameter, the CAISO mitigates the Bid to the higher of the: (i) resource’s IRU Default Availability Bid; or (ii) Competitive Locational IRU Price plus the Competitive LMP Parameter.

## 31.3 Integrated Forward Market

After the IFM MPM and prior to RUC, the CAISO shall perform the IFM. The IFM (1) performs Unit Commitment and Congestion Management (2) clears mitigated or unmitigated Bids for Energy and Imbalance Reserves cleared in the MPM as well as Bids for Energy and Imbalance Reserves that were not cleared in the MPM process against bid-in Demand, taking into account transmission limits and honoring technical and inter-temporal operating constraints, such as Minimum Run Times (3) and procures Ancillary Services to meet one hundred (100) percent of the Ancillary Services requirements based on the CAISO Forecast of BAA Demand for the CAISO. The IFM utilizes a set of integrated programs that: (1) determine Day-Ahead Schedules, Imbalance Reserves Awards, and AS Awards, and related LMPs and ASMPs; and (2) optimally commits resources that are bid in to the DAM. The IFM utilizes a SCUC algorithm that optimizes Start-Up Costs, Minimum Load Costs as modified pursuant to Section 30.7.10.2, if applicable, Transition Costs, and Energy Bids along with any Bids for Ancillary Services or Imbalance Reserves as well as Self-Schedules submitted by Scheduling Coordinators. The IFM selects the optimal MSG Configuration from a maximum of ten MSG Configurations of each Multi-Stage Generating Resource as mutually exclusive resources. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, the IFM will consider the Start-Up Cost, Minimum Load Cost as modified pursuant to Section 30.7.10.2, if applicable, and Transition Cost associated with any Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration. The IFM also provides for the optimal management of Use-Limited Resources. The ELS Resources committed through the ELC Process conducted two days before the day the IFM process is conducted for the next Trading Day as described in Section 31.7 are binding.

### 31.3.1 Market Clearing and Price Determination

**31.3.1.1 Integrated Forward Market Output**

The IFM produces: (1) a set of hourly Day-Ahead Schedules, Imbalance Reserves Awards, AS Awards, and AS Schedules for all participating Scheduling Coordinators that cover each Trading Hour of the next Trading Day; and (2) the hourly LMPs for Energy and Imbalance Reserves and the ASMPs for Ancillary Services to be used for settlement of the IFM. For a Multi-Stage Generating Resource, the IFM produces a Day-Ahead Schedule for no more than one MSG Configuration per Trading Hour. In addition, the IFM will produce the MSG Transition and the MSG Configuration indicators for the Multi-Stage Generating Resource, which would establish the expected MSG Configuration in which the Multi-Stage Generating Resource will operate. During a transition, the committed MSG Configuration is considered to be the “from” MSG Configuration. The CAISO will publish the LMPs at each PNode as calculated in the IFM. In determining Day-Ahead Schedules, Imbalance Reserves Awards, AS Awards, and AS Schedules the IFM optimization will minimize total Bid Costs based on submitted and mitigated Bids while respecting the operating characteristics of resources, the operating limits of transmission facilities, and a set of scheduling priorities that are described in Section 31.4. In performing its optimization, the IFM first tries to complete its required functions utilizing Effective Economic Bids without adjusting Self-Schedules, and skips Ineffective Economic Bids and adjusts Self-Schedules only if it is not possible to balance Supply and Demand and manage Congestion in an operationally prudent manner with available Effective Economic Bids. The process and criteria by which the IFM adjusts Self-Schedules and other Non-priced Quantities are described in Sections 27.4.3, 31.3.1.3 and 31.4. The Day-Ahead Schedules are binding commitments, including the commitment to Start-Up, if necessary, to comply with the Day-Ahead Schedules. The CAISO will not issue separate Start-Up Instructions for Day-Ahead commitments. A resource’s status, however, can be modified as a result of additional market processes occurring in the RTM.

**31.3.1.2 Treatment of Ancillary Services Bids in IFM**

In clearing the IFM, the CAISO co-optimizes Energy Bids, Imbalance Reserves Bids, and Ancillary Services Bids. To the extent that capacity subject to an Ancillary Services Bid submitted in the Day-Ahead Market is not associated with an Energy Bid or Imbalance Reserves Bid, there is no co-optimization, and therefore, no opportunity cost associated with that resource for that Bid for the purposes of calculating the Ancillary Services Marginal Price as specified in Section 27.1.2.2. The capacity that will be considered when co-optimizing the procurement of Energy, Imbalance Reserves, and Ancillary Services from Bids in the IFM will consider capacity up to the total capacity of the resource as reflected in the Ancillary Services Bid as derated through the CAISO’s outage management system pursuant to Section 9, if at all. In the case of Regulation, the capacity that will be considered is the lower of the capacity of the resource offered in the Ancillary Services Bid or the upper Regulation limit of the highest Regulating Range as contained in the Master File. For any Trading Hour within the period in which the Multi-Stage Generating Resource is transitioning from one MSG Configuration to another, the IFM will not award Ancillary Services and any Submission to Self-Provide Ancillary Services will be disqualified. Any Ancillary Services Awards in the IFM to Multi-Stage Generating Resources will carry through to the Real-Time Market in the same MSG Configuration that the Multi-Stage Generating Resource is awarded in the IFM.

**31.3.1.3 Reduction of Self-Scheduled LAP Demand**

In the IFM, to the extent the market software cannot resolve a non-competitive Transmission Constraint utilizing Effective Economic Bids such that self-scheduled Load at the LAP level would otherwise be reduced to relieve the Transmission Constraint, the CAISO Market software will adjust Non-Priced Quantities in accordance with the process and criteria described in Section 27.4.3. For this purpose the priority sequence, starting with the first type of Non-Priced Quantity to be adjusted, will be:

(a) Schedule the Energy from Self-Provided Ancillary Service Bids from capacity that is obligated to offer an Energy Bid under a must-offer obligation such as from an RMR Resource or a Resource Adequacy Resource. Consistent with Section 8.6.2, the CAISO Market software could also utilize the Energy from Self-Provided Ancillary Service Bids from capacity that is not under a must-offer obligation such as from an RMR Resource or a Resource Adequacy Resource, to the extent the Scheduling Coordinator has submitted an Energy Bid for such capacity. The associated Energy Bid prices will be those resulting from the MPM process.

(b) Relax the constraint consistent with Section 27.4.3.1, and establish prices consistent with Section 27.4.3.2. No constraints, including Transmission Constraints, on Interties with adjacent Balancing Authority Areas will be relaxed in this procedure.

**31.3.1.4 Eligibility to Set the Day-Ahead LMP**

All Generating Units, Participating Loads, non-Participating Loads, Proxy Demand Resources, Reliability Demand Response Resources, System Resources, System Units, or Constrained Output Generators subject to the provisions in Section 27.7, with Bids, including Generated Bids, that are unconstrained due to Ramp Rates, MSG Transitions, Forbidden Operating Regions, or other temporal constraints are eligible to set the LMP, provided that (a) the Schedule for the Generating Unit or Resource-Specific System Resource is between its Minimum Operating Limit and the highest MW value in its Economic Bid or Generated Bid; or (b) the Schedule for the Participating Load, non-Participating Load, Proxy Demand Resources, Reliability Demand Response Resources, Non-Resource-Specific System Resource, or System Unit is between zero (0) MW and the highest MW value in its Economic Bid or Generated Bid. If (a) a resource’s Schedule is constrained by its Minimum Operating Limit or the highest MW value in its Economic Bid or Generated Bid; (b) the CAISO enforces a resource-specific constraint on the resource due to an RMR Dispatch of a Legacy RMR Unit or Exceptional Dispatch; (c) the resource is constrained by a boundary of a Forbidden Operating Region or is Ramping through a Forbidden Operating Region; or (d) the resource’s full Ramping capability is constraining its inter-hour change in Schedule, the resource cannot be marginal and thus is not eligible to set the LMP. Resources identified as MSS Load following resources are not eligible to set the LMP. A Constrained Output Generator will be eligible to set the hourly LMP if any portion of its Energy is necessary to serve Demand.

**31.3.1.5 Treatment of Imbalance Reserves Bids in IFM**

In considering Imbalance Reserves Bids in the IFM, the CAISO applies the following rules.

**31.3.1.5.1 Eligible Resource Types**

The CAISO only considers Imbalance Reserves Bids from Generating Units, Participating Loads, Proxy Demand Resources, Reliability Demand Response Resources, System Units, System Resources with a Resource ID defined in the CAISO Master File, and Physical Scheduling Plants.

**31.3.1.5.2 Fifteen-Minute Dispatchability and Start-up**

The CAISO disregards Imbalance Reserves Bids submitted from a resource that is not 15-minute dispatchable.

The CAISO disregards Imbalance Reserves Bids submitted from a resource that otherwise would be Off during the relevant period unless it has a Start-Up Time of 15 minutes or less.

**31.3.1.5.3 Energy Bid Submission Requirement**

The CAISO only considers Imbalance Reserves Bids to the extent the resource submitted an Energy Bid in the Day-Ahead Market with Economic Bids for a quantity no less than the quantity of Imbalance Reserves Bid.

**31.3.1.5.4 Ramp Capability as Limitation on Imbalance Reserves Awards**

The CAISO disregards an Imbalance Reserves Bid to the extent it exceeds the resource’s maximum 30-minute ramp capability as determined by the ramp rate defined in the CAISO Master File for the operating range covered by the Bid.

**31.3.1.5.5 Simultaneous Bids and Awards for IRU and IRD**

A Scheduling Coordinator may offer Bids for both IRU and IRD on distinct portions of capacity for the same interval for the same resource. The CAISO may award the resource both IRU and IRD based on those Bids if it is feasible to provide both.

**31.3.1.6 Imbalance Reserves Procurement**

Subject to the procurement curve described in Section 31.3.1.6.1, the CAISO procures Imbalance Reserves to meet the Imbalance Reserves Requirement for each hour and creates separate Locational IRU Prices and Locational IRD Prices at each Node based on that procurement.

**31.3.1.6.1 Establishing the Imbalance Reserves Requirement**

As further described in the Business Practice Manual, the CAISO sets each Balancing Authority Area’s Upward Imbalance Reserves Requirement and Downward Imbalance Reserves Requirement to capture the anticipated levels of upward and downward Net Load Forecast deviations between the Day-Ahead Market and the Fifteen-Minute Market, respectively, within a specified confidence interval. The CAISO sets these values based on: (a) analysis of the differences between the load, wind, and solar forecasts utilized in the Day-Ahead Market and those used in the Fifteen-Minute Market, corresponding to the same time intervals; (b) production forecasts for EIRs in each Balancing Authority Area; and (c) the CAISO Forecast of BAA Demand. For each Balancing Authority Area participating in the Day-Ahead Market, the CAISO reduces the Balancing Authority Area’s hourly Imbalance Reserves Requirement by its proportional allocation of the Diversity Benefit for EDAM.

**31.3.1.6.2 Procurement Curve**

In each run of the IFM, the CAISO procures IRU and IRD for each Balancing Authority Area participating in the Day-Ahead Market to meet their Upward Imbalance Reserves Requirement and Downward Imbalance Reserves Requirement, respectively, subject to a procurement curve. The procurement curves for IRU and IRD are calculated based on separate statistical analysis of the Upward Imbalance Reserve Requirement and Downward Imbalance Reserve Requirement for each EDAM Entity Balancing Authority Area to ensure the total cost of Imbalance Reserves Awards for IRU or IRD do not exceed the expected cost of violating Operating Reserve requirements. Provided, however, the upper bound of the procurement curve for both IRU and IRD is $55 per MW.

**31.3.1.6.3 Imbalance Reserves Deliverability and Nodal Procurement**

**31.3.1.6.3.1 Nodal Procurement of Imbalance Reserves Awards**

The CAISO optimizes procurement of Imbalance Reserves Awards such that, in the event modeled uncertainty arises fully for either the upward or downward directions, the Energy that would be dispatched from resource capacity corresponding to the Imbalance Reserves Awards, as adjusted by the applicable Deployment Factor, would not result in flows exceeding Transmission Constraints and scheduling limits, including EDAM Transfer limits, on transmission facilities identified in the Business Practice Manual.

**31.3.1.6.3.2 Nodal Distribution of Requirements**

The CAISO distributes the Upward Imbalance Reserves Requirement and Downward Imbalance Reserves Requirement to the Demand and Variable Energy Resources Locations within each Balancing Authority Area participating in the Day-Ahead Market based on distribution factors derived from historical and/or forecasted information that reflect the relative contributions of Demand and Variable Energy Resources to the overall Imbalance Reserves Requirements.**31.3.1.6.4 Congestion Revenue from Procuring Imbalance Reserves**

As further specified in the Business Practice Manual, the CAISO separately calculates Energy Congestion revenue displaced from meeting the Upward Imbalance Reserves Requirements and the Downward Imbalance Reserves Requirements as follows.

The CAISO calculates the Energy congestion revenue displaced from meeting the Upward Imbalance Reserves Requirement by calculating for each resource for each Transmission Constraint binding in the case of modeling uncertainty in the upward direction the sum of the product of the: IRU award; Deployment Factor; Shift Factor from the resource location to the binding Transmission Constraint; and Shadow Price of the Transmission Constraint.

The CAISO calculates the Energy congestion revenue displaced from meeting the Downward Imbalance Reserves Requirement by calculating for each resource for each Transmission Constraint binding in the case of modeling uncertainty in the downward direction the sum of the product of: IRD award; Deployment Factor; Shift Factor from the resource location to the binding Transmission Constraint; and Shadow Price of the Transmission Constraint.

**31.3.1.6.5 Accounting for State of Charge in Awarding Ancillary Services and Imbalance Reserves to Non-Generator Resources**

The IFM only awards an Ancillary Services Schedule or Imbalance Reserves Award to a storage resource using the Non-Generator Resource model to the extent its modeled state of charge, as determined by a methodology defined in the Business Practice Manual, can support such schedule or award.

### 31.3.2 Congestion and Transmission Losses Cost Determination

Except for those transactions exempt from such charges as specified in Section 11.2.1.5, Scheduling Coordinators will be responsible for MCC and MCL as specified in Section 27.1. The CAISO will determine the Marginal Losses surplus it has collected and will allocate such revenues to Scheduling Coordinators as described in Section 11.2.1.6.

### 31.3.3 Metered Subsystems

In clearing the IFM, the CAISO will not enforce Transmission Constraints within each MSS. The Full Network Model (FNM) includes a full model of MSS transmission networks used for power flow calculations and Transmission Constraint management in the IFM and RTM. Transmission Constraints (i.e. circuit ratings, thermal ratings, etc.) within the MSS, or at its boundaries, that are modeled in the FNM shall be monitored but not enforced in the operation of the CAISO Markets. If overloads are observed in the forward markets that are internal to the MSS or at the MSS boundaries and are attributable to MSS operations, the CAISO shall communicate such events to the Scheduling Coordinator for the MSS and coordinate any manual Re-dispatch required in Real-Time. If, independent of the CAISO, the Scheduling Coordinator for the MSS is unable to resolve Congestion internal to the MSS or at the MSS boundaries in Real-Time, the CAISO will use Exceptional Dispatch Instructions on resources that have been bid into the HASP and RTM to resolve the Congestion. Such costs will be allocated pursuant to the provisions specified in Section 11.5.6.2.5.2. The CAISO and MSS Operator shall develop specific procedures for each MSS to determine how Transmission Constraints will be handled. Costs associated with internal Congestion and Transmission Losses in the MSS will be the responsibility of the MSS Operator. The Scheduling Coordinator for the MSS shall be responsible for payment of Marginal Losses for transactions at any points of interconnection between the MSS and the CAISO Controlled Grid, and for the delivery of Energy to the MSS or from the MSS in accordance with the CAISO Tariff. For MSS Operators that elect Load following, the CAISO shall exclude the effect of Transmission Losses in the relevant MSS in the CAISO’s calculation of loss sensitivity factors used to calculate LMPs.

### 31.3.4 RTM Bidding Obligations from Imbalance Reserves Awards

An Imbalance Reserves Award for an hour obligates the resource receiving the award to submit Economic Bids for Energy to the Real-Time Market for the full range of awarded Imbalance Reserves.

The portion of the resource’s Day-Ahead Schedule for Energy below a IRD award may be Self-Scheduled in the Real-Time Market.

A resource receiving an Imbalance Reserves Award in an hour cannot submit a Self-Schedule for Energy in the Real-Time Market for a quantity in excess of its Day-Ahead Schedule for Energy minus any awards for IRD and RCD.

By forty minutes prior to the applicable Trading Hour, a System Resource receiving an Imbalance Reserves Award that has not submitted an E-Tag (or set of E-Tags) that passes CAISO E-Tag validation procedures, with the quantity (or sum of quantities) of the transmission profile no less than the sum of the Imbalance Reserves Award and any Day-Ahead Schedule for Energy will result in the CAISO deeming the untagged portion of the Imbalance Reserves Award unavailable for purposes of Section 11.2.1.8.

## 31.4 CAISO Market Adjustments to Non-Priced Quantities in the IFM

All Self-Schedules are respected by SCUC to the maximum extent possible and are protected from curtailment in the Congestion Management process to the extent that there are Effective Economic Bids that can relieve Congestion. If all Effective Economic Bids in the IFM are exhausted, resource Self-Schedules between the resource’s Minimum Load as defined in the Master File, or if applicable, as modified pursuant to Section 9.3.3, and the first Energy level of the first Energy Bid point will be subject to adjustments by the CAISO Market optimization based on the scheduling priorities listed below. This functionality of the optimization software is implemented through the setting of scheduling parameters as described in Section 27.4.3 and specified in Section 27.4.3.1 and the Business Practice Manuals. Through this process, imports and exports may be reduced to zero, Demand Bids may be reduced to zero, Price Taker Demand (LAP load) may be reduced, and Generation may be reduced to a lower operating limit (or Regulation Limit) (or to a lower Regulation Limit plus any qualified Regulation Down award or Self-Provided Ancillary Services, if applicable). Any Self-Schedules below the Minimum Load level are treated as fixed Self-Schedules and are not subject to these adjustments for Congestion Management. The provisions of this section shall apply only to the extent they do not conflict with any MSS Agreement. In accordance with Section 27.4.3.5, the resources submitted in valid TOR, ETC or Converted Rights Self-Schedules shall not be adjusted in the IFM in response to an insufficiency of Effective Economic Bids. Thus the adjustment sequence for the IFM from highest priority (last to be adjusted) to lowest priority (first to be adjusted), is as follows:

|  |  |  |
| --- | --- | --- |
| **Scheduling Run Priority** | **Scheduling Run Parameters Under Soft Energy Bid Cap (27.4.3.2)** | **Scheduling Run Parameters Under Hard Energy Bid Cap (27.4.3.3)** |
| Reliability Must Run (RMR) Generation pre-dispatch reduction  | -$6000 | -$12000 |
| Day-Ahead TOR Self-Schedules reduction (balanced demand and supply reduction)  | $5,900 (demand)/ - $5,900 (supply) | $11800 (demand)/ -$11800 (supply) |
| Day-Ahead ETC and Converted Rights Self-Schedules reduction; different ETC priority levels will be observed based upon global ETC priorities provided to the CAISO by the Responsible PTOs  | $5100 to $5900 (demand)/ -$5100 to -$5900 (supply) | $10200 to $11800 (demand)/ -$10200 to -$11800 (supply) |
| Internal Transmission Constraint relaxation for the IFM pursuant to Section 27.4.3.1 | $5000 | $10000 |
| The export Self-Schedule of a Priority Wheeling Through; Self-Schedules of CAISO Demand reduction subject to Section 31.3.1.3; exports explicitly identified in a Resource Adequacy Plan to be served by Resource Adequacy Capacity explicitly identified and linked in a Supply Plan to the exports; and Self-Schedules of exports at Scheduling Points explicitly sourced by non-Resource Adequacy Capacity | $1800 | $3600 |
| Self-Schedules of exports at Scheduling Points not explicitly sourced by non-Resource Adequacy Capacity, except those exports explicitly identified in a Resource Adequacy Plan to be served by Resource Adequacy Capacity explicitly identified and linked in a Supply Plan to the exports as set forth in Section 31.4(d), and the export Self-Schedule of a non-Priority Wheeling Through | $1050 | $2100 |
| Day-Ahead Regulatory Must-Run Generation and Regulatory Must-Take Generation reduction  | -$1350 | -$2700 |
| Other Self-Schedules of Supply reduction, and the import Self-Schedule of a Priority Wheeling Through  | -$1100 | -$2200 |
| The import Self-Schedule of a non-Priority Wheeling Through  | $0 | $0 |

### 31.4.1 [Not Used]

## 31.5 Residual Unit Commitment

The CAISO shall perform the RUC process after the IFM. As further specified in this Section 31.5, RUC procures RUC Capacity, which includes Reliability Capacity Up and Reliability Capacity Down, to address mismatches between the CAISO Forecast of BAA Demand and the physical resources committed in the IFM.

 RUC Capacity is selected by a SCUC optimization that uses the same Base Market Model used in the IFM adjusted as described in Section 27.5.1 and 27.5.6 to help ensure the deliverability of Energy from the RUC Capacity. That optimization procures RUC Capacity by Node and creates separate RUC Prices for RCU and RCD by Node. In the case of Multi-Stage Generating Resources, the RUC will optimize Transition Costs in addition to the Start-Up and Minimum Load Costs. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, the RUC will consider the Start-Up Cost, Minimum Load Cost, and Transition Cost associated with any Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration.

### 31.5.1 RUC Participation

**31.5.1.1 Capacity Eligible for RUC Participation**

Scheduling Coordinators may make capacity available for participation in RUC by submitting a RUC Availability Bid, provided the Scheduling Coordinator has also submitted an Energy Bid (other than a Virtual Bid) for such capacity into the IFM. As part of the Bid validation procedures specified in Section 30.7.3, the CAISO disregards RUC Availability Bids from capacity that is not accompanied in the IFM by an Energy Bid that is not a Virtual Bid. Virtual Bids are not eligible to participate in RUC. Load that is not a Participating Load and Reliability Demand Response Resources are not eligible to participate in RUC. RUC participation is required for Resource Adequacy Capacity. System Resources with a Resource ID defined in the CAISO Master File are eligible to participate in RUC and will be considered on an hourly basis; that is, RUC will not observe any multi-hour block constraints. A Long Start Unit is eligible to participate in RUC to the extent it has submitted an Energy Bid to the Day-Ahead Market above PMin. In RUC the CAISO may commit a Multi-Stage Generating Resource with a Resource Adequacy must-offer obligation at any MSG Configuration with capacity equal to or greater than the MSG Configuration committed in the Integrated Forward Market. RUC will observe the Energy Limits that may have been submitted in conjunction with Energy Bids to the IFM. Legacy RMR Unit capacity will be considered in RUC in accordance with Section 31.5.1.3. MSS resources may participate in RUC in accordance with Section 31.5.2.3. COG resources are accounted for in RUC, but may not submit or be paid RUC Availability Payments. The ELS Resources committed through the ELC Process conducted two days before the day the RUC process is conducted for the next Trading Day as described in Section 31.7 are binding.

**31.5.1.2 RUC Availability Bids**

With the exception of capacity from Eligible Intermittent Resources, Scheduling Coordinators may only submit RUC Availability Bids for capacity (above the Minimum Load as registered in the Master File) for which they are also submitting an Energy Bid (other than a Virtual Bid) to participate in the IFM. A Scheduling Coordinator representing an Eligible Intermittent Resource must submit RUC Availability Bids for RCU at a quantity equal to their forecasted output based on the forecast referenced in Section 34.1.6. Any available RMR Capacity will be optimized at $0/MW in RUC.

**31.5.1.3 Legacy RMR Treatment**

If a Legacy RMR Unit is determined to have a generation requirement for any Trading Hour of the next day, either by the MPM process or by the CAISO through a Manual RMR Dispatch, and if any portion of the generation requirement has not been cleared in the IFM, the entire portion of the generation requirement will be represented as a Legacy RMR Generation Self-Schedule in the RUC.

**31.5.1.4 Eligibility to Set the RUC Price**

All resources that are eligible for RUC participation as described in Section 31.5.1.1 with RUC Bids, other than resources with RUC Capacity resulting from RUC Availability Bids inserted pursuant to Section 31.5.1.5, that are unconstrained due to Ramp Rates or other temporal constraints, including MSG Transitions, are eligible to set the RUC Price, provided the Schedule for the eligible resource other than a Generating Unit or Resource-Specific System Resource is between zero (0) MW and the highest MW value in its Economic Bid or Generated Bid. If (a) a resource’s Schedule is constrained by its Minimum Operating Limit or the highest MW value in its Economic Bid or Generated Bid, (b) the CAISO enforces a resource-specific constraint on the resource due to an RMR Dispatch Notice or Exceptional Dispatch or (c) the resource’s full Ramping capability is constraining its inter-hour change in Schedule, the resource cannot be marginal and thus is not eligible to set the RUC Price. Resources identified as MSS Load following resources are not eligible to set the RUC Price.

**31.5.1.5 RCU Bid Insertion for Exports and Eligible Intermittent Resources**

The CAISO inserts RUC Availability Bids for RCU: (a) if an Economic Bid to export Energy is awarded in the IFM and is not accompanied by a RUC Availability Bid for RCU of at least the same quantity as the Economic Bid for Energy; (b) for Self-Schedules of exports not explicitly sourced by non-Resource Adequacy Capacity awarded in the IFM; and (c) for a Scheduling Coordinator representing an Eligible Intermittent Resource that fails to submit a RUC Availability Bid for RCU as required by Section 31.5.1.2. For parts (a) and (b), the quantity of the inserted Bid is the quantity of the Day-Ahead Schedule for Energy and the price of the inserted Bid is formulated to maintain the merit order of the resource’s Energy Bid in the IFM. For part (c), the quantity of the inserted Bid is the quantity not covered by a RUC Availability Bid for RCU as required by Section 31.5.1.2 and the price of the inserted Bid is above the Default Availability Bid and below the RUC power balance constraint penalty price parameter specified in the Business Practice Manual.

