30. BIDS AND BID SUBMISSION FOR ALL CAISO MARKETS

~~30 BIDS AND BID SUBMISSION.~~

~~30.1 ISO Operations.~~

30.1 Bids

Scheduling Coordinators shall submit Bids to participate in the CAISO Markets, including any Self-Schedules, ETC Self-Schedules or Self-Provision of Ancillary Services. Bids submitted in the DAM apply to the 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. Scheduling Coordinators may submit Bids for the DAM as early as 7 days ahead of the targeted Trading Day. Bids submitted in the HASP apply to a single Trading Hour and are used in the HASP and the RTM. 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 Scheduling.~~

~~30.1.3 ISO Scheduling Responsibilities.~~

~~To fulfill its obligations with respect to scheduling Energy and Ancillary Services, the ISO shall:~~

~~(a) provide Scheduling Coordinators with operating information and system status on a Day-Ahead and Hour-Ahead, Zonal and/or Scheduling Point basis to enable Scheduling Coordinators to optimize Generation, Demand and the provision of Ancillary Services;~~

~~(b) determine whether Preferred Schedules submitted by Scheduling Coordinators meet the requirements of Section 4.5.4.2, and whether they will cause Congestion;~~

~~(c) prepare Suggested Adjusted Schedules on a Day-Ahead basis and Final Schedules on a Day-Ahead and Hour-Ahead basis;~~

~~(d) validate all Ancillary Services bids and self-provided Ancillary Services;~~

~~(e) reduce or eliminate Inter-Zonal Congestion based on Adjustment Bids and in accordance with the Congestion Management procedures, and Intra-Zonal Congestion in accordance with Section 27.1.1.6; and~~

~~(f) if necessary, make mandatory adjustments to Schedules in accordance with the Congestion Management procedures.~~

30.2 Bid Types

There are three types of Bids: Energy Bids, Ancillary Services Bids, and RUC Availability Bids. Each Bid type can be submitted as either an Economic Bid or a Self-Schedule. 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, may be either Supply Bids or Demand Bids. Ancillary Services Bids and RUC Availability 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 three 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]~~30.2 Information to Be Submitted by Scheduling Coordinators to the ISO.~~

~~Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules Document, which contains the format for submission of Schedules and bids.Each Preferred Schedule submitted by a Scheduling Coordinator shall represent its preferred mix of Generation to meet its Demand and account