### 31.5.2 [Not Used]

**31.5.2.1 [Not Used]**

**31.5.2.2 [Not Used]**

**31.5.2.2.1 [Not Used]**

**31.5.2.2.2[Not Used]**

**31.5.2.3 [Not Used]**

### 31.5.3 RUC Procurement Target

Subject to Sections 31.5.3.1 and 31.5.4, the RUC Procurement Target for each Balancing Authority Area participating in the Day-Ahead Market is based on the relationship between the CAISO Forecast of BAA Demand and the Supply cleared in the IFM for that Trading Hour (excluding Virtual Supply).

If the CAISO Forecast of BAA Demand exceeds the Supply cleared in the IFM for a Trading Hour (excluding Virtual Supply), then the RUC Procurement Target for that Balancing Authority Area is RCU in the amount of the excess Demand.

If the Supply (excluding Virtual Supply) cleared in the IFM for a Trading Hour exceeds the CAISO Forecast of BAA Demand, then the RUC Procurement Target for that Balancing Authority Area is RCD in the amount of the excess Supply.

If the Supply (excluding Virtual Supply) cleared in the IFM for a Trading Hour equals the CAISO Forecast of BAA Demand, then the RUC Procurement Target for that Balancing Authority Area is zero RCU and zero RCD.

The adjustments listed in Sections 31.5.3.1 to 31.5.3.1.6 will be made to the CAISO Forecast of BAA Demand to account for the conditions as provided therein. The RUC Procurement Target setting procedure is designed to meet the requirements of reliable grid operation without unnecessary over-procurement of RUC Capacity or over-commitment of resources. Additional detail on the process for setting the RUC Procurement Target is specified in the Business Practice Manuals.

**31.5.3.1 CAISO Operator Review & Adjustment**

The CAISO Operator reviews the CAISO Forecast of BAA Demand and all calculated adjustments as provided in Sections 31.5.3.1.1 through 31.5.3.1.6. The CAISO Operator shall accept, modify, or reject such adjustments based on Good Utility Practice. If the CAISO Operator determines it must modify the CAISO Forecast of BAA Demand, the CAISO Operator shall log sufficient information as to reason, Operating Hour, and specific modification(s) made to the CAISO Forecast of BAA Demand.

**31.5.3.1.1 RUC Net Short Conditions**

The CAISO Operator may conform the CAISO Forecast of BAA Demand in the event the CAISO Operator has determined that additional capacity may need to be procured in RUC to meet anticipated Real-Time system conditions. The CAISO Operator will consider factors such as: CAISO Forecast of BAA Demand error; weather pattern that is expected to continue or change within the next Trading Day; generator outage resulting in different Supply availability than was bid into the Day-Ahead Market; fire that threatens transmission lines and/or corridors; the expectation that the amount of Generation committed in the IFM will not be sufficient to meet the anticipated Demand; and Reliability Coordinator next-day analysis of system conditions.

**31.5.3.1.2 Demand Response Adjustments.**

The CAISO shall account for Demand response that is clearly communicated to the CAISO as certain to be curtailed for the next Trading Day only for the two following types of Demand response: (1) Demand response triggered by a staged System Emergency event; and (2) Demand response that is triggered by a price or an event known in advance. If an LSE informs the CAISO of anticipated Demand response prior to Market Close of the DAM, the CAISO Forecast of BAA Demand used as the RUC procurement target will be reduced accordingly.

**31.5.3.1.3 [Not Used]**

**31.5.3.1.4 Eligible Intermittent Resource Adjustment**

Scheduling Coordinators for Eligible Intermittent Resources may submit Bids, including Self-Schedules, in the Day-Ahead Market and the quantity ultimately scheduled from Eligible Intermittent Resources may differ from the CAISO forecasted deliveries from the Eligible Intermittent Resources. The CAISO may adjust the forecasted Demand either up or down for such differences by RUC Zone in which the Eligible Intermittent Resource resides. If the EIR’s expected output participating in the Day-Ahead Market, as reflected in the EIR’s Bid, including a Self-Schedule, or lack thereof, is less than CAISO’s forecast of the EIR, the CAISO may make a Supply-side adjustment to the resource’s expected output by using the CAISO’s forecast of the EIR. If on the other hand, the EIR’s expected output participating in the Day-Ahead Market, as reflected in the EIR’s Bid, including a Self-Schedule, or lack thereof, is greater than the CAISO’s forecast of the EIR, the CAISO may make a Demand side adjustment to the RUC Zone Demand equal to the difference between the EIR’s Day-Ahead Schedule and the CAISO forecasted quantity.

**31.5.3.1.5 Real-Time Expected Incremental Supply Self-Schedule Adjustment**

In order to avoid over procurement of RUC, the CAISO shall, using a similar-day approach, estimate the RTM Self-Schedules for resources that usually submit RTM Self-Schedules that are greater than their Day-Ahead Schedules. The CAISO Operator may set the length of the Self-Schedule moving average window. Initially this moving average window shall be set by default to seven (7) days; in which case the weekday estimate is based on the average of five (5) most recent weekdays and the weekend estimate is based on the average of the two (2) most recent weekend days. To the extent weather conditions differ significantly from the historical days, additional adjustment may be necessary. After determining the estimate of Real-Time Self-Schedules, using a similar day forecasting approach, the CAISO adjusts the CAISO Forecast of BAA Demand of a RUC Zone based on the forecasted quantity changes in Supply as a result of Self-Schedules submitted in the RTM. This adjustment for forecasted Real-Time Self- Schedules may result in positive or negative adjustments. Demand adjustments to the CAISO Forecast of BAA Demand result when there is a net forecast decrease in Real-Time Self-Schedule Supply relative to the Day-Ahead Schedule Supply. Supply adjustments to the individual resources occur when there is a net forecast increase in Real-Time Self-Schedule Supply relative to the Day-Ahead Schedule Supply of the individual resource.

**31.5.3.1.6 Day-Ahead Ancillary Service Procurement Deficiency Adjustment**

While the CAISO intends to procure one hundred percent (100%) of its forecasted Operating Reserve requirement in the IFM based on the CAISO Forecast of BAA Demand as specified in Section 8.3.1, the CAISO shall make adjustments to the CAISO Forecast of BAA Demand used in RUC to ensure sufficient capacity is available or resources committed in cases that the CAISO is unable to procure one hundred percent (100%) of its forecasted Operating Reserve requirement in the IFM; provided, however, that the CAISO shall not procure specific Ancillary Services products in RUC, nor will the RUC optimization consider AS-related performance requirements of available capacity.

**31.5.3.2 RUC Zones**

**31.5.3.2.1 Use of RUC Zones**

The CAISO shall adjust the CAISO Forecast of BAA Demand by RUC Zone for the conditions described in Sections 31.5.3.2 through 31.5.3.6. If any adjustments are made throughout the affected RUC Zone, such adjustments will be made consistent with the subset of system LDFs for the Nodes that define the RUC Zone(s). The CAISO will adjust the CAISO Forecast of BAA Demand of each affected RUC Zone, preserving the LDFs within each RUC Zone, but the relative weighting of the LDFs across the system will deviate from the original LDFs.

**31.5.3.2.2 Designation of RUC Zones**

The CAISO shall define RUC Zones as areas that represent UDC or MSS Service Areas, Local Capacity Areas, or any other collection of Nodes. RUC Zones will be designated by the CAISO as necessary and to the extent that the CAISO has developed sufficient data on historical Demand in a BAA and weather conditions to allow it to perform Demand Forecasts. Once the CAISO has established RUC zones, the mapping of RUC Zones to Nodes shall be static data and shall be maintained in the Master File. The CAISO may add new Nodes to a RUC Zone if new Nodes are added to the FNM. The status of each RUC Zone shall remain active for as long as the CAISO maintains regional forecasting capabilities, but once a RUC Zone is designated the CAISO will only adjust the CAISO Forecast of BAA Demand as necessary to address RUC procurement constraints and not as a normal course for all CAISO Market functions. The actual RUC Zones used by the CAISO in its operation of RUC are posted on the CAISO Website.

### 31.5.4 RUC Procurement Constraints

In addition to the resource constraints and Transmission Constraints employed by SCUC as discussed in Section 27.4.1, the CAISO shall employ the following three constraint in RUC:

(a) To ensure that sufficient RUC Capacity is procured to meet the CAISO Forecast of BAA Demand, the CAISO will enforce the power balance between the total Supply, which includes Day-Ahead Schedules and RUC Capacity, and the total Demand, which includes the CAISO Forecast of BAA Demand and IFM export Schedules. The CAISO may adjust the CAISO Forecast of BAA Demand to increase the RUC procurement target if there is AS Bid insufficiency in the IFM.

### 31.5.5 Selection and Commitment of RUC Capacity

Capacity that is not already scheduled in the IFM may be selected as RUC Capacity to meet a RUC Procurement Target.

**31.5.5.1 Nodal Procurement and Deliverability of Reliability Capacity**

RUC optimizes procurement of Reliability Capacity such that, in the event the Real-Time Market awards the incremental or decremental Energy Bids corresponding to the Reliability Capacity Awards, the dispatch of Energy from the Reliability Capacity in the market would not result in flows exceeding Transmission Constraints and scheduling limits, including EDAM Transfer limits.

The RUC optimization distributes an EDAM Entity’s RUC procurement target to the Demand Locations within each EDAM Entity based on distribution factors derived from historical and/or forecasted information that reflect the relative contributions of Demand to the RUC procurement targets.

**31.5.5.2 The RUC Optimization**

The RUC optimization will select RUC Capacity and produce nodal RUC Prices by minimizing total Bid cost based on RUC Availability Bids and Start-Up, Minimum Load Bids and Transition Costs. RUC will not consider Start-Up, Minimum Load Bids, or Transition Costs for resources already committed in the IFM. The CAISO will only issue RUC Start-Up Instructions to resources committed in RUC that must receive a Start-Up Instruction in the Day-Ahead in order to be available to meet Real-Time Demand. RUC Schedules will be provided to Scheduling Coordinators even if a RUC Start-Up Instruction is not issued at that time. RUC shall not Shut Down resources scheduled through the IFM but RUC may commit a Multi-Stage Generating Resource to a lower MSG Configuration. If the RUC process cannot find a feasible solution given the resources committed in the IFM, the RUC process will adjust constraints as described in Section 31.5.4 to arrive at a feasible solution that accommodates all the resources committed in the IFM, and any necessary de-commitment of IFM committed units shall be effectuated through an Exceptional Dispatch.

**31.5.5.3 Limitations on RUC Awards**

A RUC Award is limited to a resource’s 60-minute ramp capability. A RUC Award to a specific resource only can consist of RCU or RCD, and not both. RUC shall not Shut Down resources scheduled through the IFM. RUC shall not provide a RUC Award to a Multi-Stage Generating Resource that would require it to make an infeasible transition from the MSG Configuration applicable to its Day-Ahead Schedule to the MSG Configuration applicable to meeting the requirements of the potential RUC Award.

The RUC optimization applies a capacity constraint such that the sum of awards for Energy, upward Ancillary Services, IRU, and RCU does not exceed the resource’s Upper Economic Limit or, in the case of an Eligible Intermittent Resource, the forecasted output based on the forecast referenced in Section 4.8.2.1.

The RUC optimization only awards a RUC Award to a storage resource using the Non-Generator Resource model to the extent its modeled state of charge can support such schedule or award.

### 31.5.6 Eligibility for RUC Compensation

All RUC Capacity is eligible for the RUC Availability Payment except for: (i) RMR Capacity from RMR Resources; (ii) RUC Capacity resulting from RUC Availability Bids for exports inserted pursuant to Section 31.5.1.5;

and (iii) RUC Capacity that corresponds to the resource’s Minimum Load, which is compensated through the Bid Cost Recovery as described in Section 11.8. Resources not committed in the IFM that are committed in RUC, including Condition 1 Legacy RMR Units that were not designated for RMR Dispatches and Resource Adequacy Resources, are also eligible for RUC Cost Compensation, which includes Start-Up, Transition Costs, and Minimum Load Cost compensation, and Bid Cost Recovery, subject to the resource actually following its Dispatch Instructions as verified by the CAISO pursuant to procedures set forth in the Business Practice Manuals.

### 31.5.7 Rescission of Payments for RUC Capacity

If capacity committed in RUC provided from a Generating Unit, Participating Load, Proxy Demand Resource, System Unit or System Resource is Undispatchable Capacity during the relevant Settlement Interval, then the CAISO rescinds the payments as described in this Section 31.5.7 and settled in accordance with Section 11.2.2.2. If the CAISO determines that non-compliance of a Participating Load, Proxy Demand Resource, Generating Unit, System Unit or System Resource with an Operating Instruction or Dispatch Instruction from the CAISO, or with any other applicable technical standard under the CAISO Tariff, causes or exacerbates system conditions for which the WECC imposes a penalty on the CAISO, then the Scheduling Coordinator of such Participating Load, Proxy Demand Resource, Generating Unit, System Unit or System Resource shall be assigned that portion of the WECC penalty which the CAISO reasonably determines is attributable to such non-compliance, in addition to any other penalties or sanctions applicable under the CAISO Tariff. The rescission of payments in this Section 31.5.7 shall not apply to a capacity payment for any particular RUC Capacity if the RUC Availability Payment is less than or equal to zero (0).

### 31.5.8 RTM Bidding Obligations from RUC Awards

A RUC Availability Award in an hour obligates the Scheduling Coordinator for the resource receiving the award to submit Economic Bids to the Real-Time Market for the full range of awarded Reliability Capacity.

The portion of the resource’s Day-Ahead Schedule for Energy below a RCD award may be Self-Scheduled in the Real-Time Market.

A resource receiving a RUC Availability Award in an hour cannot submit a Self-Schedule for Energy in the Real-Time Market for a quantity in excess of its Day-Ahead Schedule for Energy minus any awards for IRD and RCD.

Resources receiving a RUC Availability Award for RCU that has submitted an Energy Bid in the Day-Ahead Market to export outside the EDAM Area must provide a decremental Energy Bid to dispatch down the export schedule in the FMM if needed.

By forty minutes prior to the applicable Trading Hour, a System Resource receiving a RUC Award must submit an E-Tag (or set of E-Tags) that passes CAISO E-Tag validation procedures, with the quantity (or sum of quantities) of the transmission profile no less than the sum of the RUC Award and any Day-Ahead Schedule for Energy. Failure to meet this deadline results in the CAISO deeming the entire quantity of the RUC Award as Undispatchable Capacity for RUC for purposes of Section 11.2.2.2.1.

## 31.6 Timing of Day-Ahead Scheduling

### 31.6.1 Criteria for Temporary Waiver of Timing Requirements

The CAISO may at its sole discretion implement any temporary variation or waiver of the timing requirements of this Section 31 and Section 6.5.3 (including the omission of any step) if any of the following criteria are met:

(i) such waiver or variation of timing requirements is reasonably necessary to preserve System Reliability, prevent an imminent or threatened System Emergency or to retain Operational Control over the CAISO Controlled Grid during an actual System Emergency.

(ii) because of error or delay, the CAISO requires additional time to fulfill its responsibilities;

(iii) problems with data or the processing of data cause a delay in receiving or issuing Bids or publishing information on the CAISO’s secure communication system;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Day-Ahead Schedules or publishing information on the CAISO’s secure communication system; or

(v) additional time is needed to allow for the submission of Bids in the event that the conditions specified in Section 30.5.8 change prior to the Market Close, and may require the resubmission of Bids consistent with the changed bidding requirements.

### 31.6.2 Information to be Published on Secure Communication System

If the CAISO temporarily implements a waiver or variation of such timing requirements, the CAISO will publish the following information on the CAISO’s secure communication system as soon as practicable:

(i) the exact timing requirements affected;

(ii) details of any substituted timing requirements;

(iii) an estimate of the period for which this waiver or variation will apply; and

(iv) reasons for the temporary waiver or variation.

### 31.6.3 Conditions Permitting CAISO to Abort Day-Ahead Market

If, despite the variation of any time requirement or the omission of any step, the CAISO either fails to receive sufficient Bids or fails to clear the Day-Ahead Market, the CAISO may abort the Day-Ahead Market and require all Bids to be submitted in the RTM.

### 31.6.4 [Not Used]

## 31.7 Extremely Long-Start Commitment Process

The CAISO shall perform the Extremely Long-Start Commitment Process (ELC Process) after the regular DAM results are posted. ELS Resources are flagged in the Master File and are the only resources eligible to be committed in the ELC Process. Each day after the DAM results are posted, the CAISO shall conduct the ELC Process to determine commitment of ELS Resources to be available to the CAISO Markets in the second day out. The CAISO will use the latest CAISO Forecast of CAISO Demand available to the CAISO for the Trading Day two days ahead of the current day that the ELC Process is executed. For commitment purposes for a resource whose Start-Up Time would exceed the definition of an ELS Resource based on the resource’s initial condition and cooling time, the CAISO will consider DAM Bids from ELS Resources as Bids for the Trading Day two days ahead of the current day that the ELC Process is executed. The CAISO Operator shall use its operator judgment consistent with Good Utility Practice to determine whether ELS Resources for the second day in the 48-hour time period should be committed. The ELC Process does not dispatch Energy for the 48-hour time period and therefore the commitment instructions will not include megawatts schedules greater than the Minimum Load. ELS Resources receiving a commitment instruction are obligated to resubmit the same Bid in the next day’s Day-Ahead Market. The CAISO Commitment Period or Self-Commitment Period determination for the ELS Resources depends on the DAM results and the Clean Bids and Generated Bids, following the same rules that apply to other resources. All Commitment Intervals for the ELS Resources will be classified as CAISO Commitment Periods, unless there is a Self-Schedule or Self-Provided AS for that interval.

## 31.8 Constraints Enforced at Interties

### 31.8.1 Scheduling Constraints

Within the IFM and RTM optimizations, the CAISO enforces a constraint at each CAISO Intertie such that physical imports net of physical exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. The CAISO incorporates the Shadow Price of this IFM constraint into the CAISO Market runs used to establish LMPs for both physical and virtual awards. Within the RUC process, the CAISO enforces a constraint at each Intertie such that physical imports net of physical exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. Through this RUC constraint the CAISO determines what Day-Ahead Schedules can have an E-Tag submitted Day-Ahead. Day-Ahead Schedules precluded from submitting an E-Tag in the Day-Ahead on this basis are exempt from the charges described in Section 11.32.

### 31.8.2 Physical Flow Constraints

The CAISO may enforce a physical flow constraint limit at each internal and Intertie location in the IFM taking into account the total power flow contributions, which include internal schedules, which can be physical or virtual, import/export schedules, and the CAISO’s estimates of unscheduled flow at the Interties. The physical flow constraint limit at each Intertie is less than or equal to the Transmission Constraints, including Nomograms and Contingencies, affecting the Intertie. At each Intertie the scheduling and physical flow constraint limits may differ. In the RUC and RTM processes, the same physical flow constraint limit is applied and internal schedules and import/export schedules, which can only be physical, are considered along with the CAISO’s estimates of unscheduled flow at the Interties. The CAISO will not enforce physical flow constraints at Interties for which the CAISO (1) is subject to contractual arrangements that provide for the management of unscheduled flows using other procedures; (2) has determined it cannot enforce the power flow constraints due to modeling inaccuracies, including inaccuracies in available data; or (3) has otherwise determined that enforcing the power flow constraints could result in adverse reliability impacts.

## 31.9 RUC MPM Process

After the IFM and prior to RUC, the CAISO performs the RUC MPM.

### Determining Competitive and Non-Competitive Congestion Components in RUC

The RUC MPM process produces potential RUC Availability Awards by enforcing all Transmission Constraints that are expected to be enforced in procuring Reliability Capacity to meet the CAISO Forecast of BAA Demand, with that forecast distributed to Demand Locations based on Load Distribution Factors, and based on unmitigated RUC Availability Bids. The RUC MPM uses as the Reference Bus either: (1) the Midway 500kV bus if Path 26 flow is from north to south; or (2) the Vincent 500kV bus if Path 26 flow is from south to north. The treatment of a particular Transmission Constraint as competitive or non-competitive for purposes of the RUC MPM process is determined pursuant to Section 39.7.2.

### 31.9.2 RUC Bid Mitigation

The CAISO applies Local Market Power Mitigation to Bids for RCU if the resource for which that Bid was submitted could provide counter-flow to a Transmission Constraint deemed non-competitive pursuant tothe methodology outlined in Section 39.7.2.2(B)(a) in the case of modeling the dispatch of Energy for the capacity corresponding to RCU Awards. To the extent a Bid for RCU is subject to Local Market Power Mitigation and exceeds the Competitive RCU LMP plus the Competitive LMP Parameter, the CAISO mitigates the Bid to the higher of the: (i) resource’s RCU Default Availability Bid; or (ii) Competitive RUC Price for RCU plus the Competitive LMP Parameter.

The CAISO does not mitigate RUC Availability Bids for RCD and does not mitigate RUC Availability Bids for RCU submitted on behalf of imports from outside the EDAM Area.

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# 34. Real-Time Market

The CAISO conducts the Real-Time Market on any given Operating Day in which Scheduling Coordinators may submit Bids, and the CAISO commits and Dispatches Energy and procures Energy and Ancillary Services. The Real-Time Market consists of the following processes: (1) the Hour-Ahead Scheduling Process, (2) Real-Time Unit Commitment (RTUC), (3) the Short-Term Unit Commitment (STUC), (4) the Fifteen Minute Market (FMM), and (5) the Real-Time Dispatch (RTD).

The CAISO shall dispatch all resources, including Participating Load and Proxy Demand Resource, pursuant to submitted Bids or pursuant to the provisions below on Exceptional Dispatch.

## 34.1 Inputs to the Real-Time Market

The CAISO utilizes the following data and information as inputs in conducting the Real-Time Market:

### 34.1.1 Day-Ahead Market Results as Inputs to the Real-Tie Market

All of the Real-Time Market processes utilize results produced by the Day-Ahead Market for each Trading Hour of the Trading Day, including the combined commitments contained in the Day-Ahead Schedules, Day-Ahead Ancillary Services Awards, and RUC Awards. These DAM results are inputs to the RTM. The transactions associated with DAM results are settled based on the relevant DAM prices, and are not deemed performed in the Real-Time Market.

### 34.1.2 Market Model and System Information

The CAISO utilizes the Base Market Model used in the Day-Ahead Market and adjusted as described in 27.5.1 and 27.5.6, and other system information provided through the State Estimator output, resource outage and derate/rerate information in conducting all of the Real-Time Market processes. Updates to the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 used in all of the Real-Time Market processes include current estimates of real-time unscheduled flow at the Interties. The CAISO utilizes the most up-to-date Base Market Model and system information throughout the Real-Time Market processes to the extent feasible.

### 34.1.3 Bids in the Real-Time Market

Scheduling Coordinators may submit Bids, including Self-Schedules, for Supply that the CAISO shall use for the Real-Time Market, starting from the time Day-Ahead Schedules are posted, which is approximately 1:00 p.m., unless the posting of the Day-Ahead Market results are delayed for reasons specified in Section 31.6, until seventy-five (75) minutes prior to each applicable Trading Hour in the Real-Time. Scheduling Coordinators can submit Bids in the form of: (1) an Economic Bid for a Schedule in the RTM; (2) a Self-Schedule for acceptance to the RTM; (3) a Self-Schedule Hourly Block for acceptance in the HASP; (4) a Variable Energy Resource Self-Schedule for the RTM; (5) an Economic Hourly Block Bid for acceptance in the HASP; or (6) an Economic Hourly Block Bid with Intra-Hour Option for acceptance in the HASP and the FMM. This includes Self-Schedules by Participating Load that is modeled using the Pumped-Storage Hydro Unit. Scheduling Coordinators may not submit Bids, including Self-Schedules, for CAISO Demand in the RTM. Scheduling Coordinators may submit Bids, including Self-Schedules, for exports at Scheduling Points in the RTM. The rules for submitted Bids specified in Section 30 apply to Bids submitted to the RTM. Scheduling Coordinators may not submit Virtual Bids to the Real-Time Market, although Virtual Awards from the DAM are settled for their liquidated positions based on prices from the FMM. In the case of Multi-Stage Generating Resources, the RTM procedures will optimize Transition Costs in addition to the Start-Up Costs and Minimum Load Costs. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, all of the RTM processes will consider the Start-Up Cost, Minimum Load Cost, and Transition Cost associated with any Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration.

### 34.1.4 Real-Time Validation of Schedules and Bids

After the Market Close of the Real-Time Market, the CAISO performs a validation process consistent with the provisions set forth in Section 30.7 and the following additional rules. The CAISO will insert a Generated Bid to cover any RUC Award or Day-Ahead Schedule in the absence of any Self-Schedule or Economic Bid components, or to fill in any gaps between Bid components to cover a RUC Award or Day-Ahead Schedule for use in the RTM. Schedules and Bids submitted to the RTM to supply Energy and Ancillary Services will be considered in the various RTM processes, including the MPM process, the HASP, the STUC, the RTUC, the FMM and the RTD.

**34.1.5 Mitigating Bids in the RTM**

**34.1.5.1 Generally**

After the Market Close of the RTM, after the CAISO has validated the Bids pursuant to Section 30.7 and Section 34.1.4, and prior to conducting any other RTM processes, the CAISO conducts a MPM process. The results are used in the RTM optimization processes. Bids on behalf of Demand Response Resources, Participating Load, and Hybrid Resources are considered in the MPM process but are not subject to Bid mitigation. Energy storage resources whose PMax is less than five (5) MW are considered in the MPM process, but not subject to Bid mitigation. Bids from resources comprised of multiple technologies that include Non-Generator Resources will remain to be subject to all applicable market power mitigation under the CAISO Tariff, including Local Market Power Mitigation.

**34.1.5.2 Fifteen-Minute MPM**

The CAISO conducts the MPM process as the first pass of each fifteen-minute interval in the RTUC horizon starting with the unmitigated Bid set as validated pursuant to Section 30.7 and Section 34.1.4. The MPM process produces results for each fifteen-minute interval of the RTUC horizon and thus may produce mitigated Bids for any given resource for any fifteen-minute interval in the RTUC run horizon that applies to any CAISO Market Process that is based on a specific RTUC run. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each fifteen-minute interval of the RTUC run horizon, using the methodology set forth in Section 31.2.3 except that a resource may have a non-competitive Congestion component in a fifteen-minute interval based on a Transmission Constraint deemed non-competitive either in the base case for meeting Demand or in the separate cases of modeling the dispatch for Energy of all capacity awarded upward and downward Uncertainty Awards. If a Bid is mitigated in the MPM pass for a fifteen-minute interval in the RTUC run horizon, the mitigated Bid will be utilized in the corresponding binding HASP and FMM process for the fifteen-minute interval. If a Bid is not mitigated in a fifteen-minute MPM pass, the CAISO will still mitigate that Bid in subsequent fifteen-minute intervals of the RTUC horizon if the MPM pass for the subsequent intervals determine that mitigation is needed.

**34.1.5.3 Real-Time Dispatch MPM**

The RTD MPM process produces results for each five-minute interval of a Trading Hour. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each five-minute interval, using the methodology set forth in Section 31.2.3 except that a resource may have a non-competitive Congestion component in a five-minute interval based on a Transmission Constraint deemed non-competitive either in the base case for meeting Demand or in the separate cases of modeling the dispatch for Energy of all capacity awarded upward and downward Uncertainty Awards. The RTD MPM process is performed for a configurable number of RTD advisory intervals after the binding RTD interval, and the mitigated Bids are used in the corresponding RTD intervals of the following RTD.

**34.1.5.4 Reliability Must Run Resources**

For a Condition 1 Legacy RMR Unit, the use of RMR Proxy Bids is determined based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Section 31.2.3 above. If a Condition 2 Legacy RMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit’s Maximum Net Dependable Capacity will be considered in the MPM process. For both Condition 1 and Condition 2 Legacy RMR Units, when mitigation is triggered, a RMR Proxy Bid is calculated using the same methodology described above for non-RMR Units. For a Condition 1 Legacy RMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 Legacy RMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the Legacy RMR Unit’s Location, the resource will be flagged as an RMR Dispatch if it is dispatched pursuant to a Legacy RMR Contract at a level higher than the dispatch level determined by the Competitive LMP. Both Condition 1 and Condition 2 Legacy RMR Units may be issued manual RMR Dispatches at any time to address local reliability needs or to resolve non-competitive constraints.

**34.1.5.5 Competitive LMP Parameter**

When a Bid is mitigated, the CAISO will add a cost, not to exceed $0.01/MWh, to the Competitive LMP used in the MPM process prior to the DAM or RTM process. The CAISO will set the Competitive LMP Parameter as low as possible while creating a reasonable price separation between the area where mitigation applies and other areas where mitigation does not apply. The CAISO will publish the value of the Competitive LMP Parameter in the Business Practice Manual.

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# 39. Market Power Mitigation Procedures

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## 39.7 Local Market Power Mitigation for Energy Bids

Local Market Power Mitigation is based on the assessment and designation of Transmission Constraints as competitive or non-competitive pursuant to Section 39.7.2. The local market power mitigation processes are described in Section 31.2 for the DAM and Sections 34.1.5 for the RTM.

### 39.7.1 Calculation of Default Energy Bids

Default Energy Bids shall be calculated by the CAISO, for the on-peak hours and off-peak hours for both the DAM and RTMs, pursuant to one of the methodologies described in this Section. The Scheduling Coordinator for each Generating Unit owner or Participating Load must rank order the following options of calculating the Default Energy Bid starting with its preferred method. The Scheduling Coordinator must provide the data necessary for determining the Variable Costs unless the Negotiated Rate Option precedes the Variable Cost Option in the rank order, in which case the Scheduling Coordinator must have a negotiated rate established with the CAISO. If no rank order is specified for a Generating Unit or Participating Load, then the default rank order of (1) Variable Cost Option, (2) Negotiated Rate Option, (3) LMP Option will be applied. For the first ninety (90) days after changes to resource status and MSG Configurations as specified in Section 27.8.3, including the first ninety (90) days after the effective date of Section 27.8.3, the Default Energy Bid option for the resource is limited to the Negotiated Rate Option or the Variable Cost Option. Default Energy Bids used for purposes other than for calculating Reasonableness Thresholds will be subject to the Soft Energy Bid Cap, unless the CAISO has approved a Reference Level Change Request pursuant to Section 30.11 in support of an Energy Bid above the Soft Energy Bid Cap. Scheduling Coordinators for storage resources participating as Non-Generator Resources also may rank the storage resource option among their options. If no rank is specified for a storage resource participating as a Non-Generator Resource, then the default rank will be (1) Variable Cost Option and (2) LMP Option. Scheduling Coordinators for storage resources participating as Non-Generator Resources must provide the data necessary for determining the storage resource option if that option is the first in rank order.

**39.7.1.1 Variable Cost Option**

For natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by adding incremental cost (comprised of incremental fuel cost plus a volumetric Grid Management Charge adder plus a greenhouse gas cost adder if applicable) with the Variable Energy Operation and Maintenance Adder, by multiplying the sum by the Default Energy Bid Multiplier, adding a Bid Adder if applicable for a Frequently Mitigated Unit, and adding Variable Energy Opportunity Costs, if any. For non-natural gas-fueled units, the Variable Cost Option will calculate the Default Energy Bid by summing incremental fuel or fuel-equivalent cost plus a volumetric Grid Management Charge plus a greenhouse gas cost adder if applicable, multiplying the sum by the Default Energy Bid Multiplier, adding a Bid Adder if applicable for a Frequently Mitigated Unit, and adding Variable Energy Opportunity Costs, if any. For any Default Energy Bids calculated under the Variable Cost Option that exceed $1,000 per MWh because of an approved Reference Level Change Request, any ten percent (10%) adder or Frequently Mitigated Unit adder shall not exceed $100 per MWh.

**39.7.1.1.1 Incremental Cost Calculation Under the Variable Cost Option**

**39.7.1.1.1.1 Natural Gas-Fired Resources**

(a) Calculation of incremental fuel cost - For natural gas-fueled units, incremental fuel cost is calculated based on an incremental heat rate curve multiplied by the natural gas price calculated as described below.

Resource owners shall submit to the CAISO average heat rates (Btu/kWh) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average heat rate curve formed by the (Btu/kWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average heat rate pairs yield one (1) incremental heat rate segment that spans two (2) consecutive operating points. The incremental heat rates (Btu/kWh) in the incremental heat rate curve are calculated by converting the average heat rates submitted by resource owners to the CAISO to requirements of heat input (Btu/h) for each of the operating points and dividing the changes in requirements of heat input from one (1) operating point to the next by the changes in MW between two (2) consecutive operating points as specified in the Business Practice Manual. For each segment representing operating levels below eighty (80) percent of the unit’s PMax, the incremental heat rate is limited to the maximum of the average heat rates for the two (2) operating points used to calculate the incremental heat rate segment.

The unit’s final incremental fuel cost curve is calculated by multiplying this incremental heat rate curve by the applicable natural gas price, and then, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. Heat rate and cost curves shall be stored, updated, and validated in the Master File.

 (b) Calculation of greenhouse gas cost adder - For each natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, the CAISO will calculate a greenhouse gas cost adder as the product of the resource’s incremental heat rate, the greenhouse gas emissions rate authorized by the California Air Resources Board, and the applicable Greenhouse Gas Allowance Price.

 (c) Calculation of volumetric Grid Management Charge adder - For each natural gas-fired resource, the CAISO will include a volumetric Grid Management Charge adder that consists of: (i) the Market Services Charge; (ii) the System Operations Charge; and (iii) the Bid Segment Fee divided by the MW in the Bid segment.

**39.7.1.1.1.2 Non-Natural Gas-Fired Resources**

For non-natural gas-fueled units, incremental fuel cost is calculated based on an average cost curve as described below.

Resource owners for non-natural gas-fueled units shall submit to the CAISO average fuel or fuel equivalent costs ($/MW) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average cost curve formed by the ($/MWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average cost pairs yield one (1) incremental cost segment that spans two (2) consecutive operating points. For each segment representing operating levels below eighty percent (80%) of the unit’s PMax, the incremental cost rate is limited to the maximum of the average cost rates for the two (2) operating points used to calculate the incremental cost segment. The unit’s final incremental fuel cost curve is then adjusted, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing. The CAISO will include, if applicable: (i) greenhouse gas allowance costs for each non-natural gas-fired resource registered with the California Air Resources Board as having a greenhouse gas compliance obligation, as provided to the CAISO by the Scheduling Coordinator for the resource; (ii) variable operation and maintenance cost; and (iii) a volumetric Grid Management Charge adder that consists of: (a) the Market Services Charge; (b) the System Operations Charge; and (c) the Bid Segment Fee divided by the MW in the Bid segment. Cost curves shall be stored, updated, and validated in the Master File.

**39.7.1.1.1.3 Calculation of Natural Gas Price**

(a) The CAISO will use different gas price indices for the Day-Ahead Market and the Real-Time Market. If a gas price index is unavailable for any reason, the CAISO will use the most recent available gas price index as set forth in Section 39.7.1.1.1.3(c).

(b) For all Trading Days of the Day-Ahead Market, except for Mondays when the Monday-only gas price index is available and meets the liquidity criteria described below, the CAISO will calculate a gas price index based on natural gas commodity prices reported by the Intercontinental Exchange one (1) day prior to the applicable Trading Day between 8:00 a.m. and 9:00 a.m. Pacific Time for natural gas deliveries on the Trading Day. The natural gas commodity prices reported by the Intercontinental Exchange are volume-weighted average gas prices reported during its next-day trading window. For Monday Trading Days, the CAISO will use the Monday-only gas price index when it is reported by the Intercontinental Exchange three (3) days prior to the Monday Trading Day, provided:

(i) The historical average volume of the Monday-only gas price index at a given location, using no more than ninety (90) days of trading, is at least 25,000 MMBTUs based on the CAISO’s test of whether the volume at a given location is above 25,000 MMBTUs at least once every six (6) months; and

(ii) On any given day the Monday-only gas price index published at the locations that meet the requirement in subsection (b)(i) above represents at least five (5) transitions.

(c) For all Trading Days of the Real-Time Market, except for Mondays when the Monday-only gas price index is available and meets the liquidity criteria described below, the CAISO will calculate a gas price index using at least one (1) price from the following publications: Natural Gas Intelligence, SNL Energy/BTU’s Daily Gas Wire, or Platt’s Gas Daily. The CAISO will update the gas price indices for the Real-Time Market between 7:00 p.m. and 10:00 p.m. Pacific Time using the natural gas prices published one (1) day prior to the applicable Trading Day for natural gas deliveries on the Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published gas prices that are available. For Monday Trading Days, the CAISO will use the Monday-only gas price index when it is reported by the Intercontinental Exchange three (3) days prior to the Monday Trading Day, provided:

(i) The historical average volume of the Monday-only gas price index at a given location, using no more than ninety (90) days of trading, is at least 25,000 MMBTUs based on the CAISO’s test of whether the volume at a given location is above 25,000 MMBTUs at least once every six (6) months; and

(ii) On any given day the Monday-only index gas price published at the locations that meet the requirement in subsection(c)(i) above represents at least five (5) transactions.

**39.7.1.1.1.4 Calculation of Greenhouse Gas Allowance Price**

To calculate the Greenhouse Gas Allowance Price, the CAISO will average two prices from the following vendors: the Intercontinental Exchange and ARGUS. If a greenhouse gas price from a vendor is unavailable for any reason, the CAISO will use the most recent available greenhouse gas price from that vendor. If for any reason the CAISO cannot calculate a Greenhouse Gas Allowance Price, it will use the most recently calculated value. The CAISO will update the Greenhouse Gas Allowance Price by approximately 22:00 Pacific Time each day (T). The daily Greenhouse Gas Allowance Price will be used in the next day’s Real-Time Market (T+1) and in the Day-Ahead Market for the following Trading Day (T+2). The CAISO will calculate each Greenhouse Gas Allowance Price during a year using prices for greenhouse gas allowances from that same year.

**39.7.1.1.2 [Not Used]**

**39.7.1.1.3 Variable Energy Opportunity Costs Under the Variable Cost Option**

The CAISO will determine eligibility for Variable Energy Opportunity Costs for Use-Limited Resources pursuant to Section 30.4.6.

**39.7.1.2 LMP Option**

The CAISO will calculate the LMP Option for the Default Energy Bid as a weighted average of the lowest quartile of LMPs at the Generating Unit PNode in periods when the unit was Dispatched during the preceding ninety (90) day period for which LMPs that have passed the price validation and correction process set forth in Section 35 are available. The weighted average will be calculated based on the quantities Dispatched within each segment of the Default Energy Bid curve. Each Bid segment created under the LMP Option for Default Energy Bids will be subject to a feasibility test, as set forth in a Business Practice Manual, to determine whether there are a sufficient number of data points to allow for the calculation of an LMP based Default Energy Bid. The feasibility test is designed to avoid excessive volatility of the Default Energy Bid under the LMP Option that could result when calculated based on a relatively small number of prices.

**39.7.1.3 Negotiated Rate Option**

**39.7.1.3.1 Submission Process**

Scheduling Coordinators that elect the Negotiated Rate Option for the Default Energy Bid shall submit a proposed Default Energy Bid along with supporting information and documentation as described in a BPM. Within ten (10) Business Days of receipt, the CAISO will provide a written response. If the CAISO accepts the proposed Default Energy Bid, it will generally become effective within eleven (11) Business Days from the date of acceptance by the CAISO and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If the CAISO does not accept the proposed Default Energy Bid, the CAISO and the Scheduling Coordinator shall enter a period of good faith negotiations that terminates sixty (60) days following the date of submission of a proposed Default Energy Bid by a Scheduling Coordinator. If at any time during this period, the CAISO and the Scheduling Coordinator agree upon the Default Energy Bid, it will generally become effective within eleven (11) Business Days of the date of agreement and remain in effect until: (1) the Default Energy Bid is modified by FERC; (2) the Default Energy Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Default Energy Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If by the end of the sixty (60)-day period the CAISO and the Scheduling Coordinator fail to agree on the Default Energy Bid to be used under the Negotiated Rate Option, the Scheduling Coordinator has the right to file a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act.

During the sixty (60)-day period following the submission of a proposed negotiated Default Energy Bid by a Scheduling Coordinator, and pending FERC’s acceptance in cases where the CAISO fails to agree on the Default Energy Bid for use under the Negotiated Rate Option and the Scheduling Coordinator filed a proposed Default Energy Bid with FERC pursuant to Section 205 of the Federal Power Act, the Scheduling Coordinator has the option of electing to use any of the other options available pursuant to Section 39.7. If the Scheduling Coordinator does not elect to use any of the other options available pursuant to Section 39.7, or if sufficient data do not exist to calculate a Default Energy Bid using any of these options, the CAISO may establish a temporary Default Energy Bid as specified in Section 39.7.1.5.

Any negotiated Default Energy Bid for a resource that includes an opportunity cost component as of April 1, 2019, will remain in effect, subject to the CAISO’s renegotiation rights pursuant to Section 39.7.1.3.2.1, unless the Scheduling Coordinator pursues an Opportunity Cost pursuant to Section 30.4.6.1.2. If a Scheduling Coordinator pursues an Opportunity Cost pursuant to Section 30.4.6.1.2, the Scheduling Coordinator must either elect the Variable Cost Default Energy Bid or the CAISO will renegotiate the negotiated Default Energy Bid to, at a minimum, utilize the Variable Energy Opportunity Cost as a component of the negotiated Default Energy Bid in place of any previously negotiated Opportunity Cost value.

**39.7.1.3.2 Negotiated Values and Informational Filings**

**39.7.1.3.2.1 Renegotiation of Values**

The CAISO may require the renegotiation of any components including any Opportunity Costs negotiated pursuant to Section 30.4.6.3, any Default Energy Bids negotiated pursuant to this Section 39.7.1.3, or any temporary Default Energy Bids established pursuant to Section 39.7.1.5, that have become outdated, are possibly erroneous, or for which the Scheduling Coordinator has changed. In the renegotiation process, the CAISO may review and propose modifications to such values, and may require the Scheduling Coordinator to provide updated information to support continuation of such values.

**39.7.1.3.2.2 Informational Filings with FERC**

The CAISO shall make an informational filing with FERC of any Opportunity Costs calculated pursuant to Section 30.4.6.2 or negotiated pursuant to Section 30.4.6.3, any Default Energy Bids negotiated pursuant to this Section 39.7.1.3, or any temporary Default Energy Bids established pursuant to Section 39.7.1.5, no later than seven (7) days after the end of the month in which the Opportunity Cost or Default Energy Bid values were established.

**39.7.1.4 Frequently Mitigated Unit Option**

A Frequently Mitigated Unit that is eligible for a Bid Adder may select a fourth Default Energy Bid option, which is equal to the Variable Cost Option plus the Bid Adder as described in Section 39.7.

**39.7.1.5 Temporary Default Energy Bid**

If the Scheduling Coordinator does not elect to use any of the other options available pursuant to Section 39.7.1, or if sufficient data do not exist to calculate a Default Energy Bid using any of the available options, the CAISO will first seek to obtain from the Scheduling Coordinator any additional data required for calculating the Default Energy Bid options available pursuant to 39.7.1. If the provision of additional data by a Scheduling Coordinator results in additional or modified Default Energy Bid options pursuant to 39.7.1, the Scheduling Coordinator will have another opportunity to elect one of these options as its temporary Default Energy Bid. If the Scheduling Coordinator does not elect to use any of the options available pursuant to Section 39.7.1, or if sufficient data still do not exist to calculate a Default Energy Bid using any of the available options, the CAISO may establish a temporary Default Energy Bid based on one or more of the following: (1) operating cost data, opportunity cost, and other appropriate input from the Market Participant; (2) the CAISO’s estimated operating costs of the Electric Facility, taking the best information available to the CAISO; (3) an appropriate average of competitive Bids of one or more similar Electric Facilities; or (4) any of the other options for determining a Default Energy Bid for which data are available.

**39.7.1.6 Default Energy Bids for RMR Resources**

The Scheduling Coordinator for the RMR Resource must rank order its preferences between the Variable Cost Option and the Negotiated Rate Option, which shall be the default rank order if no rank order is specified by the Scheduling Coordinator. These preferences will be used to determine the Default Energy Bids for the capacity for each RMR Resource. RMR Units are not eligible to receive the ten percent adder under the Variable Cost Option pursuant to Section 39.7.1.1 or the Bid Adder pursuant to Section 39.8.

**39.7.1.7 Hydro Default Energy Bid**

Scheduling Coordinators may request a Hydro Default Energy Bid for a hydroelectric resource with storage capability located in the CAISO Balancing Authority Area or any EIM Entity Balancing Authority Area.

**39.7.1.7.1 Computation**

For each Trading Day, the CAISO will calculate the Hydro Default Energy Bid as the maximum of the (a) gas floor, (b) short-term component, and (c) long-term/geographic component, which are all calculated as specified below.

**39.7.1.7.1.1 Gas Floor**

The CAISO will calculate the gas floor as the most recent average heat rate for a typical gas turbine generator obtained from the Energy Information Administration, multiplied by the gas price for the fuel region applicable to the location of the hydroelectric resource, multiplied by 1.1.

**39.7.1.7.1.2 Short-Term Component**

The CAISO will calculate the short-term component as 1.4 multiplied by the maximum of:

(a) the day-ahead peak price at the applicable electric pricing hub;

(b) the on-peak balance of the month on peak futures price for the current month at the applicable electric pricing hub; and

(c) the on-peak monthly index on peak futures price at the applicable electric pricing hub for one (1) month after the current month.

**39.7.1.7.1.3 Long-Term/Geographic Component**

A Scheduling Coordinator may request that the long-term/geographic component be calculated based on multiple electric pricing hubs in addition to the default electric pricing hub consistent with Section 39.7.1.7.2.1. The CAISO will calculate the long-term/geographic component as 1.1 multiplied by the maximum of:

(a) the day-ahead on-peak price at the applicable electric pricing hub(s);

(b) the on-peak balance of the month futures prices for the current month at the applicable electric pricing hub(s); and

(c) the on-peak monthly index futures price at the applicable electric pricing hub(s) for all future months up to the maximum storage horizon after the current month.

**39.7.1.7.2 Requirements**

As part of its request for a Hydro Default Energy Bid, the Scheduling Coordinator must submit to the CAISO:

 (a) Annually, for each month of the upcoming year and for each electric pricing hub requested that is not the default electric pricing hub, the Scheduling Coordinator must (1) demonstrate that it holds firm transmission rights to enable delivery from the hydroelectric resource’s default market region to the requested electric pricing hub or to a delivery point that is similarly priced location; or (2) provide documentation that supports a historical practice of acquiring monthly firm transmission rights to the requested electric pricing hub(s) or similarly priced location. Scheduling Coordinators may demonstrate transmission rights to multiple locations and, based on the CAISO’s evaluation of such information, the CAISO may include multiple electric pricing hubs, in addition to the default electric pricing hubs, in the long-term/geographic component of the Hydro Default Energy Bid for the affected resources. The Scheduling Coordinator will attest through its submission that it reasonably expects it will be able to use the demonstrated transmission rights to deliver incremental sales from the hydroelectric resource because the rights are not fully committed and that there is an actual opportunity to use these rights. If the CAISO includes multiple electric pricing hubs in the long-term/geographic component, the Hydro Default Energy Bid calculation will use the maximum of the electric price indices published for each electric pricing hub as determined for each Trading Day. On Trading Days for which there are no relevant published electric price indices at an electric pricing hub, the CAISO will use the most recently published index for the applicable electric pricing hub.

(b) For resources that Scheduling Coordinators demonstrate a quantity of firm transmission rights to a requested electric pricing hub or similarly priced location that is less than the hydro resource’s capacity, the CAISO will include the requested electric pricing hub up to the quantity demonstrated transmission rights, and apply a proportional weighting of the resource’s transmission rights to calculate a weighted average of those bilateral electric pricing hub prices when calculating the value of the long-term/geographic component of the Hydro Default Energy Bid.

(c) In the absence of supporting transmission rights information when calculating the Hydro Default Energy Bid, the CAISO will revert to the default bilateral electric pricing hub specified in Section 39.7.1.7.3.

(d) If during the term of the annual period the Scheduling Coordinator no longer has the firm annual transmission rights previously demonstrated, or can no longer continue a historical practice of acquiring monthly firm transmission rights, the Scheduling Coordinator must inform the CAISO within five (5) Business Days of no longer holding such firm transmission rights.

(e) The CAISO may audit the Scheduling Coordinator and request additional information in support of the Scheduling Coordinator’s assertions.

(f) If the CAISO determines the Scheduling Coordinator has submitted inaccurate information, the CAISO may revert the resource to the default electric pricing hubs as specified in Section 39.7.1.7.3.

**39.7.1.7.2.2 Maximum Storage Horizon**

The maximum hydroelectric resource storage horizon submitted by the Scheduling Coordinator must:

 (a) Reflect the typical storage duration of a hydroelectric resource’s reservoir, defined as the length of time between which the reservoir cycles from a maximum elevation to a new maximum elevation during a hydro cycle. The Scheduling Coordinator shall compute the reservoir’s cycling time based on multiple years of reservoir elevation data.

(b) Be supported by (1) a written attestation by a representative who has the authority to bind the company stating that the value submitted to the CAISO as the maximum storage horizon is consistent with the requirements specified in Section 39.7.1.7.2.2 (a); or (2) corroborating information submitted to the CAISO, which may include several years of historic reservoir levels for the specific hydroelectric resource and regulatory filings related to the operations of the hydroelectric resource.

**39.7.1.7.3 Default Electric Pricing Hubs**

The default electric pricing hubs will be as specified in the Business Practice Manuals, which will also include a process for modifying or adding electric pricing hubs to the list of default electric pricing hubs.

**39.7.1.8 Storage Resource Option**

For storage resources participating as Non-Generator Resources, the storage resource option will calculate the Default Energy Bid by selecting the maximum of (1) the sum of the expected energy cost and the variable storage operation cost and, in the RTM, (2) the storage opportunity cost. The calculation is completed by adding ten percent (10%) to the value. To calculate the Default Energy Bid, the CAISO will use the PMin, PMax, Run Times, and other charging and discharging parameters registered in the Master File.

The expected energy cost represents the average cost to procure the amount of energy needed to charge the resource during the lowest-priced continuous block of time such that the resource can discharge completely, accounting for the resource’s charging duration and round-trip efficiency, and excluding losses. To calculate this component in the Day-Ahead Market, the CAISO will use the average price of Energy during the lowest priced hours based upon the final Energy Supply Bids from the MPM process at the relevant PNode, not to be below $0/MWh. To calculate this component in the Real-Time Market, the CAISO will use the average price of Energy during the lowest priced hours based upon the LMP from the IFM at the relevant PNode on the Trading Day, not to be below $0/MWh.

The variable storage operation cost represents the variable costs of operating a storage resource beyond its designed daily cycling range, submitted by the Scheduling Coordinator in $/MWh. The CAISO will validate the storage operation cost based on manufacturer warranty, available data, and supporting documentation submitted by the Scheduling Coordinator. The storage opportunity cost represents the opportunity cost of being dispatched during lower-priced RTM intervals, equal to the cost of Energy the resource could discharge during the highest-priced continuous RTM block, accounting for the resource’s discharge duration. To calculate this component in the Real-Time Market, the CAISO will use the lowest price of Energy during the highest priced period over which the resource could have discharged, based upon the LMP from the IFM at the relevant PNode on the Trading Day.

### 39.7.2 Competitive Path Designation

**39.7.2.1 Timing of Assessments**

For the DAM and RTM, the CAISO will make assessments and designations of whether Transmission Constraints are competitive or non-competitive as part of the MPM runs associated with the DAM and RTM, respectively. Only binding Transmission Constraints determined by the MPM process will be assessed in the applicable market.

**39.7.2.2 Criteria**

(A) Notwithstanding the provisions in Section 39.7.2.2(B), when the CAISO enforces the natural gas constraint pursuant to Section 27.11, the CAISO may deem selected internal constraints to be non-competitive for specific days or hours based on its determination that actual electric supply conditions may be non-competitive due to anticipated electric supply conditions in the Southern California Gas Company and San Diego Gas & Electric Company gas regions.

(B) Subject to Section 39.7.3, for the DAM and RTM, a Transmission Constraint will be non-competitive only if the Transmission Constraint fails the dynamic competitive path assessment pursuant to this Section 39.7.2.2.

(a) Transmission Constraints for the IFM - As part of the MPM process associated with the IFM, the CAISO separately evaluates Transmission Constraints for the base

scenario for meeting Demand, for the scenario of modeling the dispatch of Energy for the capacity corresponding to IRU Awards, and for the scenario of modeling the dispatch of Energy for the capacity corresponding to IRD Awards. The CAISO also evaluates Transmission Constraints for the scenario of modeling the dispatch of Energy for the capacity corresponding to RCU Awards. The CAISO will designate a Transmission Constraint for the DAM as non-competitive when the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(a):

(i) Counter-flow to the Transmission Constraint means the delivery of Power from a resource to the system load distributed reference bus. If counter-flow to the Transmission Constraint is in the direction opposite to the market flow of Power to the Transmission Constraint, the counter-flow to the Transmission Constraint is calculated as the shift factor multiplied by the resource’s scheduled Power. Otherwise, counter-flow to the Transmission Constraint is zero.

(ii) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers and all internal Virtual Supply Awards not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource’s Energy Bid adjusted for Self-Provided Ancillary Services and derates.

(iii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply and Virtual Supply Awards that provide counter-flow to the Transmission Constraint.

(iv) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint.

(v) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Section 4.5.1.1.12 and all effective internal Virtual Supply Awards of the Scheduling Coordinator and/or Affiliate. Effectiveness in supplying counter-flow is determined by scaling generation capacity and/or Virtual Supply Awards by the shift factor from that location to the Transmission Constraint being tested.

(vi) A portfolio of a net seller means any portfolio that is not a portfolio of a net buyer. A portfolio of a net buyer means a portfolio for which the average daily net value of Measured Demand minus Supply over a twelve (12) month period is positive. The average daily net value is determined for each portfolio by subtracting, for each Trading Day, Supply from Measured Demand and then averaging the daily value for all Trading Days over the twelve (12) month period. The CAISO will calculate whether portfolios are portfolios of net buyers in the third month of each calendar quarter and the calculations will go into effect at the start of the next calendar quarter. The twelve (12) month period used in this calculation will be the most recent twelve (12) month period for which data is available. The specific mathematical formula used to perform this calculation will be set forth in a Business Practice Manual. Market Participants without physical resources will be deemed to be net sellers for purposes of this Section 39.7.2.2(a)(vi).

(vii) In determining which Scheduling Coordinators and/or Affiliates control the resources in the three (3) identified portfolios, the CAISO will include resources and Virtual Supply Awards directly associated with all Scheduling Coordinator ID Codes associated with the Scheduling Coordinators and/or Affiliates, as well as all resources that the Scheduling Coordinators and/or Affiliates control pursuant to Resource Control Agreements registered with the CAISO as set forth Section 4.5.1.1.13. Resources identified pursuant to Resource Control Agreements will only be assigned to the portfolio of the Scheduling Coordinator that has control of the resource or whose Affiliate has control of the resource pursuant to the Resource Control Agreements.

(b) Transmission Constraints for the RTM - As part of the MPM processes associated with the RTM, the CAISO will designate a Transmission Constraint for the RTM as non-competitive when the sum of the supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint and the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(b):

(i) Counter-flow to the Transmission Constraint has the meaning set forth in Section 39.7.2.2(a)(i).

(ii) Supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint means the minimum available capacity from internal resources controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. The minimum available capacity for the current market interval will reflect the greatest amount of capacity that can be physically withheld. The minimum available capacity is the lowest output level the resource could achieve in the current market interval given its dispatch in the last market interval and limiting factors including Minimum Load, Ramp Rate, Self-Provided Ancillary Services, Ancillary Service Awards (in the Real-Time Market only), and derates.

(iii) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint that can be withheld. Counter-flow supply to the Transmission Constraint that can be withheld reflects the difference between the highest capacity and the lowest capacity of a resource’s Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute FMM interval or the preceding five (5) minute RTD interval, as applicable (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM. In determining whether to designate a Transmission Constraint as non-competitive for the RTM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of sixty (60) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval of the FMM. In determining whether to designate a Transmission Constraint as non-competitive for the FMM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of fifteen (15) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval.

(iv) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Sections 4.5.1.1.12 and 39.7.2.2(a)(vii). Effectiveness in supplying counter-flow is determined by scaling generation capacity by the shift factor from that location to the Transmission Constraint being tested.

(v) A portfolio of a net seller has the meaning set forth in Section 39.7.2.2(a)(vi).

(vi) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource’s Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute interval of the FMM or five (5) minute interval of the RTD, as applicable (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM.

(vii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply that provides counter-flow to the Transmission Constraint.

### 39.7.3 Default Competitive Path Designations

The CAISO will maintain default competitive path designation sets for the Day-Ahead Market and for the Real-Time Market, which the CAISO will use in order to determine the competitiveness or non-competitiveness of Transmission Constraints under two circumstances: (1) in the event of a failure of the CAISO Markets software to perform an assessment of whether Transmission Constraints are competitive or non-competitive pursuant to Section 39.7.2; and (2) in order to determine whether Exceptional Dispatches are related to a non-competitive Transmission Constraint for purposes of mitigation of Exceptional Dispatches of resources under Section 39.10(1). Default competitive path designations will be determined pursuant to the methodology set forth in this Section 39.7.3 and will be updated no less frequently than once every seven (7) days. Until the CAISO has developed sufficient information to develop default competitive path designations, the CAISO will continue to utilize the most recent list of competitive path designations determined prior to the effective date of this tariff provision.

**39.7.3.1 Methodology for Determining Day-Ahead Default Competitive Path Designations for Transmission Constraints other than Path 15 and Path 26 Transmission Constraints**

The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the Day-Ahead Market only if both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more hours of the days for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in seventy-five (75) percent or more of the instances in which the Transmission Constraint was binding when tested. These calculations will be made utilizing data from the Day-Ahead Market for the most recent sixty (60) Trading Days for which data is available. The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as non-competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.1(1) and 39.7.3.1(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

**39.7.3.2 Methodology for Determining HASP/RTM Default Competitive Path Designations for Transmission Constraints other than Path 15 and Path 26 Transmission Constraints**

The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the HASP/RTM only if both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more of the hours for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in seventy-five (75) percent or more of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the Real-Time Market for the most recent sixty (60) Trading Days for which data is available. If the Transmission Constraint was binding during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be binding for the entire hour. If the Transmission Constraint was determined to be non-competitive during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be non-competitive for the entire hour. The CAISO will designate a Transmission Constraint other than the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as non-competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.2(1) and 39.7.3.2(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

**39.7.3.3 Methodology for Determining Day-Ahead Competitive Path Designations for Path 15 and Path 26 Transmission Constraints**

The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the Day-Ahead Market unless both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more hours of the days for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in fewer than seventy-five (75) percent of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the MPM for the Day-Ahead Market for the most recent sixty (60) Trading Days for which data is available. The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.3(1) and 39.7.3.3(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

**39.7.3.4 Methodology for Determining RTM Default Competitive Path Designations for Path 15 and Path 26 Transmission Constraints**

The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the RTM unless both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more of the hours for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in fewer than seventy-five (75) percent of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the MPM for the Real-Time Market for the most recent sixty (60) Trading Days for which data is available. If the Transmission Constraint was binding during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be binding for the entire hour. If the Transmission Constraint was determined to be non-competitive during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be non-competitive for the entire hour. The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.4(1) and 39.7.3.4(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

### 39.7.4 Default Availability Bid for Imbalance Reserves and Reliability Capacity

The CAISO applies separate IRU Default Availability Bids and RCU Default Availability Bids.

A resource’s IRU Default Availability Bid is the higher of: (a) $55/MWh; or (b) the IRU Negotiated Availability Bid.

A resource’s RCU Default Availability Bid is the higher of: (a) $55/MWh; or (b) the RCU Negotiated Availability Bid.

A Scheduling Coordinator may choose to pursue both an IRU Negotiated Availability Bid and an RCU Negotiated Availability Bid.

**39.7.4.1 Process for Establishing an IRU or RCU Negotiated Availability Bid**

Scheduling Coordinators that elect the option of pursuing a Negotiated Availability Bid must submit a proposed value to apply either for IRU or RCU, depending on which type of Negotiated Availability Bid they have chosen to pursue. The proposed value must represent the costs of providing the underlying product. Within ten (10) Business Days of receipt, the CAISO will provide a written response. If the CAISO accepts the proposed Negotiated Availability Bid, it will generally become effective within eleven (11) Business Days from the date of acceptance by the CAISO and remain in effect until: (1) FERC modifies the Negotiated Availability Bid; (2) the CAISO and the Scheduling Coordinator modify the Negotiated Availability Bid by mutual agreement; or (3) the Negotiated Availability Bid expires, is terminated, or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If the CAISO does not accept the proposed Negotiated Availability Bid, the CAISO and the Scheduling Coordinator shall enter a period of good faith negotiations that terminates sixty (60) days following the date of submission of a proposed Negotiated Availability Bid by a Scheduling Coordinator. If at any time during this period, the CAISO and the Scheduling Coordinator agree upon the Negotiated Availability Bid, it will generally become effective within eleven (11) Business Days of the date of agreement and remain in effect as if the CAISO accepted it initially.

If by the end of the sixty (60)-day period the CAISO and the Scheduling Coordinator fail to agree on the Negotiated Availability Bid, the Scheduling Coordinator has the right to file a proposed Negotiated Availability Bid with FERC pursuant to Section 205 of the Federal Power Act.

During the sixty (60)-day period following the submission of a proposed Negotiated Availability Bid by a Scheduling Coordinator, and pending FERC’s acceptance in cases where the Scheduling Coordinator filed a proposed Negotiated Availability Bid with FERC pursuant to Section 205 of the Federal Power Act, the IRU Default Availability Bid or RCU Default Availability Bid for the resource is $55/MWh.

The CAISO may require the renegotiation of any Negotiated Availability Bids enacted pursuant to this Section 39.7.4.1 that have become outdated, are possibly erroneous, or for which the Scheduling Coordinator has changed. In the renegotiation process, the CAISO may review and propose modifications to such values, and may require the Scheduling Coordinator to provide updated information to support continuation of such values.

The CAISO shall make an informational filing with FERC of any Negotiated Availability Bids enacted pursuant to this Section 39.7.4.1 no later than seven (7) days after the end of the month in which the CAISO enacted the Negotiated Availability Bids.

**39.7.4.2 Transition Period for Negotiated Availability Bids**

The option to pursue a Negotiated Availability Bid will be unavailable until the CAISO certifies through a market notice it has gained sufficient operational experience with Imbalance Reserves and Reliability Capacity to validate that proposed Negotiated Availability Bids correspond reasonably to the underlying costs of providing the products. Such certification is deemed to have occurred if the CAISO does not issue the market notice within 18 months of the effective date of this Section 39.7.4.

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# 40. Resource Adequacy Demonstration for all SCs in the CAISO BAA

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## 40.6 Requirements for SCs and Resources for LSEs

This Section 40.6 does not apply to Resource Adequacy Resources of Load-following MSSs. Scheduling Coordinators supplying Resource Adequacy Capacity shall make the Resource Adequacy Capacity listed in the Scheduling Coordinator’s monthly Supply Plans under Section 40.4.7 available to the CAISO each hour of each day of the reporting month in accordance with this Section 40.6 and Section 9.3.1.3.

### 40.6.1 Day-Ahead Availability

Except as otherwise provided in Sections 40.6.1.1 and 40.6.4, Scheduling Coordinators supplying Resource Adequacy Capacity shall make such Resource Adequacy Capacity, available Day-Ahead to the CAISO as follows:

(1) Resource Adequacy Resources physically capable of operating must submit: (a) Economic Bids for Energy and/or Self-Schedules for all their Resource Adequacy Capacity and (b) Economic Bids for Ancillary Services and/or a Submission to Self-Provide Ancillary Services in the IFM for all of their Resource Adequacy Capacity that is certified to provide Ancillary Services. For Resource Adequacy Capacity that is certified to provide Ancillary Services and is not covered by a Submission to Self-Provide Ancillary Services, the resource must submit Economic Bids for each Ancillary Service for which the resource is certified. For Resource Adequacy Capacity subject to this requirement for which no Economic Energy Bid or Self-Schedule has been submitted, the CAISO shall insert a Generated Bid in accordance with Section 40.6.8. For Resource Adequacy Capacity subject to this requirement for which no Economic Bids for Ancillary Services or Submissions to Self-Provide Ancillary Services have been submitted, the CAISO shall insert a Generated Bid in accordance with Section 40.6.8 for each Ancillary Service the resource is certified to provide.

(2) Resource Adequacy Resources must be available except for limitations specified in the Master File, legal or regulatory prohibitions or as otherwise required by this CAISO Tariff or by Good Utility Practice.

(3) Through the IFM co-optimization process, the CAISO will utilize available Resource Adequacy Capacity to provide Energy, Imbalance Reserves, or Ancillary Services in the most efficient manner to clear the Energy market, manage congestion and procure required Ancillary Services. In so doing, the IFM will honor submitted Energy Self-Schedules of Resource Adequacy Capacity unless the CAISO is unable to satisfy one hundred percent (100%) of the Ancillary Services requirements. In such cases, the CAISO may curtail all or a portion of a submitted Energy Self-Schedule to allow Ancillary Service-certified Resource Adequacy Capacity to be used to meet the Ancillary Service requirements. The CAISO will not curtail for the purpose of meeting Ancillary Service requirements a Self-Schedule of a resource internal to a Metered Subsystem that was submitted by the Scheduling Coordinator for that Metered Subsystem. If the IFM reduces the Energy Self-Schedule of Resource Adequacy Capacity to provide an Ancillary Service, the Ancillary Service Marginal Price for that Ancillary Service will be calculated in accordance with Section 27.1.2 using the Ancillary Service Bids submitted by the Scheduling Coordinator for the Resource Adequacy Resource or inserted by the CAISO pursuant to this Section 40.6.1, and using the resource’s Generated Energy Bid to determine the Resource Adequacy Resource’s opportunity cost of Energy. If the Scheduling Coordinator for the Resource Adequacy Resource believes that the opportunity cost of Energy based on the Resource Adequacy Resource’s Generated Energy Bid is insufficient to compensate for the resource’s actual opportunity cost, the Scheduling Coordinator may submit evidence justifying the increased amount to the CAISO and to the FERC no later than seven (7) days after the end of the month in which the submitted Energy Self-Schedule was reduced by the CAISO to provide an Ancillary Service.

The CAISO will treat such information as confidential and will apply the procedures in Section 20.4 of this CAISO Tariff with regard to requests for disclosure of such information. The CAISO shall pay any higher opportunity costs approved by FERC.

(4) Resource Adequacy Resources must submit RUC Availability Bids for both RCU and RCD for their Resource Adequacy Capacity.

(5) Resource Adequacy Resources eligible to provide Imbalance Reserves must submit Bids for IRU and IRD for all RA Capacity that meets its obligation pursuant to 40.6.1(1)(a) by submitting an Economic Bid.

**40.6.1.1 Day-Ahead Availability - Specific RA Resource Types**

(a) **Distributed Generation Facilities.** Distributed Generation Facilities shall comply with the IFM and RUC bidding requirements that apply to the same technology type of a resource connected to the CAISO Controlled Grid.

(b) **Non-Generator Resources**

(1) Non-Generator Resources that do not use Regulation Energy Management shall submit:

(A) Economic Bids or Self-Schedules into the IFM for all RA Capacity for all hours of the month the resource is physically capable of operating; and

(B) RUC Availability Bids for both RCU and RCD for all RA Capacity for all hours of the month the resource is physically capable of operating,

(2) Non-Generator Resources using Regulation Energy Management shall submit Economic Bids or Self-Schedules into the IFM for all RA Capacity for Regulation for all hours of the month the resource is physically capable of operating.

(c) **Extremely Long-Start Resources.** Extremely Long-Start Resources that are Resource Adequacy Resources must make themselves available to the CAISO by complying with:

(1) the Extremely Long-Start Commitment Process under Section 31.7 or otherwise committing the ELS Resource upon instruction from the CAISO, if physically capable; and

(2) the applicable provisions of Section 40.6.1 regarding Day-Ahead availability for the Trading Days for which it was committed.

### 40.6.2 Real-Time Availability

(a) **General Requirement.** Except as otherwise provided in Section 40.6.4, for every Trading Hour in which a Resource Adequacy Resource receives a Day-Ahead Schedule for Energy, Imbalance Reserves, or Ancillary Services or a RUC Schedule, the Resource Adequacy Resource must submit Bids to the Real-Time Market for that Trading Hour that conform with the Resource Adequacy Resource’s obligations under Section 40.6.1 for the Day-Ahead Market. Provided, however, that any reference in Section 40.6.1 to RUC bidding does not apply to the Real-Time Market bidding obligations.

(b) **Short Start Units.** Irrespective of their Day-Ahead Schedule for Energy, Day-Ahead Schedule for Ancillary Services, or RUC Schedule, Short Start Units must, for each Trading Hour, submit Bids to the Real-Time Market that conform to their obligations under Section 40.6.1 for the Day-Ahead Market. Provided, however, that any reference in Section 40.6.1 to RUC bidding does not apply to the Real-Time Market bidding obligations for Short Start Units. The CAISO may waive these availability obligations for a resource that is not a Long Start Unit or an Extremely Long-Start Resource that does not have an Day-Ahead Schedule or a RUC Schedule based on a procedure to be published on the CAISO Website. The CAISO will insert Generated Bids in accordance with Section 40.6.8 for any Resource Adequacy Capacity subject to the above requirements for which the resource has failed to submit the appropriate bids to the RTM.

(c) **Long Start Units.** Long Start Units not committed in the Day-Ahead Market will be released from any further obligation to submit Self-Schedules or Bids for the relevant Operating Day. Scheduling Coordinators for Long Start Units are not precluded from self-committing the unit after the Day-Ahead Market and submitting a Self-Schedule or Wheeling-Out in the RTM, unless precluded by terms of their contracts.

(d) **Extremely Long-Start Resources.** Once an Extremely Long-Start Resource providing Resource Adequacy Capacity is committed by the CAISO, it shall comply, for the Trading Days for it was committed, with the Real-Time availability provisions in sub-sections (a) and (b) of this Section 40.6.2, including those provisions that otherwise apply only to Short Start Units.

(e) **Self-Schedules.** The CAISO will honor submitted Energy Self-Schedules of Resource Adequacy Capacity unless the CAISO is unable to satisfy one hundred (100) percent of its Ancillary Services requirements. In such cases, the CAISO may curtail all or a portion of a submitted Energy Self-Schedule to allow Ancillary Service-certified Resource Adequacy Capacity to be used to meet the Ancillary Service requirements, as long as such curtailment does not lead to a real-time shortfall in energy supply. If the CAISO reduces a submitted Real-Time Energy Self-Schedule for Resource Adequacy Capacity when that capacity is needed to meet an Ancillary Services requirement, the Ancillary Service Marginal Price for that capacity will be calculated in accordance with Sections 27.1.2 and 40.6.1.

(f) **Distributed Generation Facilities.** Distributed Generation Facilities shall comply with the RTM bidding requirements that apply to the same technology type of resource connected to the CAISO Controlled Grid.

(g) **Non-Generator Resources**

(1) Non-Generator Resources that do not use Regulation Energy Management shall submit –

(A) Economic Bids or Self-Schedules into the RTM for any remaining RA Capacity scheduled in the IFM or RUC; and

(B) Economic Bids or Self-Schedules into the RTM for all RA Capacity not scheduled in the IFM,

(2) Non-Generator Resources using Regulation Energy Management that are not Use-Limited Resources under Section 40.4.6.1 shall submit Economic Bids or Self-Schedules into the RTM for any remaining RA Capacity from resource scheduled in IFM or RUC.

### 40.6.3 [Not Used]

### 40.6.4 Availability Requirements for Resources with Operational Limitations that are not Qualified Use-Limits

**40.6.4.1 Must-Offer Obligation in DAM and RTM**

Conditionally Available Resources (irrespective of Use-Limited Resource qualification) and Run-of-River Resources that provide Resource Adequacy Capacity and that are physically capable of operating must submit Self-Schedules or Bids in the Day-Ahead Market for their expected available Energy or their expected as-available Energy, as applicable, in the Day-Ahead Market and RTM up to the quantity of Resource Adequacy Capacity the resource is providing. Such resources shall also revise their Self-Schedules or submit additional Bids in RTM based on the most current information available regarding Expected Energy deliveries.

An Eligible Intermittent Resource providing Resource Adequacy Capacity may, but is not required to, submit Bids in the Day-Ahead Market.

**40.6.4.2 RUC Availability Bids**

The following resource types providing Resource Adequacy Capacity are not required to submit RUC Availability Bids for that capacity: Pumping Load, Reliability Demand Response Resources, Combined Heat and Power Resources, Regulatory Must-Take Generation, Non-Generator Resources using Regulation Energy Management, Conditionally Available Resources, Run-of-River Resources, and Eligible Intermittent Resources.

**40.6.4.3 Ancillary Services Bids from Participating Loads that is Pumping Load**

The must-offer obligation for Participating Load that is Pumping Load is limited to submitting, for hours where underlying Load permits, Non-Spin Ancillary Services Bids and/or a Submission to Self-Provide Non-Spin Ancillary Services in the Day-Ahead Market for its Resource Adequacy Capacity that is certified to provide Non-Spinning Reserve Ancillary Service, and Economic Bids for Energy in the Real-Time Market for its Non-Spinning Reserve Capacity that receives an Ancillary Service Award in the Day-Ahead Market.

**40.6.4.4 Proxy Demand Resources**

(a) Short Start Proxy Demand Resources that provide Resource Adequacy Capacity shall submit RUC Availability Bids for all of their Resource Adequacy Capacity for all hours of the month the resource is physically available.

(b) Long Start Proxy Demand Resources are not required to submit Bids or Self Schedules in the RUC for their Resource Adequacy Capacity.

### 40.6.5 Additional Availability Requirements for System Resources

In the IFM, the multi-hour block constraints of a System Resource, other than a System Resource capable of submitting a Dynamic Schedule or a Resource-Specific System Resource, are honored in the optimization. Such a resource that is also a Resource Adequacy Resource must be capable of hourly scheduling by the CAISO in RUC if it is not fully scheduled in the IFM. If such a Resource Adequacy Resource is scheduled in the RUC, the CAISO will schedule the resource in the RTM for each hour of the resource’s RUC schedule without regard to the multi-hour block constraint that was submitted to the IFM. For an existing System Resource that provides Resource Adequacy Capacity through a call-option that expires prior to the close of the IFM, such a System Resource listed on a Resource Adequacy Plan must be reported to the CAISO for consideration in the Extremely Long-Start Commitment Process.

**40.6.5.1 Additional Availability Requirements for Dynamic and Non-Dynamic Resource-Specific System Resources**

A Dynamic or Non-Dynamic Resource-Specific System Resource that supplies Resource Adequacy Capacity, and is not otherwise a Use-Limited Resource, will be subject to the requirements of Sections 40.6.1 and 40.6.2.

**40.6.5.2 Dynamic Non-Resource Specific System Resources**

A Dynamic non-Resource-Specific System Resource that provides Resource Adequacy Capacity will be subject to the provisions of 40.6.1 and 40.6.2.

### 40.6.6 Requirement for Partial Resource Adequacy Resources

Only that output of a Resource Adequacy Resource that is designated by a Scheduling Coordinator as Resource Adequacy Capacity in its monthly or annual Supply Plan shall have an availability obligation to the CAISO. Exports being supported by non-Resource Adequacy Capacity from a Resource Adequacy Resource that becomes unavailable or unusable shall be considered as an export of non-Resource Adequacy Capacity. If a Resource Adequacy Resource goes on a Forced Outage, until the Scheduling Coordinator provides the information requested under section 9.3.10.3.2, the CAISO shall determine if the Scheduling Coordinator indicated under section 30.5.1 (aa) that capacity from its Resource Adequacy Resource is backing a Self-Schedule of exports at Scheduling Points explicitly sourced by non-Resource Adequacy Capacity. If the Scheduling Coordinator has indicated capacity from its Resource Adequacy Resource is backing a Self-Schedule of exports at Scheduling Points explicitly sourced by non-Resource Adequacy Capacity, the CAISO will allocate the derate pro rata between the RA Capacity and the remainder of the resource’s capacity up to its PMax.

### 40.6.7 [Not Used]

### 40.6.8 Use of Generated Bids

(a) **Day-Ahead Market.** Prior to completion of the Day-Ahead Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.1 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid for Energy, Reliability Capacity, and Ancillary Services and will insert a Generated Bid for such capacity into the CAISO Day-Ahead Market.

(b) **Real-Time Market.**  Prior to running the Real-Time Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.2 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the Real-Time Market.

(c) **Partial Bids for RA Capacity.** If a Scheduling Coordinator for an RA Resource submits a partial bid for the resource’s RA Capacity, the CAISO will insert a Generated Bid only for the remaining RA Capacity. In addition, the CAISO will determine if all dispatchable Resource Adequacy Capacity from Short Start Units, not otherwise selected in the IFM or RUC, is reflected in a Bid into the Real-Time Market and will insert a Generated Bid for any remaining dispatchable Resource Adequacy Capacity for which the CAISO has not received notification of an Outage.

(d) **Exemptions.** Notwithstanding any of the provisions of Section 40.6.8, for the following resource types providing Resource Adequacy Capacity, the CAISO only inserts a Bid in the Day-Ahead Market or Real-Time Market where the generally applicable bidding rules in Section 30 call for bid insertion: Use-Limited Resource, Non-Generator Resource, Variable Energy Resource, Hydroelectric Generating Unit (including Run-of-River resources), Proxy Demand Resource, Reliability Demand Response Resource, Participating Load, including Pumping Load, Combined Heat and Power Resource, Conditionally Available Resource, Non-Dispatchable Resource, and resources providing Regulatory Must-Take Generation.

(e) **NRS-RA Resources.** The CAISO will submit a Generated Bid in the Day-Ahead Market for a Non-Resource-Specific System Resource in each RAAIM assessment hour, to the extent that the resource provides Resource Adequacy Capacity subject to the requirements of Section 40.6.1 and does not submit an outage request or Bid for the entire amount of that Resource Adequacy Capacity. Aside from where the generally applicable bidding rules in Section 30 call for Bid insertion, the CAISO will not submit a Generated Bid in the Real-Time Market for a Non-Resource-Specific System Resource that fails to meet its bidding obligations under Section 40.6.2. A Bid inserted for the Real-Time Market pursuant to the generally applicable bidding rules in Section 30 may not necessarily cover the full Real-Time Market obligation under Section 40.6.2 and the resource may thus remain exposed to Non-Availability Charges.

(f) **Generated Bids for RUC.** The CAISO submits a Generated Bid for RUC Availability Bids for Resource Adequacy Resources for which a RUC Availability Bid was not submitted as required in Section 40.6.1(4). For RA Resources that submit a RUC Availability Bid for RCU with an insufficient quantity, the CAISO extends the quantity component of the Bid using the submitted price component of the Bid. For RA Resources that fail to submit any RUC Availability Bid for either RCU or RCD, the Generated Bid is for the required quantity with a $55 price component.

**40.6.8.1 Generated Bids for NRS-RA Resources**

Generated Bids to be submitted by the CAISO pursuant to Section 40.6.8 for Non-Resource-Specific System Resources that provide Resource Adequacy Capacity shall be calculated in accordance with this Section 40.6.8.1.

**40.6.8.1.1 Calculation Options for Generated Bids**

The Scheduling Coordinator for each Non-Resource-Specific System Resource that provides Resource Adequacy Capacity shall select the price taker option, LMP-based option, or negotiated price option as the methodology for calculating the Generated Bids to be submitted by the CAISO under Section 40.6.8 for both the DAM and RTMs. If no selection is made, the CAISO will apply the price taker option to calculate the Generated Bids. For the first ninety (90) days after a resource becomes a Non-Resource-Specific System Resource, the calculation of Generated Bids for Resource Adequacy capacity is limited to the price taker option or negotiated price option.

**40.6.8.1.2 Price Taker Option**

The price taker option is a Generated Bid of $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.

**40.6.8.1.3 LMP-Based Option**

The LMP-based option calculates the Generated Bid as the weighted average of the lowest quartile of LMPs, at the Intertie point designated for the Non-Resource-Specific System Resource’s Resource Adequacy Capacity in the Supply Plan, during periods in which the resource was dispatched in the preceding ninety (90) days for which LMPs that have passed the price validation and correction process set forth in Section 35 are available. The weighted average will be calculated based on the quantities Dispatched within each segment of the Generated Bid curve. Each Bid segment created under the LMP-based option for Generated Bids will be subject to a feasibility test, as set forth in a Business Practice Manual, to determine whether there are a sufficient number of data points to allow for the calculation of an LMP-based Generated Bid. The feasibility test is designed to avoid excessive volatility of the Generated Bid under the LMP-based option that could result when calculated based on a relatively small number of prices. If the Scheduling Coordinator for the Non-Resource-Specific System Resource elects the LMP-based method, it 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.

**40.6.8.1.4 Negotiated Price Option**

Under the negotiated price option, a Scheduling Coordinator shall submit a proposed Generated Bid along with supporting information and documentation as described in a Business Practice Manual. Within ten (10) Business Days of receipt, the CAISO will provide a written response. If the CAISO accepts the proposed Generated Bid, it will become effective within three (3) Business Days from the date of acceptance by the CAISO and remain in effect until: (1) the Generated Bid is modified by FERC; (2) the Generated Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Generated Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If the CAISO does not accept the proposed Generated Bid, the CAISO and the Scheduling Coordinator shall enter a period of good faith negotiations that terminates sixty (60) days following the date of submission of a proposed Generated Bid by a Scheduling Coordinator. If at any time during this period, and the Scheduling Coordinator agree upon the Generated Bid, it will be become effective within three (3) Business Days of the date of agreement and remain in effect until: (1) the Generated Bid is modified by FERC; (2) the Generated Bid is modified by mutual agreement of the CAISO and the Scheduling Coordinator; or (3) the Generated Bid expires, is terminated or is modified pursuant to any agreed upon term or condition or pertinent FERC order.

If by the end of the sixty (60) day period the CAISO and the Scheduling Coordinator fail to agree on the Generated Bid to be used under the negotiated price option, the Scheduling Coordinator has the right to file a proposed Generated Bid with FERC pursuant to Section 205 of the Federal Power Act.

During the sixty (60) day period following the submission of a proposed negotiated Generated Bid by a Scheduling Coordinator, and pending FERC’s acceptance in cases where the CAISO fails to agree on the Generated Bid for use under the negotiated price option and the Scheduling Coordinator filed a proposed Generated Bid with FERC pursuant to Section 205 of the Federal Power Act, the Scheduling Coordinator has the option of electing to use any of the other options available pursuant to this Section.

The CAISO shall make an informational filing with FERC of any Generated Bids negotiated pursuant to this Section no later than seven (7) days after the end of the month in which the Generated Bids were established.

**40.6.8.1.5 Partial Bids**

If a Scheduling Coordinator for a Non-Resource-Specific System Resource that provides Resource Adequacy Capacity submits a Bid for a MW quantity less than the Resource Adequacy Capacity identified in the resource’s Supply Plan, the CAISO will insert a Generated Bid only for the remaining Resource Adequacy Capacity by extending the last segment of the resource’s bid curve to the full quantity (MWh) of the Resource Adequacy obligation.

**40.6.8.1.6 [Not Used]**

### 40.6.9 Firm Liquidated Damages Contracts Requirements

Resource Adequacy Capacity represented by a Firm Liquidated Damages Contract and relied upon by a Scheduling Coordinator in a monthly or annual Resource Adequacy Plan shall be submitted as a Self-Schedule or Bid in the Day-Ahead IFM to the extent such scheduling right exists under the Firm Liquidated Damages Contract.

### 40.6.10 Exports of Energy from Resource Adequacy Capacity

Resource Adequacy Capacity may be utilized to serve an Export Bid. An Export Bid may be submitted into the CAISO Markets and be cleared by the Energy being provided by Resource Adequacy Capacity.

### 40.6.11 Curtailment of Exports in Emergency Situations

At its sole discretion, the CAISO may curtail exports from Resource Adequacy Capacity to prevent or alleviate a System Emergency. An Export Bid or a Self-Schedule to provide exports included in a binding Schedule accepted in the IFM or RTM will not be distinguished from a Demand Bid or Self-Schedule to serve Load within the CAISO Balancing Authority Area included in a binding Schedule accepted in the IFM or RTM for purposes of curtailment under this Section, except as consistent with Good Utility Practice.

### 40.6.12 Participating Load, PDRs, and RDRRs

Participating Loads, Reliability Demand Response Resources, or Proxy Demand Resources that are included in a Resource Adequacy Plan and Supply Plan, if the Scheduling Coordinator for the Participating Loads, Reliability Demand Response Resources, or Proxy Demand Resources is not the same as that for the Load Serving Entity or CPE, will be administered by the CAISO in accordance with the terms and conditions established by the CPUC or the Local Regulatory Authority.

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## 40.9 Resource Adequacy Availability Incentive Mechanism

### 40.9.1 Introduction to RAAIM

The CAISO shall use RAAIM to determine the availability of resources providing local and/or system Resource Adequacy Capacity and Flexible RA Capacity during the Availability Assessment Hours each month and then assess the resultant Availability Incentive Payments and Non-Availability Charges through the CAISO’s settlements process.

### 40.9.2 Exemptions

(a) **Capacity Exempt from RAAIM – All Provisions.** The entire capacity of a resource in any of the following categories is exempt from the RAAIM provisions in Section 40.9 –

(1) Resources with a PMax less than 1.0 MW;

(2) Non-specified resources that provide Resource Adequacy Capacity under contracts for Energy delivered within the CAISO Balancing Authority Area;

(3) Participating Load that is also Pumping Load; and

(4) Legacy RMR Units.

(b) **Capacity Exempt from RAAIM – Local/System**

(1) The entire capacity of a resource in any of the following categories is exempt from the RAAIM provisions in Section 40.9 applicable to local and system Resource Adequacy Capacity –

(A) Variable Energy Resources;

(B) Combined Heat and Power Resources; and

(C) Run-of-River Resources; and

(D) Hybrid Resources.

(2) The capacity of a resource with a Load-following MSS as its Scheduling Coordinator that is designated on a Load-following MSS’s monthly Resource Adequacy Plan is exempt from the RAAIM provisions in Section 40.9 applicable to local and system Resource Adequacy Capacity, to the extent that the resource’s capacity is also designated as Resource Adequacy Capacity on the monthly Supply Plan of that Load-following MSS or another Load-following MSS.

(3) Resources with Existing QF Contracts or Amended QF Contracts that are Resource Adequacy Resources are exempt from the RAAIM provisions in Section 40.9 applicable to local and system capacity --

(A) if the QF resource previously provided Resource Adequacy Capacity pursuant to an Existing QF Contract that was executed prior to August 22, 2010 and remained in effect pursuant to California Public Utilities Commission Decision 07-09-040 that extended the term of expiring contracts until such time as the new contracts resulting from that decision are available; or

(B) until the QF Resource’s Existing QF Contract or Amended QF Contract terminates or if requested by the Scheduling Coordinator for the resource, whichever is earlier.

(c) **Capacity Exempt from RAAIM – Flexible Capacity.**

(1) The capacity of Use-Limited Resources in a combination under Section 40.10.3.2(b), 40.10.3.3(b) or 40.10.3.4(b) is exempt from the RAAIM provisions in Section 40.9 applicable to Flexible RA Capacity to the extent that the resources are committed to provide Flexible RA Capacity as a combination on their respective monthly Supply Plans.

(2) The Capacity of a resource with a Load-following MSS as its Scheduling Coordinator that is designated on a Load-following MSS’s monthly Flexible RA Plan is exempt from the RAAIM provisions in Section 40.10 applicable to Flexible RA Capacity, to the extent that the resource’s capacity is also designated as Flexible RA Capacity on the monthly Supply Plan of that Load-following MSS or another Load-following MSS.

**40.9.2.1 Acquired Resources.**

(a) **Exemption.** The entire capacity of an Acquired Resource is exempt from the RAAIM provisions in Section 40.9 applicable to local and system Resource Adequacy Capacity if the resource provides Resource Adequacy Capacity under a resource-specific power supply contract that –

(1) was exempt from the prior standard capacity product in Section 40.9 as of the RAAIM effective date, and continues to meet the requirements for that exemption, under the provisions of Sections 40.9.2(1) or 40.9.2(2) contained in Appendix J.

(2) includes an availability provision, or the resource under the power supply contract is located outside of the CAISO Balancing Authority Area and jointly operated with project participants located outside of the CAISO Balancing Authority Area, such that no single Load Serving Entity with contractual rights for the resource’s output has the ability to effect changes to the resource’s availability; and

(3) does not contain a provision that allows the contract to be modified for regulatory changes.

(b) **Request.** To maintain the exemption, the Scheduling Coordinator for the Acquired Resource must annually request renewal of the exemption and –

(1) for Resource Adequacy Compliance Year 2016, submit an affidavit to the CAISO, by either the Scheduling Coordinator or resource owner, demonstrating that the Acquired Resource meets the eligibility criteria in Section 40.9.2.1(a), in accordance with the process and schedule in the Business Practice Manual; and

(2) for each Resource Adequacy Compliance Year thereafter until the contract terminates, submit confirmation to the CAISO that the information in the affidavit is still accurate and the Acquired Resource continues to meet the eligibility criteria in Section 40.9.2.1(a), in accordance with the process and schedule in Business Practice Manual.

(c) **Approval.** The CAISO shall review the information submitted and –

(1) approve a request that contains the information required by Sections 40.9.2.1(a) and (b) and that demonstrates the resource meets the eligibility criteria in Section 40.9.2.1(a);

(2) advise the Scheduling Coordinator for the resource if the request does not contain all of the information required by Sections 40.9.2.1(a) and (b), and allow the opportunity for the Scheduling Coordinator to submit the additional required information, in accordance with the process and schedule in the Business Practice Manual; or

(3) deny the request and permanently terminate the exemption if --

(A) the Scheduling Coordinator for the resource does not timely submit a request under Section 40.9.2.1(b);

(B) the Scheduling Coordinator for the resource does not submit, or does not timely submit, additional information required to complete the request under Section 40.9.2(c)(2); or

(C) the CAISO determines the resource does not meet the eligibility criteria in Section 40.9.2.1(a).

(d) **Failure to Request Renewal.** If the Scheduling Coordinator for the resource does not submit a request to renew the exemption under Section 40.9.2.1(b), the exemption shall terminate and the CAISO shall notify the Scheduling Coordinator of the termination in accordance with the process and schedule in Business Practice Manual.

(e) **Notice of Termination.** The Scheduling Coordinator for an Acquired Resource must notify the CAISO within 10 days if the contract terminates or no longer meets the eligibility criteria in Section 40.9.2.1(a).

### 40.9.3 Availability Assessment

**40.9.3.1 Local and System RA Capacity Availability**

(a) **Availability Assessment Hours**

(1) Prior to the start of each Resource Adequacy Compliance Year, the CAISO shall establish and publish in the Business Practice Manual the Availability Assessment Hours applicable for resources providing local and/or system Resource Adequacy Capacity for each month of that year.

(2) The Availability Assessment Hours shall be a pre-defined set of five consecutive hours for each month that –

(A) correspond to the operating periods when high demand conditions typically occur and when the availability of Resource Adequacy Capacity is most critical to maintaining system reliability:

(B) vary by season as necessary so that the coincident peak load hour typically falls within the five-hour range each day during the month, based on historical actual load data; and

(C) apply to each Trading Day that is a weekday and not a federal holiday.

(b) **Must-Offer Availability Assessment.** The CAISO shall determine the extent to which each resource providing local and/or system Resource Adequacy Capacity made that capacity available to the CAISO each day during the Availability Assessment Hours by comparing –

(1) the MWs of local and/or system Resource Adequacy Capacity for which the Scheduling Coordinator for the resource submitted Economic Bids or Self-Schedules in the Day-Ahead Market and the Real-Time Market on a given day; and

(2) the MWs of local and/or system Resource Adequacy Capacity for which the Scheduling Coordinator for the resource had a performance obligation to submit Economic Bids or Self-Schedules in the CAISO Markets under the must-offer requirements applicable under Section 40.6 on a given day, provided that Conditionally Available Resources will have RAAIM assessed as if the resource’s performance obligation were defined in Sections 40.6.1 and 40.6.2 and irrespective of their expected available Energy or their expected as-available Energy.

(3) The CAISO’s availability assessment under this Section 40.9.3.1 does not consider a RA Resource’s compliance with any Imbalance Reserves or Reliability Capacity bidding obligation it holds.

**40.9.3.2 Flexible RA Capacity Availability**

(a) **Availability Assessment Hours.** The Availability Assessment Hours for a Flexible RA Resource shall be the same period as the must-offer obligation for the Flexible Capacity Category that is designated on the Resource Flexible RA Capacity Plan for that month, as set forth in Section 40.10.6.

(b) **Must-Offer Availability Assessment.** The CAISO shall determine the extent to which each Flexible RA Resource made that capacity available in each Availability Assessment Hour of the day by comparing –

(A) the MWs of Flexible RA Capacity for which the Scheduling Coordinator for the resource submitted Economic Bids in the Day-Ahead Market and the Real-Time Market on a given day; and

(B) the MWs of Flexible RA Capacity for which the Scheduling Coordinator for the resource had a performance obligation to submit Economic Bids in the CAISO Markets under the must-offer requirements applicable under Section 40.10.6 on a given day.

(C) The CAISO’s availability assessment under this Section 40.9.3.2 does not consider a Flexible RA Resource’s compliance with any Imbalance Reserves or Reliability Capacity bidding obligation it holds.

(c) **Flexible Capacity Category.** If a Flexible RA Resource is designated to provide Flexible RA Capacity and/or RA Substitute Capacity in more than one Flexible Capacity Category on the same day, the CAISO will assess the availability of the resource using the must-offer obligation for the highest quality of Flexible Capacity Category designated.

(d) **Start-Up Less Than 90 Minutes.** For resources with a start-up time less than 90 minutes, the CAISO will use the resource’s MWs of capacity from zero to the EFC value to assess the availability of the designated Flexible RA Capacity; provided that the Scheduling Coordinator for the resource does not submit Self-Schedules for the capacity from zero to PMin or for any portion of the capacity under the must-offer obligation for Energy. If the Scheduling Coordinator for the resource submits a Self-Schedule, the CAISO will deduct the MW value of PMin from the calculation of the resource’s Flexible RA Capacity availability,

(e) **Start-Up Greater Than 90 Minutes.** For resources with a start-up time greater than 90 minutes, the CAISO will use the MWs of capacity between the resource’s PMin and EFC value in the availability assessment and validate whether the Scheduling Coordinator for the resource submitted Economic Bids for all MWs designated on the Resource Flexible RA Capacity Plan.

(f) **Variable Energy Resources**

(1) **Flexible RA Capacity Equal to EFC.** If the Flexible RA Capacity designated on the monthly Resource Flexible RA Capacity Plan is equal to the resource’s EFC value, the CAISO will assess the availability of the designated Flexible RA Capacity based on the Economic Bids for Flexible RA Capacity the Scheduling Coordinator for the resource submitted up to the MWs in the Variable Energy Resource forecast applicable under Section 4.8.2.

(2) **Flexible RA Capacity Less Than EFC.** If the Flexible RA Capacity designated in the monthly Resource Flexible RA Capacity Plan is less than the EFC value for the resource, the CAISO will assess availability using the ratio of the amount shown on the monthly plan to the relevant EFC value, and applies that ratio to the MWs of Economic Bids and the Variable Energy Resource forecast.

(3) **VER Forecast Less Than Flexible RA Capacity.** If the MWs in the Variable Energy Resource forecast are less than the MWs of Flexible RA Capacity designated in the monthly Resource Flexible RA Capacity Plan, and the Economic Bids are greater than or equal to the forecast amount for that hour, the resource is 100 percent available up to the forecast amount.

(4) **VER Forecast Greater Than Flexible RA Capacity.** If the MWs in the Variable Energy Resource forecast are greater than the MWs of Flexible RA Capacity designated in the monthly Resource Flexible RA Capacity Plan, the Scheduling Coordinator for the resource must submit Economic Bids equal to the forecast amount. If the Scheduling Coordinator for the resource submits Economic Bids for MWs above the forecast, or the resource generates above the forecast, the CAISO will limit the calculated availability to the forecast amount.

(5) **No Day-Ahead Market Obligation.** For Variable Energy Resources that do not have an obligation to submit Economic Bids into the Day-Ahead Market, the CAISO will base the availability assessment of the Flexible RA Capacity only on the resource’s Economic Bids in the Real-Time Market.

**40.9.3.3 Availability for Overlapping Local/System and Flexible RA Capacity**

(a) **Overlap Determination.** The availability assessment for overlapping Resource Adequacy commitments shall apply to those MWs subject to the must-offer obligations for local and/or system Resource Adequacy Capacity and Flexible RA Capacity in any Availability Assessment Hour. For the purpose of this Section 40.9, capacity is deemed to have an overlapping Resource Adequacy commitment if it has a must-offer obligation based on its status as local and/or system Resource Adequacy Capacity and a must-offer obligation based on its status as Flexible RA Capacity during the same Availability Assessment Hour of a day.

(b) **Must-Offer Availability Assessment.** The CAISO shall determine the extent to which each resource with overlapping Resource Adequacy commitments made that capacity available to the CAISO in each overlapping Availability Assessment Hour of the day by comparing –

(1) the MWs of local and/or system Resource Adequacy Capacity and Flexible RA Capacity for which the Scheduling Coordinator for the resource submitted Economic Bids in the Day-Ahead Market and the Real-Time Market; and

(2) the MWs of local and/or system Resource Adequacy Capacity and Flexible RA Capacity for which the Scheduling Coordinator for the resource had a performance obligation to submit Economic Bids in the CAISO Markets, in accordance with the applicable must-offer requirements in Sections 40.6 and 40.10.6.

(c) **Calculation.** The CAISO’s calculation of the Availability Assessment for overlapping RA commitments shall count-

(1) any MW only once; and

(2) the total MWs of overlapping capacity as a Flexible RA Capacity commitment.

**40.9.3.4 Treatment of Outages**

(a) **RA** **Substitute Capacity Not Required.** The RAAIM Availability Assessment for a Resource Adequacy Resource excludes the capacity, duration, and must-offer requirements for Resource Adequacy Capacity on an Outage during the Resource Adequacy month that does not require RA Substitution Capacity under Section 9.3.1.3.

(b) **RA** **Substitute Capacity Required and Provided.** For each Outage that requires RA Substitute Capacity under Section 40.9.3.6 to avoid imposition of RAAIM charges –

(1) the RAAIM Availability Assessment for the resource excludes the capacity, duration, and must-offer requirement for Resource Adequacy Capacity on outage to the extent the resource provides RA Substitute Capacity for that outage as required under Section 40.9.3.6; and

(2) the RAAIM Availability Assessment for the substitute resource includes the capacity, duration, and must-offer requirement for the RA Substitute Capacity commitment. For each day the substitute resource is committed to provide Flexible RA Capacity and/or RA Substitute Capacity in more than one Flexible Capacity Category, the RAAIM Availability Assessment applies the must-offer obligation for the highest quality Flexible Capacity Category to the total MWs of the flexible capacity requirement. For the purposes of this Section 40.9, base ramping resources (as defined in section 40.10.3.2) are considered to be a higher quality of Flexible Capacity Category than either peak ramping resources (as defined in section 40.10.3.3) or super-peak ramping resources (as defined in section 40.10.3.4). Additionally, peak ramping resources (as defined in section 40.10.3.3) are considered to be a higher quality of Flexible Capacity Category than super-peak ramping resources (as defined in section 40.10.3.4).

(c) **RA Substitute Capacity Required not Provided.**  For each Outage that requires RA Substitute Capacity under Section 40.9.3.6 to avoid imposition of RAAIM charges, the RAAIM Availability Assessment for the resource includes the capacity, duration, and must-offer requirement for Resource Adequacy Capacity on an outage to the extent the resource does not provide RA Substitute Capacity for the outage as required under Section 40.9.3.6.

(d) **Exclusions from RAAIM for certain Outage types.** The RAAIM Availability Assessment excludes the capacity, duration, and must-offer requirement for local and/or system Resource Adequacy Capacity or Flexible RA Capacity on an Outage in a nature of work category specified in the Business Practice Manual that relates to: (i) an administrative action by the resource owner; (ii) a cause outside of the control of the resource owner, (iii) or a short-term use limitation; or (iv) a non-Run-of-River Resource hydroelectric Generating Unit’s management of water-related operational or regulatory limitations. Through the December 31, 2020, Trading Day, item (iv) of this Section 40.9.3.4(d) applies only to a hydroelectric Generating Unit that has limited the capacity it has shown on the monthly Supply Plan corresponding to the day of the Outage to reflect historical hydrological conditions or actual hydrological conditions in 2020. The limitations based on hydrological conditions must be mutually agreed upon with the unit’s Scheduling Coordinator and the CAISO. Starting with the January 1, 2021, Trading Day, item (iv) of this Section 40.9.3.4(d) applies only to a hydroelectric Generating Unit whose Qualifying Capacity was established pursuant to a CPUC or Local Regulatory Authority methodology under which the Qualifying Capacity is calculated to reflect historical hydrological conditions.

(e) **Derates on Generating Units Providing system RA Capacity and Listed Local RA Capacity.** If a Generating Unit providing both system RA Capacity and Listed Local RA Capacity is on Forced Outage, then for purposes of RAAIM and RA Substitute Capacity the quantity of the Forced Outage will be apportioned first to the system RA Capacity provided from that Generating Unit. If the quantity of the Forced Outage exceeds the quantity of system RA Capacity provided by the Generating Unit, then the remainder of the Forced Outage shall be apportioned to the Listed Local RA Capacity provided by the Generating Unit.

**40.9.3.5 [Not Used]**

**40.9.3.6 Substitute Capacity**

**40.9.3.6.1 [Not Used]**

**40.9.3.6.2 CAISO Evaluation of Need for Substitute Capacity for Forced Outages**

A Forced Outage on a RA Resource, irrespective of whether the resource is providing RA Capacity or Flexible RA Capacity, subjects the resource’s Scheduling Coordinator to RAAIM unless the Scheduling Coordinator for the resource provides RA Substitute Capacity by the deadline specified in the relevant Business Practice Manual, the outage is exempt from RAAIM as set forth in Section 9 or Section 40, the outage is cancelled, or the outage is rescheduled.

**40.9.3.6.3 General Provisions on Substitute Capacity**

(a) **Substitution**

If the Resource Adequacy Resource on Outage and the substituting resource do not have the same Scheduling Coordinator, the Scheduling Coordinator for the substituting resource must confirm and approve the proposed substitution in accordance with the process set forth in the Business Practice Manual.

(b) **Availability**

(1) RA Substitute Capacity must be operationally available to the CAISO:

(2) Capacity on, or scheduled to be on, a Forced Outage, Approved Maintenance Outage, or de-rate, is not operationally available and shall not qualify to be RA Substitute Capacity for the duration of the period that it is unavailable.

(3) RMR Capacity, including Legacy RMR Capacity, CPM Capacity, and capacity committed to be Resource Adequacy Capacity in a monthly Supply Plan shall not qualify to be RA Substitute Capacity for the duration of that commitment.

(4) RA Substitute Capacity shall not qualify to be RMR Capacity, including Legacy RMR Capacity, CPM Capacity, or Resource Adequacy Capacity in a monthly Supply Plan, for the duration of the substitution.

(5) If a resource provides RA Substitute Capacity for multiple Resource Adequacy Resources under Section 40.9.3.6.6, the same capacity committed as RA Substitute Capacity for one Resource Adequacy Resource shall not qualify as RA Substitute Capacity for a different Resource Adequacy Resource during the same substitution period.

(6) RA Substitute Capacity will be treated as Resource Adequacy Capacity during the period of substitution for purposes of a Forced Outage or de-rate allocation.

(c) **Timing of Substitution Request**

(1) **Day-Ahead Market.** Requests for substitution for Forced Outages in the Day-Ahead Market must be submitted in accordance with the timeline specified in the Business Practice Manual and be approved by the CAISO to be included in the Day-Ahead Market for the next Trading Day. Requests for substitution for Forced Outages in the Day-Ahead Market submitted at or after the timeline specified in the Business Practice Manual and that are approved by the CAISO will be included in the Day-Ahead Market for the second Trading Day.

(2) **Real-Time Market.** Requests for substitution for Forced Outages in the Real-Time Market must be submitted in accordance with the timeline in the Business Practice Manual.

**40.9.3.6.4 RA Substitute Capacity from a Single Source**

(a) **Option.** The Scheduling Coordinator for a Resource Adequacy Resource that is on Outage may provide RA Substitute Capacity for that capacity from a single resource.

(b) **Local Capacity Area Resource Substitution**

(1) **Pre-Qualified Substitution.**

(A) **Annual Process.** The CAISO annually will conduct a process to assess the eligibility of resources to pre-qualify as RA Substitute Capacity for Local Capacity Resource Adequacy Resources that potentially could be Listed Local RA Capacity in the time period covered by the process. The CAISO will publish a list of the pre-qualified resources in accordance with the timeline in the Business Practice Manual.

(B) **Pre-Qualification Requirement.** The CAISO will pre-qualify a resource to provide RA Substitute Capacity that is located at the same bus as, or a compatible bus to, that of the Local Capacity Area Resource Adequacy Resource for which it could substitute.

(C) **Request.** To use a pre-qualified resource in the Day-Ahead Market or Real-Time Market as RA Substitute Capacity, the Scheduling Coordinator for the Local Capacity Area Resource Adequacy Resource on Outage must submit a timely substitution request in accordance with Section 40.9.3.6.3(c).

(D) **Approval.** The CAISO will grant a request that meets the requirements in Sections 40.9.3.6.4(b)(1)(C) and 40.9.3.6.3(b).

(2) **Non-Pre-Qualified Substitution.**

(A) **Day-Ahead Market.**  The Scheduling Coordinator for Listed Local RA Capacity on Outage may submit a request to substitute a non-pre-qualified resource only in the Day-Ahead Market.

(B) **Request.** To use a non-pre-qualified resource as RA Substitute Capacity, the Scheduling Coordinator for the Listed Local RA Capacity must submit a timely substitution request in accordance with Section 40.9.3.6.3(c), and the alternate resource must be located in the same Local Capacity Area.

(C) **Approval.** The CAISO will grant a request that meets the requirements in Sections 40.9.3.6.4(b)(2)(A) and (B), and 40.9.3.6.3(b).

(c) **Non-Local Capacity Area Resource Substitution**

(1) **Request.** To use a resource as RA Substitute Capacity, the Scheduling Coordinator for RA Capacity other than Listed Local RA Capacity that has an Outage must submit a timely substitution request in the Day-Ahead Market or Real-Time Market in accordance with Section 40.9.3.6.3(c).

(2) **Approval.** The CAISO will grant the request if the alternate resource has adequate deliverable capacity to provide the RA Substitute Capacity and meets the requirements in Sections 40.9.3.6.4(c)(1) and 40.9.3.6.3(b). (d) **External Resources**

(1) **Request.** To use a Dynamic System Resource, Non-Dynamic System Resource, NRS-RA Resource, or Pseudo-Tie as RA Substitute Capacity, the Scheduling Coordinator for a Resource Adequacy Resource that has an Outage or de-rate must submit a timely substitution request in the Day-Ahead Market in accordance with Section 40.9.3.6(c).

(2) **Approval.** The CAISO will grant the request if the alternate resource is external to the CAISO Balancing Authority Area (including Pseudo-Ties), the Scheduling Coordinator for the resource has an adequate available import allocation at the resource’s Scheduling Point to provide the RA Substitute Capacity, and meets the requirements in Sections 40.9.3.6.1(d)(1) and 40.9.3.6(b).

(e) **Flexible RA Capacity**

(1) **Request.** To use a resource as RA Substitute Capacity, the Scheduling Coordinator for the Flexible RA Resource that has a Forced Outage must submit a timely substitution request in the Day-Ahead Market or Real-Time Market in accordance with Section 40.9.3.6.3(c) and specify the MW of RA Substitute Capacity to be provided, which may not exceed the MWs of the outage.

(2) **Approval.** The CAISO will grant the request if the alternate resource has adequate deliverable capacity to provide the RA Substitute Capacity, meets the applicable requirements in Sections 40.9.3.6.4(e) and 40.9.3.6.3(b), and is capable of meeting the must-offer obligation in Section 40.10.6 applicable to the highest quality Flexible Capacity Category for the MWs of the Flexible RA Capacity commitments of the resource on outage and the alternate resource.

**40.9.3.6.5 RA Substitute Capacity from Multiple Resources**

(a) **Option.** The Scheduling Coordinator for a Resource Adequacy Resource on Outage may submit a request to substitute that capacity with RA Substitute Capacity from multiple alternate resources, including a resource already providing RA Substitute Capacity for one or more Resource Adequacy Resources.

(b) **Local Capacity Area Resource Substitution**

(1) **Request.** To use RA Substitute Capacity from multiple resources, the Scheduling Coordinator for Listed Local RA Capacity on Outage must submit a timely substitution request in the Day-Ahead Market in accordance with Section 40.9.3.6.3(c) if any of the alternate resources are not pre-qualified to substitute for the resource on the outage; however, if all of the alternate resources are pre-qualified to provide RA Substitute Capacity for that resource, the request may be submitted in the Day-Ahead Market or Real-Time Market.

(2) **Approval.** The CAISO will grant the request if it meets the requirements in Sections 40.9.3.6.5(b)(1) and 40.9.3.6.3(c) and the alternate resources are either pre-qualified, or are not pre-qualified but are located in the same Local Capacity Area as the Resource Adequacy Resource.

(c) **Non-Local Capacity Area Resources**

(1) **Request.** To use RA Substitute Capacity from multiple resources, the Scheduling Coordinator for RA Capacity other than Listed Local RA Capacity on Outage must submit a timely substitution request in the Day-Ahead Market or the Real-Time Market in accordance with Section 40.9.3.6.3(c).

(2) **Approval.** The CAISO will grant the request if all of the alternate resources meet the requirements in Sections 40.9.3.6.5(c)(1) and 40.9.3.6.3(c).

(d) **External Resources**

(1) **Request.** To use multiple Dynamic System Resources, Non-Dynamic System Resources, NRS-RA Resources, or Pseudo-Ties as RA Substitute Capacity, the Scheduling Coordinator for a Resource Adequacy Resource that has an Outage must submit a timely substitution request in the Day-Ahead Market in accordance with Section 40.9.3.6.3(c).

(2) **Approval.** The CAISO will grant the request if the alternate resources are external to the CAISO Balancing Authority Area (including Pseudo-Ties), and the Scheduling Coordinator of each alternate resource has an adequate available import allocation at the resource’s Scheduling Point to provide the RA Substitute Capacity, and meet the requirements in Sections 40.9.3.6.5(d)(1) and 40.9.3.6.3(b).

(e) **Flexible RA Capacity**

(1) **Request.** To use RA Substitute Capacity from multiple resources, the Scheduling Coordinator for a resource providing Flexible RA Capacity on a Forced Outage must submit a timely substitution request in the Day-Ahead Market or the Real-Time Market and the alternate resources must be located in the CAISO Balancing Authority Area, which does not include a Pseudo-Tie of a Generating Unit or a Resource-Specific System Resource.

(2) **Approval.** The CAISO will grant the request if the alternate resources meet the requirements in Sections 40.9.3.6.5(e)(1) and 40.9.3.6.3(c).

**40.9.3.6.6 Multiple Substitution by One Resource.** The Scheduling Coordinator for a resource already providing RA Substitute Capacity may provide RA Substitute Capacity for one or more additional Resource Adequacy Resources on Outage, subject to approval by the CAISO pursuant to Section 40.9.3.6.4 or 40.9.3.6.5.

**40.9.3.6.7 Resource Adequacy Obligation**

To the extent a resource provides RA Substitute Capacity, the resource must meet and comply with all requirements in Section 40 applicable to RA Substitute Capacity for the duration of the substitution; except that RA Substitute Capacity shall be released from this obligation and the substitution requirements in Section 40.9 –

1. at the end of the approved substitution period; or
2. upon request by either the Scheduling Coordinator for the resource on Outage or the Scheduling Coordinator for the substitute resource, and approval by the other Scheduling Coordinator, in accordance with the process set forth in the Business Practice Manual.

**40.9.3.6.8 Treatment of Unbid Capacity**

If the Scheduling Coordinator for RA Substitute Capacity does not submit Bids or Self-Schedules for all or a portion of that capacity in accordance with Section 40.6 or 40.10.6, the CAISO –

(1) will treat the unbid capacity as unavailable for purposes of Section 40.9; and

(2) will reflect that unavailability in the RAAIM availability calculation for the Resource Adequacy Resource providing the RA Substitute Capacity.

**40.9.3.6.9 Substitution Opportunity Information**

In order to make information available to Market Participants pertinent to the provisions of this Section 40.9.3.6, the CAISO will:

(a) Annually post on the CAISO Website the due dates for each month of the following Resource Adequacy compliance year the various submissions the CAISO requires under the Resource Adequacy program; and

(b) Provide the opportunity for Market Participants to post and view information on an electronic bulletin board about non-Resource Adequacy Capacity that may be needed or available as RA Substitute Capacity in the bilateral market. Use of the bulletin board is voluntary and is for informational purposes only.

### 40.9.4 Additional Rules on Calculating Monthly and Daily Average Availability

(a) The CAISO shall determine a resource’s monthly average availability on a percentage basis, based on:

(1) the availability assessment of the resource’s minimum daily availability of local and/or system Resource Adequacy Capacity under Section 40.9.3.1, Flexible RA Capacity under Section 40.9.3.2, and overlapping Resource Adequacy commitments under Section 40.9.3.3, in the Day-Ahead Market and Real-Time Market;

(2) separately-calculated availability assessments for local and/or system Resource Adequacy Capacity in one category and Flexible RA Capacity in a second category, with availability in an hour with overlapping commitments under Section 40.9.3.3 accounted for in the Flexible RA Capacity category availability assessment;

(3) The relative daily proportion of capacity as provided as local and/or system Resource Adequacy Capacity and Flexible RA Capacity, including both overlapping and non-overlapping commitments based on the Availability Assessment of Hours;

(4) the capacity, duration, and must-offer requirement for local and/or system Resource Adequacy Capacity or Flexible RA Capacity on an Outage, except to the extent the resource provides RA Substitute Capacity for the outage in accordance with Section 40.9.3.6, the Outage is approved by the CAISO without requiring RA Substitute Capacity under other authority of Section 9 or Section 40, or the Outage is excluded from RAAIM under Section 40.9.3.4(d); and

(5) the capacity, duration, and must-offer requirement for any RA Substitute Capacity or CPM Capacity the resource is committed to provide.

(b) If the resource’s minimum daily availability is the same in the Day-Ahead Market and the Real-Time Market, the CAISO will use the availability in the Real-Time Market in the calculation of the monthly average availability.

(c) If the resource is committed to provide local and/or system RA capacity and Flexible RA Capacity in a month, but is not committed to provide both for the full month, the CAISO prorates the number of days that local and/or system Resource Adequacy Capacity and Flexible RA Capacity was provided against the total number of days in the month.

### 40.9.5 Availability Standard

(a) **Percentage.** The Availability Standard shall be 96.5 percent each month.

(b) **Availability Range.** The CAISO shall apply the Availability Standard with a bandwidth of plus and minus two percent, which produces a range with a lower bound of 94.5 percent and an upper bound of 98.5 percent.

### 40.9.6 Non-Availability Charges and Availability Incentive Payments

(a) **Non-Availability Charges.** A resource providing local and/or system Resource Adequacy Capacity, Flexible RA Capacity, or CPM Capacity that is subject to the availability assessment in accordance with Section 40.9.3 and whose monthly availability calculation under Section 40.9.4 is below the lower bound of the monthly Availability Standard of 94.5 percent will be subject to a Non-Availability Charge for the month.

(b) **Availability Incentive Payments.** A resource providing local and/or system Resource Adequacy Capacity, Flexible RA Capacity, or CPM Capacity that is subject to the availability assessment under Section 40.9.3 and whose availability calculation under Section 40.9.4 is above the upper bound of the monthly Availability Standard of 98.5 percent will be eligible for an Availability Incentive Payment for the month.

(c) **No Payment or Charge.** A resource providing local and/or system Resource Adequacy Capacity, Flexible RA Capacity, or CPM Capacity that is subject to the availability assessment under Section 40.9.3 and whose monthly availability calculation under Section 40.9.4 is equal to or between the lower bound of 94.5 percent and the upper bound of 98.5 percent of the Availability Standard will not be assessed a Non-Availability Charge nor paid an Availability Incentive Payment.

(d) **Advisory Period.** During an advisory period of April 1, 2018 through May 31, 2018, the CAISO will show the Non-Availability Charges and Availability Incentive Payments on Settlement Statements but will not include those Non-Availability Charges and Availability Incentive Payments on Invoices for financial settlement.

(e) **Separate Calculation of Payments and Charges for Flexible RA Capacity.** The CAISO will calculate separate Non-Availability Charges and Availability Incentive Payments for Resource Adequacy Resources providing Flexible RA Capacity. For RMR Resources, the Non-Availability Charge will be based on the RMR Contract capacity costs. RMR Capacity is otherwise treated the same way as Resource Adequacy Capacity.

**40.9.6.1 Determination of Non-Availability Charge**

(a) **Calculation**

(1) **RA Capacity.** The Non-Availability Charge for a Resource Adequacy Resource providing local, system, or Flexible RA Capacity shall be determined by the resource’s average monthly RA and Flexible RA MWs multiplied by the difference between the lower bound of the monthly Availability Standard of 94.5 percent and the resource’s monthly availability percentage, and multiplying the product by the RAAIM price.

(2) **CPM Capacity.** The Non-Availability Charge for a Resource Adequacy Resource providing CPM Capacity shall be determined by the resource’s average monthly CPM MWs multiplied by the difference between the lower bound of the monthly Availability Standard of 94.5 percent and the resource’s monthly availability percentage, and multiplying the product by the maximum of the resource’s CPM price and the RAAIM price.

(b) **RAAIM** **Price.** TheRAAIM price shall be 60 percent of the CPM Soft-Cap Price in Section 43A.4.1.1.

(c) **Separate Collection of Non-Availability Charges for Flexible RA Capacity.** Separately-calculated Non-Availability Charges collected for Resource Adequacy Resources providing Flexible RA Capacity will be held separate from other Non-Availability Charges assessed for Resource Adequacy Resources.

**40.9.6.2 Determination of Availability Incentive Payment**

(a) **Self-Funding.** The Availability Incentive Payment will be funded entirely through the monthly Non-Availability Charges assessed. Availability Incentive Payments for Resource Adequacy Resources providing Flexible RA Capacity will be funded exclusively by Non-Availability Charges assessed against Resource Adequacy Resources providing Flexible RA Capacity.

(b) **Eligible Capacity.** The capacity of a Resource Adequacy Resource providing local, system or Flexible RA Capacity that is eligible to receive an Availability Incentive Payment shall be the resource’s average monthly MWs of capacity that exceed the upper bound of the Availability Standard.

(c) **Calculation.**

(1) The monthly Availability Incentive Payment rate will equal the total Non-Availability Charges assessed for the month plus any unpaid funds under Section 40.9.6.2(d), divided by the total Resource Adequacy Capacity eligible to receive the Availability Incentive Payment that month.

(2) The Availability Incentive Payment rate shall not exceed three times the Non-Availability Charge rate.

(3) The Availability Incentive Payment the CAISO shall pay to each eligible resource shall equal the product of its eligible capacity and the Availability Incentive Payment rate.

(d) **Unpaid Funds.**  Any Non-Availability Charge funds that are not distributed to Resource Adequacy Resources eligible to receive Availability Incentive Payments in a month will be added to the funds available for Availability Incentive Payments in the next month and will continue to roll over to successive months until the end of the year. The CAISO distributes any unallocated funds remaining after the CAISO settles December monthly RAAIM Non-Availability Charges and Non-Availability Incentive Payments. The separate pool of undistributed Non-Availability Charge funds collected for local and/or system Resource Adequacy Capacity will be distributed to Load Serving Entities based on their load ratio share for the year. The separate pool of undistributed Non-Availability Charge funds collected for Flexible RA Capacity will be distributed to Load Serving Entities based on their overall ratio of obligation to demonstrate Flexible RA Capacity for the year. 40.9.7 Reporting

By July 1 of each year, the CAISO will provide an informational report that will be posted on the CAISO Website and include information on the average actual availability each month of Resource Adequacy Resources, the total amount of Non-Availability Charges assessed and the total amount of Availability Incentive Payments made.

## 40.10 Flexible RA Capacity

### 40.10.1 Flexible Capacity Needs Assessment

The CAISO shall annually conduct a study to determine the Flexible Capacity Need of the CAISO Balancing Authority Area for each month of the next calendar year and provide the results of the study in the Flexible Capacity Needs Assessment.

**40.10.1.1 Process**

(a) **Schedule.** The CAISO shall conduct the study pursuant to the schedule set forth in the Business Practice Manual, which shall include a process for stakeholders to review and provide input on the study methodology and assumptions and on the draft study results.

(b) **Completion and Distribution.** The CAISO shall provide the final results of the Flexible Capacity Needs Assessment to each Local Regulatory Authority in the CAISO Balancing Authority Area and post the Flexible Capacity Needs Assessment on the CAISO Website no later than 120 days prior to the date that the annual Flexible RA Capacity Plans must be submitted under Section 40.

**40.10.1.2 Required Information from LSEs**

(a) **Submission Requirement.** The Scheduling Coordinator for each Load Serving Entity in the CAISO Balancing Authority Area shall submit the information required by this Section, no later than January 15 each year, for use in the CAISO’s study to generate minute-by-minute net-load data that will be used to determine the Maximum Three-Hour Net-Load Ramp for each month.

(b) **Required Information.** The Scheduling Coordinator for each Load Serving Entity in the CAISO Balancing Authority Area must submit information that –

(1) covers the calendar year in which the information is submitted and each year in the next five-year period;

(2) identifies each wind and solar resource connected to the CAISO Controlled Grid, and distributed wind and solar resources, that is owned, in whole or in part, by the Load Serving Entity, or under contractual commitment to the Load Serving Entity or the Load-following MSS Load Serving Entity, for all or a portion of its capacity;

(3) indicates the status of the resource as either in service or in development with its expected commercial operation date;

(4) for each wind and solar resource, specifies the MWs of installed capacity, renewable energy area location, MWs of flexible capacity owned by or contractually committed to the Load Serving Entity, and other information required by the Business Practice Manual;

(5) describes the balancing services, if any, provided by another balancing authority area for a wind or solar resource that is located outside of the CAISO Balancing Authority Area and that is owned by or contractually committed to the Load Serving Entity; and

(6) forecasts the MW of installed, behind-the-meter solar capacity in the Load Serving Entity’s service area or part of its forecast served load.

(c) **Confidential Treatment.** The CAISO will treat the resource-specific information provided under Section 40.10.1.2(b) as confidential under Section 20.

(d) **Aggregated Information.** In addition to the required resource-specific information, the Scheduling Coordinator for each Load Serving Entity in the CAISO Balancing Authority Area shall submit the information required in Section 40.10.1.2(b) on an aggregated basis, as described in the Business Practice Manual, for inclusion in the Flexible Capacity Needs Assessment that will be posted on the CAISO Website.

**40.10.1.2.1 Incomplete or Inaccurate Information.**

(a) **Rerun of Study.** If the CAISO finds that a Load Serving Entity submitted incomplete or inaccurate information under Section 40.10.1.2(b), which was used in the calculation of the Flexible Capacity Need for the next calendar year, the CAISO may rerun its study using corrected information to recalculate Flexible Capacity Need for the entire year.

(b) **Criteria for Rerun.** The CAISO will not rerun its study to recalculate the Flexible Capacity Need unless:

(1) the incomplete or inaccurate information represents a net error in excess of either (i) 200 MW; or (ii) one percent of the total MWs of wind and solar capacity submitted under Section 40.10.1.2(b) for any month; and

(2) the CAISO has sufficient time to obtain corrected information and complete rerunning the study for the next calendar year by May 1.

(c) **Revised Flexible Capacity Need.** If the CAISO determines that the requirements in Sections 40.10.1.2.1(a) and (b) are met, the CAISO will recalculate the Flexible Capacity Need for the next calendar year and will no later than May 1 post a revised Flexible Capacity Needs Assessment on the CAISO Website.

**40.10.1.3 Flexible Capacity Need Methodology**

The CAISO shall conduct the study to determine the Flexible Capacity Need for the system for each month of the next calendar year as follows:

(1) forecast the minute-to-minute system load and net-load using actual load data, as adjusted for monthly peak load growth, and generation profiles for wind and solar resources that are in-service or expected to be in-service during the study period;

(2) calculate the Maximum Three-Hour Net-Load Ramp for each month using the forecasted minute-to-minute system net-load;

(3) determine the higher of the most severe single contingency or 3.5 percent of forecasted peak load for each month;

(4) may include a forecast adjustment, as described in Section 40.10.1.4; and

(5) compute the resultant Flexible Capacity Need for each month based on the sum of the Maximum Three-Hour Net-Load Ramp, and the higher of the most severe single contingency or 3.5 percent of the forecasted monthly peak load.

**40.10.1.4 Flexible Capacity Need Forecast Adjustment**

(a) The Flexible Capacity Need determination may include a positive or negative forecast adjustment to capture a systemic difference between the value determined in Section 40.10.1.3(3) and the historic amount of Operating Reserves met by Flexible Capacity;

(b) The CAISO will determine the need for a forecast adjustment in consultation with the CPUC and other Local Regulatory Authorities, and as part of the stakeholder process under Section 40.10.1.1; and

(c) The amount of the forecast adjustment calculated for each month shall not exceed the forecasted monthly peak Operating Reserves multiplied by the difference between (i) the historic percentage of Operating Reserves met by Flexible RA Capacity and (ii) the percentage calculation that results from dividing the quantity determined in Section 40.10.1.3(3) by the forecasted monthly peak Operating Reserves.

**40.10.1.5 Flexible Capacity Category Need**

(a) The CAISO shall calculate the total system amount of Flexible Capacity needed in each Flexible Capacity Category, for each month of the next calendar year to ensure that forecast system operational needs will be met, as follows:

(1) The minimum quantity of Flexible Capacity needed in the Flexible Capacity Category for base ramping resources for each month will be calculated on a seasonal basis based on the system ramping characteristics identified in the Flexible Capacity Needs Assessment and the changes in MWs of the Maximum Secondary Three-Hour Net-Load Ramps for each month within a season, and will be specified in MW and as the percentage of total Flexible Capacity Needs.

(2) The maximum quantity of Flexible Capacity in the Flexible Capacity Category for peak ramping resources will be calculated for each month as the difference between the minimum quantity needed in the Flexible Capacity Category for base ramping resources and the total Flexible Capacity Need, and will be specified in MW and as the percentage of total Flexible Capacity Needs.

(3) The maximum quantity of Flexible Capacity in the Flexible Capacity Category for super-peak ramping resources will be five percent of the total Flexible Capacity Need.

(b) The CAISO shall provide the results of the Flexible Capacity Category need determination with the Flexible Capacity Needs Assessment.

### 40.10.2 Allocation of Flexible Capacity Needs

The CAISO will calculate each Local Regulatory Authority’s allocable share of the total system Flexible Capacity Need, and the contribution of each of the Local Regulatory Authority’s jurisdictional Load Serving Entities to the Maximum Three-Hour Net-Load Ramp used to calculate its share of the total system Flexible Capacity Need. The CAISO shall provide these calculations to each Local Regulatory Authority no later than 120 days prior to the date that the annual Flexible RA Capacity Plans must be submitted under Section 40. Nothing in this Section 40 obligates any individual Load Serving Entity to demonstrate that it has procured Flexible Capacity Resources to satisfy a minimum or maximum quantity needed, as applicable, within each Flexible Capacity Category.

**40.10.2.1 Calculation of LRA Allocations**

(a) **Allocation of Maximum Three-Hour Net-Load Ramp.** The CAISO will calculate the Local Regulatory Authority’s allocable share of the Flexible Capacity Need as the average of the sum of its jurisdictional Load Serving Entities’ change in load, minus the change in wind output, minus the change in solar PV output, minus the change in solar thermal output during the five highest three-hour net-load changes in the month.

(b) **Allocation of MSSC or Forecasted Peak Load.** The CAISO will determine the higher of the most severe single contingency or 3.5 percent of forecasted peak load for each Load Serving Entity based on the respective Load Serving Entity’s peak load ratio share, and calculate each Local Regulatory Authority’s allocable share based on the sum of its jurisdictional Load Serving Entities’ shares.

(c) **Allocation of Forecast Adjustment.** If the CAISO includes a forecast adjustment in its draft study results, it will allocate the forecast adjustment using the same methodology set forth in Section 40.10.2.1(b).

**40.10.2.2 Allocation to Load-Following MSS**

(a) The CAISO will calculate the allocable share of the Flexible Capacity Need for each Load-following MSS as –

(1) the Local Regulatory Authority’s average percent contribution to the change in wind output, minus the change in solar PV output, minus the change in solar thermal output, during the five highest three-hour net-load changes in the month, for resources not included in the Load-following MSS Load Serving Entity’s resource portfolio; and

(2) plus the lesser of the MSS contribution calculated under Section 40.10.2.2(a)(1) or 3.5 percent of its forecasted peak load.

(3) plus the Load-following MSS Load Serving Entity’s allocable share of any forecast adjustment under Section 40.10.1.4.

(b) The CAISO will deduct the Flexible Capacity Need allocated to each Load-following MSS from the calculation to determine whether a cumulative deficiency in Flexible RA Capacity exists under Section 43A.2.7.

(c) If the Load-following MSS Load Serving Entity’s contribution to the three-hour net-load ramp calculated under Section 40.10.2.2(a)(1) is less than its contribution to the 3.5 percent of expected peak load, the CAISO will not reallocate that difference to other Local Regulatory Authorities to determine whether a cumulative deficiency in Flexible RA Capacity exists under Section 43A.2.7.

### 40.10.3 Flexible Capacity Categories

**40.10.3.1 Flexible Capacity Category Calculation**

A resource qualifies to provide Flexible RA Capacity in each Flexible Capacity Category for which it meets the qualifications set forth in this Section 40.10.3.

**40.10.3.2 Flexible Capacity Category – Base Ramping Resources**

(a) **Resource Criteria.** Base ramping resources must meet all of the following criteria, except as provided in Sections 40.10.3.2(b) and (c) –

(1) The resource must be capable of providing Flexible RA Capacity to the CAISO Markets through Economic Bids for Energy and Economic Bids for Ancillary Services that are not flagged as Contingency Only in the Day-Ahead Market, if and to the extent the resource is certified to provide Ancillary Services, submitted daily for the 17-hour period from 5:00 a.m. through 10:00 p.m.;

(2) The resource must be capable of providing Energy for a minimum of six hours up to its full Effective Flexible Capacity value including PMin;

(3) The resource must be capable of being available seven days a week;

(4) The resource must be able to provide the minimum of (i) two Start-Ups per day for every day of the month or sixty Start-Ups per month, or (ii) the number of Start-Ups allowed by its operational limits, including minimum up and minimum down time; and

(5) The resource must not have annual or monthly limitations on the number of Start-Ups or the amount of energy produced that, on a daily basis, are lower than the requirements in Section 40.10.3.2(a)(1) through (4).

(b) **Use-Limited Resource**

(1) A Use-Limited Resource may be included in this category if it meets the criteria in Section 40.10.3.2(a), except that use-limited resources providing Flexible RA Capacity are not required to submit bids for Ancillary Services in the Day-Ahead Market or the Real-Time Market.

(2) A Load Serving Entity may include in this category a combined resource consisting of two Use-Limited Resources that do not individually meet the minimum operational and availability requirements but in combination meet the criteria in Section 40.10.3.2(a).

(3) The Flexible RA Capacity amount for the combined resource will be less than or equal to the lowest Effective Flexible Capacity value shown on the Resource Flexible RA Capacity Plan for a resource in the combination.

(4) The combined resource shall be subject to the must-offer obligation in Section 40.10.6.1(e)(2) for the Flexible RA Capacity amount shown on the monthly Resource Flexible RA Capacity Plan for the combination.

(c) **Non-Generator Resource.** A Non-Generator Resource that elects to provide Flexible RA Capacity may be included in this category if it meets the criteria in Section 40.10.3.2(a). A Non-Generator Resource that elects to provide Flexible RA Capacity and Regulation Energy Management is not eligible to be included in this category.

**40.10.3.3 Flexible Capacity Category – Peak Ramping Resources**

(a) **Resource Criteria.** Peak ramping resources must meet all of the following criteria, except as provided in Sections 40.10.3.3(b) and (c) --

(1) The resource must be capable of providing Flexible RA Capacity to the CAISO Markets through Economic Bids for Energy and Economic Bids for Ancillary Services that are not flagged as Contingency Only in the Day-Ahead Market, if and to the extent the resource is certified to provide Ancillary Services, which must be submitted daily for a five-hour period to be determined by the CAISO on a seasonal basis;

(2) The resource must be capable of providing Energy for a minimum of three continuous hours up to its full Effective Flexible Capacity value including PMin;

(3) The resource must be capable of being available seven days a week.

(4) The resource must be capable of at least one Start-Up per day; and

(5) The resource must not have annual or monthly limitations on the number of unit Start-Ups or the amount of energy produced that, on a daily basis, are lower than the requirements in Section 40.10.3.3(a)(1) through (4).

(b) **Use-Limited Resource.**

(1) A Use-Limited Resource may be included in this category if it meets the criteria in Section 40.10.3.3(a), except that use-limited resources providing Flexible RA Capacity are not required to submit bids for Ancillary Services in the Day-Ahead Market or the Real-Time Market.

(2) A Load Serving Entity may include in this category a combined resource consisting of two Use-Limited Resources that do not individually meet the minimum operational and availability requirements but in combination meet the criteria in Section 40.10.3.3(a).

(3) The Flexible RA Capacity amount for the combined resource will be less than or equal to the lowest Effective Flexible Capacity value shown on the Resource Flexible RA Capacity Plan for a resource in the combination.

(4) The combined resource shall be subject to the must-offer obligation in Section 40.10.6.1(e)(2) for the Flexible RA Capacity amount shown on the monthly Resource Flexible RA Capacity Plan for the combination.

(c) **Non-Generator Resource.** A Non-Generator Resource that elects to provide Flexible RA Capacity may be included in this category if it meets the criteria in Section 40.10.3.3(a). A Non-Generator Resource that elects to provide Flexible RA Capacity and Regulation Energy Management is not eligible to be included in this category.

(d) **Base Ramping Resource.** A resource that meets the qualifications of the Flexible Capacity Category for base ramping resources also qualifies to be included in this category as a peak ramping resource; however, a resource that meets only the qualifications of a peak ramping resource does not qualify as a base ramping resource.

**40.10.3.4 Flexible Capacity Category – Super-Peak Ramping Resources.**

(a) **Resource Criteria.** Super-peak ramping resources must meet all of the following criteria, except as provided in Sections 40.10.3.4(b), (c) and (d) --

(1) The resource must be capable of providing Flexible RA Capacity to the CAISO Markets through Economic Bids for Energy and Economic Bids for Ancillary Services Bids that are not flagged as Contingency Only in the Day-Ahead Market, if and to the extent the resource is certified to provide Ancillary Services, which must be submitted each weekday that is not holiday, for a five-hour period to be determined by the CAISO on a seasonal basis;

(2) The resource must be capable of providing Energy for a minimum of three continuous hours up to its full Effective Flexible Capacity value including PMin;

(3) The resource must be capable of being available on weekdays that are not holidays, as defined in the Business Practice Manual;

(4) The resource must be capable of at least one Start-Up per day; and

(5) The resource must be capable of responding to at least five CAISO dispatches per month, during the five-hour period of the must offer obligation, for the resource to Start-Up.

(b) **Use-Limited Resource.**

(1) A Use-Limited Resource may be included in this category if it meets the criteria in Section 40.10.3.4(a), except that use-limited resources providing Flexible RA Capacity are not required to submit bids for Ancillary Services in the Day-Ahead Market or the Real-Time Market.

(2) A Load Serving Entity may include in this category a combined resource consisting of two Use-Limited Resources that do not individually meet the minimum operational and availability requirements but in combination meet the criteria in Section 40.10.3.4(a).

(3) The Flexible RA Capacity amount for the combined resource will be less than or equal to the lowest Effective Flexible Capacity value shown on the Resource Flexible RA Capacity Plan for a resource in the combination.

(4) The combined resource shall be subject to the must-offer obligation in Section 40.10.6.1(e)(2) for the Flexible RA Capacity amount shown on the monthly Resource Flexible RA Capacity Plan for the combination.

(c) **Non-Generator Resource.** A Non-Generator Resource may be included in this category if it meets the criteria in Section 40.10.3.4(a) and is not registered in the CAISO’s Master File as a Regulation Energy Management resource.

(d) **Non-Generator Resource, Regulation Energy Management.** A Non-Generator Resource that is a Regulation Energy Management resource may be included in this category if it meets the following criteria –

(1) The resource must be capable of providing Regulation Energy Management to the CAISO Markets through Economic Bids for Regulation Up and Regulation Down submitted daily for a 17-hour period from 5:00 a.m. through 10:00 p.m.;

(2) The resource shall not submit bids to provide Energy;

(3) The resource must be capable of being available seven days a week;

(4) The resource must be capable of unlimited Start-Ups per day; and

(5) The resource must be registered as a Non-Generator Resource providing Regulation Energy Management in the CAISO’s Master File.

(e) **Base Ramping and Peak Ramping Resources.** A resource that meets the qualifications of the Flexible Capacity Category for base ramping resources or peak ramping resources also qualifies to be included in this category as a super-peak ramping resource; however, a resource that meets only the qualifications of a super-peak ramping resource does not qualify as a base ramping resource or a peak ramping resource.

**40.10.3.5 Flexible Capacity Category by Resource**

The CAISO will provide to the Scheduling Coordinator of each resource a non-binding determination of the Flexible Capacity Category with the highest qualifications for which the resource qualifies to provide Flexible Capacity, as provided in Section 40.10.4.

**40.10.3.6 Non-Eligible Resources**

Intertie resources and imports, other than Pseudo-Ties and Dynamic Scheduled resources, and Proxy Demand Resources that have elected, per Section 4.13.3, to bid and be dispatched in the Real-Time Market in Hourly Blocks or fifteen (15) minute intervals, are not eligible to provide Flexible RA Capacity.

### 40.10.4 Effective Flexible Capacity

The CAISO shall calculate the Effective Flexible Capacity value for each resource. The CAISO shall publish the draft and final lists of the Effective Flexible Capacity values for such resources and the Flexible Capacity Categories for which each resource qualifies to provide Flexible Capacity on the CAISO Website each year in accordance with the schedule for publishing the Net Qualifying Capacity values, as set forth in the BPM, for use in the next calendar year.

**40.10.4.1 Effective Flexible Capacity Calculation**

(a) **Flexible Resources.** The CAISO will calculate the Effective Flexible Capacity value of a resource, for use (i) if a Local Regulatory Authority has not established criteria for calculating the Effective Flexible Capacity value for eligible resource types, and (ii) for determining if a cumulative deficiency exists under Sections 43A.2.7(a) and (b), as follows, except as provided in Sections 40.10.4.1 (b) through (f) –

(1) If the Start-Up Time of the resource is greater than 90 minutes, the Effective Flexible Capacity value shall be the weighted average ramp rate of the resource calculated from PMin to Net Qualifying Capacity multiplied by 180 minutes. The Effective Flexible Capacity shall not exceed the difference between the PMin and PMax of the resource.

(2) If the Start-Up Time of the resource is less than or equal to 90 minutes, the Effective Flexible Capacity value shall be the resource’s PMin plus the weighted average ramp rate of the resource calculated from PMin to Net Qualifying Capacity multiplied by the difference between 180 minutes and the resource’s Start-Up Time. The Effective Flexible Capacity shall not exceed the Net Qualifying Capacity of the resource.

(b) **Hydroelectric Generating Unit.** The Effective Flexible Capacity of a hydroelectric generating unit will be the amount of capacity from which the resource can produce Energy consistently for 6 hours assuming that the resource’s physical storage is at maximum capacity at the beginning of that six-hour period. The Effective Flexible Capacity of a hydroelectric generation unit cannot, however, exceed its Net Qualifying Capacity.

(c) **[Not Used]**

(d) **Energy Storage Resource.** The Effective Flexible Capacity value for an energy storage resource will be determined as follows –

(1) for an energy storage resource that provides Flexible RA Capacity but not Regulation Energy Management, the Effective Flexible Capacity value will be the MW output range the resource can provide over three hours of charge/discharge while constantly ramping.

(2) for an energy storage resource that provides Flexible RA Capacity and Regulation Energy Management, the Effective Flexible Capacity value will be the resource’s 15-minute energy output capability.

(e) **Multi-Stage Generating Resource.** The Effective Flexible Capacity value for a Multi-Stage Generating Resource will be calculated using the longest Start-Up Time of the resource’s configuration that has the lowest PMin.

(f) **Combined Heat and Power Resource.** The Effective Flexible Capacity value of a Combined Heat and Power Resource will be the lesser of (i) the resource’s Net Qualifying Capacity, or (ii) the MW difference between the CHP resource’s maximum output and its RMTMax, if the resource has a RMTMax, or its minimum operating level, such quantity not to exceed the quantity of generating capacity capable of being delivered over a three-hour period.

(g) **Hybrid Resource.** The Effective Flexible Capacity value of a Hybrid Resource is the sum of what the Effective Flexible Capacity values of the constituent components of the Hybrid Resource would be if those components were each a distinct Generating Unit.

**40.10.4.2 EFC Omission or Correction**

(a) **Draft List.** The posted draft list of Effective Flexible Capacity values may be modified only as follows –

(1) If the Scheduling Coordinator for a resource that was not included on the draft list of Effective Flexible Capacity values seeks to have the resource included on the list, it must no later than the deadline set forth in the Business Practice Manual submit a request to the CAISO either showing that the resource meets the criteria in Section in 40.10.4.1 or is capable of meeting the criteria, and provide documentation to enable the CAISO to determine the resource’s Effective Flexible Capacity pursuant to the criteria in Section 40.10.4.1.

(2) If the Scheduling Coordinator for a resource that was included on the draft list of Effective Flexible Capacity values seeks to change the value for that resource, it must submit documentation by the deadline set forth in the Business Practice Manual that supports such a change.

(3) The CAISO will review the information submitted and notify the Scheduling Coordinator whether the change was accepted at least 15 days prior to posting the final list of Effective Flexible Capacity values on the CAISO Website.

(b) **Final List.** The CAISO will post on the CAISO Website the final list of Effective Flexible Capacity values for resources that are in service and the Flexible Capacity Categories for which each resource qualifies to provide Flexible Capacity. The final list shall be used for the next calendar year and shall not be changed during that year, except as follows –

(1) If the Net Qualifying Capacity or PMax of a resource included on the final list increases or decreases during the year, and that value is changed in the Master File, the Scheduling Coordinator for the resource may request that the Effective Flexible Capacity value be recalculated to account for the change; or

(2) If a new resource, achieves commercial operation during the year, the Scheduling Coordinator for the resource may request that the CAISO calculate and add its Effective Flexible Capacity value and the Flexible Capacity Categories for which the resource qualifies to provide Flexible Capacity to the final list as an in-service resource.

(c) **Disputes.** Any disputes as to the CAISO’s determination regarding Effective Flexible Capacity shall be subject to the CAISO ADR Procedure.

### 40.10.5 Flexible RA Capacity Plans

**40.10.5.1 LSE Flexible RA Capacity Plans**

(a) **Submission Requirement.** A Scheduling Coordinator must submit annual and monthly LSE Flexible RA Capacity Plans for each Load Serving Entity it represents.

(b) **Annual Plan.** Each annual LSE Flexible RA Capacity Plan must –

(1) demonstrate that the Load Serving Entity has procured for each month at least 90 percent of the annual Flexible RA Capacity requirement determined by the CAISO; or the amount of Flexible RA Capacity required by the Load Serving Entity’s Local Regulatory Authority, if the Local Regulatory Authority has set such requirement;

(2) identify the resources the Load Serving Entity intends to rely on to provide the Flexible RA Capacity, but need not identify the flexible resource adequacy categories; and

(3) include all information and be submitted no later than the last Business Day in October, in accordance with the reporting requirements and schedule set forth in the Business Practice Manual.

(c) **Monthly Plan.** The monthly LSE Flexible RA Capacity Plan must –

(1) demonstrate that the Load Serving Entity procured 100 percent of the total monthly Flexible RA Capacity requirement determined by the CAISO; or the monthly amount of Flexible RA Capacity required by the Local Regulatory Authority, if the Local Regulatory Authority has set such requirement;

(2) include information for purposes of the validation under Section 40.10.5.3(a) and the evaluation for cumulative deficiency under Section 40.10.5.3(c)that shows the MW of Flexible RA Capacity the Load Serving Entity designates based on the total monthly requirement determined by the CAISO within the minimum or maximum quantity, as applicable, for each Flexible Capacity Category; or only if the Local Regulatory Authority has established its own flexible capacity requirement, shows the MW of Flexible RA Capacity the Load Serving Entity designates based on the total monthly requirement determined by the Local Regulatory Authority within the minimum or maximum quantity for each Flexible Capacity Category required by the Local Regulatory Authority, if applicable;

(3) identify all resources the Load Serving Entity will rely on to provide the Flexible RA Capacity and for each resource specify the Flexible Capacity Category in which the Flexible RA Capacity will be provided; and

(4) include all information and be submitted to the CAISO at least 45 days in advance of the first day of the month covered by the plan, in accordance with the reporting requirements and schedule set forth in the Business Practice Manual.

(d) **Correction to Monthly Plan.** The Scheduling Coordinator for the Load Serving Entity may submit at any time from 45 days through 30 days in advance of the first day of the month covered by the plan, a revision to its monthly LSE Flexible RA Capacity Plan to correct either: (i) a discrepancy between its monthly LSE Flexible RA Capacity Plan and the monthly Supply Plan of a Resource Adequacy Resource providing that Load Serving Entity with Flexible RA Capacity; or (ii) a deficiency in how much Flexible RA Capacity was provided on the monthly LSE Flexible RA Capacity Plan. The CAISO will not accept any revisions to a monthly LSE Flexible RA Capacity Plan from 30 days in advance of the relevant month through the end of the month, unless the Scheduling Coordinator for the Load Serving Entity demonstrates good cause for the change and explains why it was not possible to submit the change earlier.

(e) **Reporting Exemption.** Notwithstanding the above, a Load Serving Entity is not obligated to submit a monthly LSE Flexible RA Capacity Plan for a given month if the Load Serving Entity’s contribution to the three-hour net load ramp is less than 1 MW for that month. Except to the extent allowed under section 43A.8.8(e), such Load Serving Entity is not exempt for any relevant cost allocation from a CPM designation made pursuant to Section 43A associated with a monthly RA capacity obligation of less than 1 MW.

**40.10.5.1.1** **Load-Following MSS**

(1) Each Load-following MSS Load Serving Entity for which the CAISO has calculated an allocable share of the Flexible Capacity Need under Section 40.10.2.2 must submit annual and monthly LSE Flexible RA Capacity Plans pursuant to this Section 40.10.5.1 to identify the Flexible RA Capacity it is using to satisfy such requirement.

(2) The Load-following MSS must increase the Flexible RA Capacity in its monthly plan by the MW amount of Capacity for a Variable Energy Resource that is initially shown as being included in the Load-following MSS Load Serving Entity’s resource portfolio in the information required pursuant to Section 40.10.1.2, but is subsequently not included in the current MSS resource portfolio at the time the monthly LSE Flexible RA Capacity Plan is due for the applicable month.

**40.10.5.2 Resource Flexible RA Capacity Plans**

(a) **Submission Requirement.** A Scheduling Coordinator must submit annual and monthly Resource Flexible RA Capacity Plans for each resource it represents that provides Flexible RA Capacity; except that an annual plan is not required for 2015.

(b) **Annual Plan.** The annual Resource Flexible RA Capacity Plan shall --

(1) verify the resource’s agreement to provide Flexible RA Capacity during the next Resource Adequacy Compliance Year; and

(2) include all information and be submitted no later than the last Business Day in October, in accordance with the reporting requirements and schedule set forth in the Business Practice Manual.

(c) **Monthly Plan.** The monthly Resource Flexible RA Capacity Plan shall –

(1) verify the resource’s agreement to provide Flexible RA Capacity during the month;

(2) include an affirmative representation by the Scheduling Coordinator submitting the plan that the CAISO is entitled to rely on the accuracy of the information provided in the plan to perform those functions set forth in this Section 40; and

(3) include all information and be submitted to the CAISO at least 45 days in advance of the first day of the month covered by the plan, in accordance with the reporting requirements and schedule set forth in the Business Practice Manual.

(d) **Correction to Monthly Plan.** The Scheduling Coordinator for the Resource Adequacy Resource may, at any time from 45 days through 30 days in advance of the relevant month, revise its monthly Flexible RA Capacity Plan to correct a discrepancy between its monthly Flexible RA Capacity Plan and a Resource Adequacy Plan of a Load Serving Entity for which that Resource Adequacy Resource is providing Flexible RA Capacity. The CAISO will not accept any revisions to a monthly Flexible RA Capacity Plan less than 30 days in advance of the relevant month through the end of the month, unless the Scheduling Coordinator for the Resource demonstrates good cause for the change and explains why it was not possible to submit the change earlier.

**40.10.5.3 Review of Flexible RA Capacity Plans**

(a) **Validation for Deficiency in an Individual LSE Plan.**

(1) If the Local Regulatory Authority has not established its own flexible capacity procurement requirements, the CAISO will validate the annual and monthly LSE Flexible RA Capacity Plans for that Local Regulatory Authority’s jurisdictional Load Serving Entities, and will use the Effective Flexible Capacity value for each resource calculated under Section 40.10.4. The CAISO will determine whether each Load Serving Entity met its annual or monthly total Flexible RA Capacity Requirement, and for the monthly LSE Flexible RA Capacity Plan, whether it met the total monthly requirement within the minimum or maximum quantity, as applicable, for each Flexible Capacity Category.

(2) If the Local Regulatory Authority has established its own flexible capacity procurement requirements, the CAISO will not validate the individual LSE Flexible Capacity Plans for that Local Regulatory Authority’s jurisdictional Load Serving Entities.

(b) **Identification of Discrepancy.** The CAISO will compare all LSE Flexible RA Capacity Plans and Resource Flexible RA Capacity Plans to identify any discrepancy in the Resource Adequacy Resources listed or the amount of the Resource Adequacy Capacity committed.

(c) **Evaluation for Cumulative Deficiency.**

(1) The CAISO will evaluate the annual LSE Flexible RA Capacity Plans of all Load Serving Entities on a cumulative basis to determine whether the total amount of Flexible RA Capacity shown in the plans meets 90 percent of the annual Flexible Capacity Need determined by the CAISO pursuant to Section 40.10.1 or whether a cumulative deficiency may exist under Section 43A.2.7(a).

(2) The CAISO will evaluate the monthly Flexible RA Capacity Plans of all Load Serving Entities to determine whether (i) the total amount of Flexible RA Capacity shown in the plans, limited to the maximum monthly requirement for each category, meets the applicable monthly Flexible Capacity Need determined by the CAISO pursuant to Section 40.10.1 or whether a cumulative deficiency may exist under Section 43A.2.7(b)(1); or (ii) the total amount of Flexible RA Capacity shown in the base ramping Flexible Capacity Category in the plans meets the minimum monthly requirement for the base ramping Flexible Capacity Category determined by the CAISO pursuant to Section 40.10.1.5 or whether a cumulative deficiency may exist under Section 43A.2.7(b)(2).

(d) **Calculation of Flexible RA Capacity.** The CAISO will calculate the amount of Flexible RA Capacity included in the annual and monthly Flexible RA Capacity Plans using the MW amount of Flexible RA Capacity for each resource designated in a plan as a Flexible RA Capacity Resource up to the Effective Flexible Capacity value for the resource calculated under Section 40.10.4.

(e) **Allocated Flexible RA Capacity Requirement.** The CAISO will calculate the Load Serving Entity’s allocated annual and monthly Flexible RA Capacity Requirement –

(1) For Load Serving Entities within a Local Regulatory Authority that has not adopted its own allocation methodology, the CAISO will calculate the Load Serving Entity’s allocated requirement based on the CAISO’s allocation methodology set forth in Section 40.10.2.

(2) For Load Serving Entities within a Local Regulatory Authority that has adopted its own allocation methodology, the CAISO will use that Local Regulatory Authority’s methodology for the Local Regulatory Authority’s jurisdictional Load Serving Entities.

**40.10.5.4 Deficiency in LSE Flexible RA Capacity Plan**

(a) **Finding and Notification.** If the CAISO’s validation under Section 40.10.5.3(a) finds either: (i) that the total amount of Flexible RA Capacity included in an annual or monthly LSE Flexible RA Capacity Plan is not sufficient to satisfy the Load Serving Entity’s allocated Flexible RA Capacity Requirement; or (ii) that the total monthly requirement in a monthly LSE Flexible RA Capacity Plan was not met within the minimum or maximum quantity, as applicable, for each Flexible Capacity Category, the CAISO will –

(1) notify the relevant Scheduling Coordinator, and the Local Regulatory Authority or federal agency with jurisdiction over the relevant Load Serving Entity, in an attempt to resolve any deficiency in accordance with the procedures set forth in the Business Practice Manual; and

(2) provide the notice at least 40 days in advance of the first day of the month covered by the plan and include the reasons the CAISO believes a deficiency exists.

(b) **Resolved Discrepancy.** If the CAISO issues a notice of discrepancy under Section 40.10.5.5(a) and the discrepancy is resolved, the Scheduling Coordinator must provide the CAISO with a revised LSE Flexible RA Capacity Plan or Resource Flexible RA Capacity Plan, as applicable, no less than 11 days prior to the first day of the month covered by the plans.

(1) demonstrate, no less than 30 days prior to the first day of the month covered by the LSE Flexible RA Capacity Plan, that the identified deficiency is cured by submitting a revised LSE Flexible RA Capacity Plan, or

(2) advise the CAISO that the Load Serving Entity’s Local Regulatory Authority, or federal agency, as appropriate, has determined that no deficiency exists.

(c) **Unresolved Deficiency.** If the CAISO issues a notice of deficiency under Section 40.10.5.4(a) and is not advised that the deficiency is resolved, the CAISO will use the information contained in the Resource Flexible RA Capacity Plan to set the obligations of resources under Section 40.10 and/or to assign any costs incurred under this Section 40 and Section 43A.

**40.10.5.5 Discrepancy Between Flexible RA Capacity Plans.**

(a) **Finding and Notification.** If the CAISO’s review under Section 40.10.5.3(b) finds a discrepancy between an LSE Flexible RA Capacity Plan and a Resource Flexible RA Capacity Plan, the CAISO will –

(1) notify the relevant Scheduling Coordinators of the discrepancy in an attempt to resolve the discrepancy in accordance with the procedures set forth in the Business Practice Manual; and

(2) provide the notice at least 40 days in advance of the first day of the month covered by the plans and include the reasons the CAISO believes a discrepancy exists.

(b) **Resolved Discrepancy.** If the CAISO issues a notice of discrepancy under Section 40.10.5.5(a) and the discrepancy is resolved, the Scheduling Coordinator must provide the CAISO with a revised LSE Flexible RA Capacity Plan or Resource Flexible RA Capacity Plan, as applicable, no less than 30 days prior to the first day of the month covered by the plans.

(c) **Unresolved Discrepancy.** If the CAISO issues a notice of discrepancy under Section 40.10.5.5(a) and is not advised that the discrepancy is resolved, the CAISO will use the information contained in the Resource Flexible RA Capacity Plan to set the obligations of resources under Section 40.10 and/or to assign any costs incurred under this Section 40 and Section 43A.

**40.10.5.6 LRA Deficiency**

(a) **Finding and Notification.** If the CAISO’s evaluation under Section 40.10.5.3(c) finds a cumulative deficiency in Flexible RA Capacity, the CAISO will –

(1) identify each Local Regulatory Authority that did not meet its allocable share of the Flexible Capacity Need using the cumulative amount of Flexible RA Capacity that the Local Regulatory Authority’s jurisdictional Load Serving Entities included in their annual and monthly Flexible RA Capacity Plans in total and, for the monthly Flexible RA Capacity Plans, in each Flexible Capacity Category;

(2) identify each Load Serving Entity that: (i) is subject to the jurisdiction of a Local Regulatory Authority that did not meet its allocable share of the Flexible Capacity Need under Section 40.10.5.6; and (ii) did not include sufficient Flexible RA Capacity in an annual or monthly plan to meet its allocated Flexible RA Capacity Requirement or did not meet the monthly requirement within the minimum or maximum quantity, as applicable, for each Flexible Capacity Category, based on the allocation methodology of the Local Regulatory Authority if it has established its own methodology for allocating the Flexible Capacity Need to its jurisdictional Load Serving Entities;

(3) notify each Local Regulatory Authority identified under Section 40.10.5.6(a)(1) and the Scheduling Coordinator for each Load Serving Entity identified under Section 40.10.5.6(a)(2) of the cumulative deficiency in an attempt to resolve any deficiency in accordance with the procedures set forth in the Business Practice Manual; and

(4) provide the notice at least 40 days in advance of the first day of the month covered by the plan and include the reasons the CAISO believes a cumulative deficiency exists.

(b) **Resolved Deficiency.** If the CAISO provides a notice of cumulative deficiency under Section 40.10.5.6(a), and the deficiency is resolved, the Scheduling Coordinator for the Load Serving Entity shall demonstrate, no less than 30 days prior to the first day of the month covered by the LSE Flexible RA Capacity Plan, that the identified deficiency is cured by submitting a revised LSE Flexible RA Capacity Plan.

(c) **Unresolved Deficiency.** If the CAISO provides a notice of deficiency under Section 40.10.5.6(a) and is not advised that the deficiency is resolved, the CAISO will use the information contained in the Resource Flexible RA Capacity Plan to set the obligations of resources under Section 40.10 and/or to assign any costs incurred under this Section 40 and Section 43A.

### 40.10.6 Flexible RA Capacity Must-Offer Obligation

**40.10.6.1 Day-Ahead and Real-Time Availability**

(a) **Must-Offer Obligation.** The Scheduling Coordinator for a resource supplying Flexible RA Capacity must submit Economic Bids for Energy for the full amount of the resource’s Flexible RA Capacity, Bids for IRU and IRD for the full amount of the resource’s Flexible RA Capacity that is eligible to Bid for Imbalance Reserves, and Economic Bids for Ancillary Services that are not flagged as Contingency Only in the Day-Ahead Market for the full amount of the resource’s Flexible RA Capacity that is certified to provide Ancillary Services, in the Day-Ahead Market and the Real-Time Market for the applicable Trading Hours that is capable of being economically dispatched as follows, except as provided in Section 40.10.6.1(e) through(h) –

(1) Flexible Capacity Category for base ramping resources - the 17-hour period from 5:00 a.m. to 10:00 p.m., seven days a week;

(2) Flexible Capacity Category for peak ramping resources - the five-hour period determined for each season by the CAISO’s Flexible Capacity Needs Assessment, seven days a week; and

(3) Flexible Capacity Category for super-peak ramping resources – the five-hour period determined for each season by the CAISO’s Flexible Capacity Needs Assessment, weekdays, except holidays and as provided in Section 40.10.6.1(h), until the resource receives during the five-hour period of the must offer obligation and responds to five CAISO dispatches for Start-Up during the month, after which the resource will not be subject to a must-offer obligation as a super-peak ramping resource for the remainder of that month; however, any other must-offer obligations for Resource Adequacy Capacity will still apply.

(b) **Availability Requirement.** During the period of the applicable must-offer obligation, a Flexible RA Capacity Resource must be operationally available except for limitations specified in the Master File, legal or regulatory prohibitions or as otherwise required by this CAISO Tariff or by Good Utility Practice.

(c) **Co-optimization.** Through the IFM co-optimization process, the CAISO will utilize available Flexible RA Capacity to provide Energy, Imbalance Reserves, or Ancillary Services in the most efficient manner to clear the Energy market, manage congestion and procure required Ancillary Services.

(d) **Participation in RUC.** A Flexible RA Capacity Resource must submit RUC Availability Bids for RCU for their Flexible RA Capacity.

(e) **Use-Limited Resources.**

(1) A Use-Limited Resource providing Flexible RA Capacity must be capable of responding to Dispatch Instructions and, consistent with its use-limitations, must submit Economic Bids for Energy for the full amount of its Flexible RA Capacity in the Day-Ahead Market and the Real-Time Market for the Trading Hours applicable to the resource’s Flexible Capacity Category for that month for the Trading Hours that it is capable of being economically dispatched.

(2) The Scheduling Coordinator for the Use-Limited Resources designated as a combined resource under Section 40.10.3.2(b), 40.10.3.3(b) or 40.10.3.4(b) must submit Economic Bids for Energy for either resource for the full amount of the Flexible RA Capacity required by the applicable must-offer obligation; however, Economic Bids for Energy must be submitted for only one resource in the combination per Trade Day.

(f) **Short or Long Start Units.**

(1) Short Start Units providing Flexible RA Capacity that do not have an IFM Schedule or a RUC Schedule for any of their Resource Adequacy Capacity for a given Trading Hour are required to participate in the Real-Time Market consistent with the provisions in Section 40.6.2 that apply to Short Start Units providing RA Capacity.

(2) Long Start Units providing Flexible RA Capacity that do not have an IFM Schedule or a RUC Schedule for any of their Resource Adequacy Capacity for a given Trading Hour are required to participate in the Real-Time Market consistent with the provisions in Section 40.6.2 that apply to Long Start Units providing RA Capacity.

(3) If availability is required under Section 40.6.2, the Scheduling Coordinator for the resource must submit to the RTM for that Trading hour for which the resource is capable of responding to Dispatch Instructions: (i) Economic Bids for Energy for the full amount of the available Flexible RA Capacity, including capacity for which it has submitted Economic Bids for Ancillary Services; and (ii) Economic Bids for Ancillary Services for the full amount of its Flexible RA Capacity that is certified to provide Ancillary Services and that did not receive a day-ahead award, and for each Ancillary Service for which the resource is certified, including capacity for which it has submitted Economic Bids for Energy.

(g) **Extremely Long-Start Resources.** Flexible RA Capacity Resources that are Extremely Long-Start Resources must be available to the CAISO by complying with the Extremely Long-Start Commitment Process under Section 31.7 or otherwise committing the resource upon instruction from the CAISO, if physically capable. Once an Extremely Long-Start Resource is committed by the CAISO, it is subject to the provisions of Section 40.10.6 regarding Day-Ahead Availability and Real-Time Availability for the Trading Days for which it was committed.

(h) **Non-Generator Resources, Regulation Energy Management.** Non-Generator Resources providing Flexible RA Capacity and Regulation Energy Management must submit Economic Bids for Regulation Up and Regulation Down for Trading Hours in the 17-hour period from 5:00 a.m. to 10:00 p.m., seven days a week and shall not submit Bids for Energy or other Ancillary Services.

**40.10.6.2 Failure to Bid**

If the Scheduling Coordinator for a resource supplying Flexible RA Capacity does not submit Economic Bids for Energy for the full amount of the resource’s Flexible RA Capacity, and Economic Bids for Ancillary Services for the full amount of the resource’s Flexible RA Capacity that is certified to provide Ancillary Services, in the Day-Ahead Market and the Real-Time Market for the Trading Hours during the period of the applicable must-offer obligation –

(1) the CAISO will not insert Generated Bids for any Flexible RA Capacity for which the resource did not submit bids; and

(2) An Exceptional Dispatch instruction issued to the resource for all or a portion of its Flexible RA Capacity shall not be an Exceptional Dispatch CPM designation under Section 43A.2.5.

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# 44. Flexible Ramping Product

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## 44.3 Forecasted Movement

### 44.3.1 Generally

The CAISO will determine the Forecasted Movement for each EIM Participating Resource, Generating Unit, System Resource, Pumped Storage, Pseudo-Tie, Non-generating Resource, PDR, Participating Load, and any other resource that has a schedule or dispatch change in the Day-Ahead Market or Real-Time Market as described below.

### 44.3.2 RTD Forecasted Movement

For the RTD, the Forecasted Movement for the resource is the MW difference between the resource’s non-binding dispatch instruction in the first five-minute advisory RTD interval and its Dispatch Instruction in the financially binding RTD interval, in the same RTD run.

### 44.3.3 FMM Forecasted Movement

For FMM, the Forecasted Movement is the difference between the resource’s advisory FMM schedule in the first advisory FMM interval and its FMM Schedule in the financially binding FMM interval for the same applicable FMM run.

### 44.3.4 DAM Forecasted Movement

For DAM, the Forecasted Movement is the algebraic difference of the Day-Ahead Schedule between consecutive hours.

### 44.3.5 Virtual Forecasted Movement

For Virtual Awards, the Forecasted Movement is the algebraic difference of the Virtual Award between consecutive hours.

### 44.3.6 Base Schedule Forecasted Movement

For EIM Base Schedules, the Forecasted Movement is the algebraic difference of the submitted EIM Base Schedule, as adjusted in real time, between consecutive hours.

\* \* \*

# Appendix A – Amended Terms

## - Bid

Either (1) an offer, including a Self-Schedule, submitted by a Scheduling Coordinator for a specific resource, conveyed through several components that apply differently to the different types of service offered to or demanded from any of the CAISO Markets for the Demand of Energy or the supply of Energy, Imbalance Reserves, Reliability Capacity, or Ancillary Services ; or (2) a Virtual Bid.

## - Bid Costs

The costs for resources manifested in the Bid components submitted, which include the Start-Up Bid Cost, Minimum Load Bid Cost, Energy Bid Cost, Transition Bid Cost, Pump Shut-Down Cost, Pumping Cost, Ancillary Services Bid Cost, RUC Availability Payment, and Imbalance Reserves Costs

## - CAISO Protocols

The rules, protocols, procedures and standards promulgated by the CAISO (as amended from time to time) to be complied with by the CAISO, Scheduling Coordinators, Participating TOs and all other Market Participants in relation to the operation of the CAISO Controlled Grid and the participation in the CAISO Markets in accordance with the CAISO Tariff.

## - Day-Ahead Schedule

A Schedule issued by the CAISO one day prior to the target Trading Day indicating the levels of Supply and Demand for Energy cleared through the IFM and scheduled for each Settlement Period, for each PNode or Aggregated Pricing Node, including Scheduling Points of that Trading Day.

## - Day-Ahead Scheduled Energy

Hourly Energy that corresponds to the flat portions of the hourly Day-Ahead Schedule. It is composed of Day-Ahead Minimum Load Energy, Day-Ahead Self-Scheduled Energy, and Day-Ahead Bid Awarded Energy. It does not include the Day-Ahead Energy that corresponds to the flat schedule when a resource is committed in the Day-Ahead in pumping mode. Expected Energy committed in Day-Ahead pumping mode is accounted for as Day-Ahead Pumping Energy. Day-Ahead Scheduled Energy is settled as specified in Section 11.2.1.1.

## - Forecasted Movement

A resource's change or Virtual Award’s change in forecasted output between market intervals as described in Section 44.3.

## - Generator

The seller of Energy, Imbalance Reserves, Reliability Capacity, or Ancillary Services produced by a Generating Unit.

## - IFM Bid Cost

The sum of a BCR Eligible Resource’s IFM Start-Up Cost, IFM Minimum Load Cost , IFM Pump Shut-Down Cost, IFM Transition Cost, IFM Pumping Cost, IFM Energy Bid Cost, IFM AS Bid Cost and IFM Imbalance Reserves Cost.

## - Marginal Cost of Congestion (MCC)

The component of LMP, Locational IRU Price, Locational IRD Price, Locational RCU Price, or Locational RCD Price at a PNode that accounts for the cost of congestion, as measured between that Node and a Reference Bus.

## - Notional CRR Value

For a given CRR in a Settlement Period, the sum of: (1) the product of: (a) the MCC of Energy at the CRR Sink minus the MCC of Energy at the CRR Source and (b) the MW quantity for that Settlement Period; (2) the product of (a) the MCC of Locational IRU Price at the CRR Sink minus the MCC of Locational IRU Price at the CRR Source and (b) the MW quantity for that Settlement Period; and (3) the product of (a) the MCC of Locational IRD Price at the CRR Sink minus the MCC of Locational IRD Price at the CRR Source and (b) the MW quantity for that Settlement Period. The Notional CRR Value for a CRR Obligation can be a non-positive value for a Settlement Period but cannot be less than zero (0) for a CRR Option.

## - Participating Generator

A Generator or other seller of Energy, Imbalance Reserves, Reliability Capacity, or Ancillary Services through a Scheduling Coordinator over the CAISO Controlled Grid (1) from a Generating Unit with a rated capacity of 1 MW or greater, (2) from a Generating Unit with a rated capacity of 500 kW up to 1 MW for which the Generator elects to be a Participating Generator, (3) from a storage resource with a rated capacity of 100 kW or greater, or (4) from a Generating Unit providing Ancillary Services or submitting Energy Bids through an aggregation arrangement approved by the CAISO, which has undertaken to be bound by the terms of the CAISO Tariff, in the case of a Generator through a Participating Generator Agreement, Net Scheduled PGA, or Pseudo-Tie Participating Generator Agreement.

## - Residual Unit Commitment (RUC)

The process conducted by the CAISO in the Day-Ahead Market after the IFM has been executed to address mismatches between the CAISO Forecast of BAA Demand and the physical resources committed in the IFM.

## - RMR Dispatch

The quantity of Energy, Imbalance Reserves, Reliability Capacity, or Ancillary Services that is mandated by the CAISO to be delivered in a given market for a resource by a Legacy RMR Unit under a Legacy RMR Contract or by an RMR Resource under an RMR Contract.

## - RUC Availability Bid

The quantity (MW) and price ($/MW per hour) at or above which a Generating Unit, System Resource, System Unit, Participating Load, or Proxy Demand Resource has agreed to sell RUC Capacity for a specified interval of time to the CAISO to meet the Residual Unit Commitment requirement.

## - RUC Award

The quantity of RCU or RCD awarded to a resource by the RUC for a Settlement Period.Interval for all BCR Eligible Resources with Unrecovered Bid Cost Uplift Payments. This amount will be netted according to Section 11.8.6.2 to calculate the Net RUC Bid Cost Uplift before allocation to Scheduling Coordinators.

## - RUC Capacity

RCU or RCD.

## - RUC Price

The price calculated by the RUC optimization for each Trading Hour of the next Trading Day for RCU and RCD, separately, which reflects the price ($/MW per hour) for the next increment of either RCU or RCD at a specified PNode for each Trading Hour.

The Locational RCU Price or Locational RCD Price

## - RUC Schedule

## The net of Day-Ahead Schedule and the RUC Award in a given hour.- RUC Zone

A forecast region representing a UDC or MSS Service Area, Local Capacity Area, or other collection of Nodes for which the CAISO has developed sufficient historical CAISO Demand and relevant weather data to perform a Demand Forecast for such area, for which as further provided in Section 31.5.3.2 the CAISO may adjust the CAISO Forecast of BAA Demand to ensure that the RUC process produces adequate local capacity procurement.

## - Undeliverable Capacity

Ancillary Services capacity that was dispatched by the CAISO to provide Energy but where a certain percentage or more of the Expected Energy was not provided in Real-Time, which percentage is determined as specified in the applicable Business Practice Manual.

## - Wholesale Customer

A person wishing to purchase Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services at a Bulk Supply Point or a Scheduling Point for resale.

## - Wholesale Sales

The sale of Energy, Imbalance Reserves, Reliability Capacity, and Ancillary Services at a Bulk Supply Point or a Scheduling Point for resale.

# Appendix A – New Terms

## - Competitive Locational IRU Price

The Locational IRU Price minus the non-competitive congestion components in the upward deployment scenario, as calculated pursuant to Section 31.2.1.

## - Competitive RUC Price for RCU

The RUC Price for RCU minus the non-competitive congestion components in the upward deployment scenario, as calculated pursuant to Section 31.9.1.

## - DAME Transition Period

The three-year period that starts on the first Trading Day for which the CAISO procures either Imbalance Reserves or Reliability Capacity.

## - DAME Transitional Measures

As specified in Section 11.2.6, the settlement provisions through which the CAISO shares the revenue of an Imbalance Reserves Award or Reliability Capacity Award to a Resource Adequacy Resource with the Scheduling Coordinator of the resource and the Scheduling Coordinator for the LSE that showed that resource on its Supply Plan

## - Deployment Factor

The percentage of Imbalance Reserves Awards specified in the Business Practice Manual the CAISO models as being deployed for Energy for the purpose of modeling the deployment of Imbalance Reserves against Transmission Constraints. The CAISO establishes distinct Deployment Factors for Imbalance Reserves Up and Imbalance Reserves Down.

## - Downward Imbalance Reserves Requirement

## The extreme percentile of downward forecast error of the confidence interval described in Section 31.3.1.6.1.- Five-Minute Imbalance Reserve Quantity

For a resource with an Imbalance Reserves Award, the five-minute ramp capable portion of the award measured as the MW quantity of the resource’s ramp capability above the Day-Ahead hourly Energy schedule, in the case of IRU, or below that schedule, in the case of IRD. The ramp capability is determined based on the Master File-registered ramp rate used to optimize the day-ahead market.

## - Flexible Ramping Product

The product procured pursuant to Section 44 to meet flexible ramping needs to meet Forecasted

Movement and Uncertainty Requirements.

## - IFM Imbalance Reserves Cost

The Bid Costs of a Bid for Imbalance Reserves, as calculated pursuant to Section 11.8.2.1.8.

## - Imbalance Reserves

IRU and IRD

## - Imbalance Reserves Award

IRD and IRU awarded to a resource for a given fifteen-minute interval.

## - Imbalance Reserves Bid

The quantity (MW) and price ($/MW per hour) at or above which a Generating Unit, System Resource, System Unit, Participating Load, or Proxy Demand Resource has agreed to sell IRU or IRD for a specified interval of time to the CAISO to meet the Imbalance Reserves Requirement.

## - Imbalance Reserves Cost

The costs included in a bid to provide Imbalance Reserves submitted per Section 30.5.2.9 and as modified pursuant to Section 30.7.3

## - Imbalance Reserves Down (IRD)

Decremental capacity procured to meet the Downward Imbalance Reserves Requirement.

## - Imbalance Reserves Requirement

## The Upward Imbalance Reserves Requirement and the Downward Imbalance Reserves Requirement- Imbalance Reserves Up (IRU)

Incremental capacity procured to meet the Upward Imbalance Reserves Requirement.

## - IRU Default Availability Bid

The price to which an Imbalance Reserves Bid for IRU is mitigated, as specified in Section 39.7.4.

## - IRU Negotiated Availability Bid

A method of calculating an IRU Default Availability Bid based on a negotiation with the CAISO pursuant to Section 39.7.4.1.

## - Locational IRD Price

The marginal cost ($/MWh) of providing the next increment of IRD at a PNode consistent with binding Transmission Constraints.

## - Locational IRU Price

The marginal cost ($/MWh) of providing the next increment of IRU at a PNode consistent with binding Transmission Constraints.

## - Locational RCD Price

The marginal cost ($/MWh) of providing the next increment of RCD at a PNode consistent with binding Transmission Constraints.

## - Locational RCU Price

The marginal cost ($/MWh) of providing the next increment of RCU at a PNode consistent with binding Transmission Costraints.

## - Lower Economic Limit

The higher of a resource’s Self-Schedule quantity or Minimum Load. For a Non-Generator Resource, the Lower Economic Limit is the MW quantity at the bottom of the submitted Energy Bid Curve.

## - Negotiated Availability Bid

Either an IRU Negotiated Availability Bid or an RCU Negotiated Availability Bid.

## - Net Load Forecast

The demand forecast for a BAA minus the forecast of wind and solar output for the BAA during the interval.

## - Non-VER Physical Supply

The physical supply of Energy available to the CAISO net of potential Supply from VERs electrically located in an EDAM Entity.

## - RCD Availability Quantity

A RCD Award (MW) excluding any RCD Capacity that is actually unavailable due to a unit derate or Outage.

## - RCU Availability Quantity

A RCU Award (MW) excluding any RCU Capacity that is actually unavailable due to a unit derate or Outage.

## - RCU Default Availability Bid

The price to which an RUC Availability Bid for RCU is mitigated, as specified in Section 39.7.4.

## - RCU Negotiated Availability Bid

## A method of calculating an RCU Default Availability Bid based on a negotiation with the CAISO pursuant to Section 39.7.4.1.- Reliability Capacity

RCU and RCD

## - Reliability Capacity Down (RCD)

Decremental capacity procured to meet any negative difference between Net Load Forecast and Non-VER Physical Supply with a market award.

## - Reliability Capacity Up (RCU)

Incremental capacity procured to meet any positive difference between the Net Load Forecast and Non-VER Physical Supply with a market award.

## - RUC Procurement Target

The quantity of either RCU or RCD the CAISO procures of behalf of each EDAM Entity or the CAISO, as specified in Sections 31.5.3 and 31.5.4.

## - Upper Economic Limit

The highest operating level submitted in a resource’s Energy Bid.

## - Upward Imbalance Reserves Requirement

The extreme percentile of upward forecast error of the confidence interval described in Section 31.3.1.6.1.

# Appendix CLocational Marginal Price

[Incremental edits to Appendix C related to price formulation for locational prices for IRU/IRD/RCU/RCD have been included in draft tariff published for the Extended Day-Ahead Market initiative]

\* \* \*

# Appendix F Rate Schedules

**Schedule 1**

**Grid Management Charge**

**Part A – Monthly Calculation of Grid Management Charge (GMC)**

The GMC consists of the following separate service charges: (1) the Market Services Charge; (2) the System Operations Charge; and (3) the CRR Services Charge. The GMC revenue requirement, determined in accordance with Part C of this Schedule 1, shall be allocated to the service charges specified in Part A of this Schedule 1 as follows: forty-nine (49) percent to Market Services; forty-nine (49) percent to System Operations; and two (2) percent to CRR Services. Starting in 2017 and every three (3) years thereafter, the CAISO will conduct an updated cost of service study, in consultation with stakeholders and using costs from the previous year. In conducting each cost of service study, the CAISO will recalculate the three service charge percentages and the rates for the fees and charges that constitute the Grid Management Charge as set forth in Section 11.22. In addition, the cost of service study results will be used to update the RC Funding Percentage used to calculate the annual RC Funding Requirement, as well as the real time percentages of the Market Services and System Operations service charges used to calculate the EIM Administrative Charges. If, based on the cost of service study results, the service category revenue requirement allocation percentages or the level of fees and charges have changed, the CAISO will submit tariff amendments to reflect such changes pursuant to Section 205 of the FPA.

1. The rate for the Market Services Charge will be calculated by dividing the annual GMC revenue requirement allocated to this service category by the forecast annual gross absolute value of MW per hour of Ancillary Services capacity awarded in the Day-Ahead and Real-Time Markets, MWh of Energy cleared in the Day-Ahead market, MWh of Imbalance Reserves cleared in the Day-Ahead market, MWh of Reliability capacity cleared in the Day-Ahead market, Virtual Demand Award, Virtual Supply Award, and FMM Instructed Imbalance Energy and RTD Instructed Imbalance Energy, less the forecast annual gross absolute value of such Energy as may be excluded for a load following MSS pursuant to an MSS agreement, Standard Ramping Energy, Regulation Energy, Ramping Energy Deviation, Residual Imbalance Energy, Exceptional Dispatch Energy and Operational Adjustments for the Day-Ahead and Real-Time.

2. The rate for the System Operations Charge will be calculated by dividing the annual GMC revenue requirement allocated to this service category by forecast annual gross absolute value of MWh of real-time energy flows on the ISO Controlled Grid, net of amounts excluded pursuant to Part E of this Schedule.

3. The rate for the CRR Services Charge will be calculated by dividing the annual GMC revenue requirement allocated to this service category by the forecast annual sum of awarded MW of CRRs per hour.

The rates for the foregoing charges shall be adjusted automatically each year, effective January 1 for the following twelve (12) months, in the manner set forth in Part D of this Schedule.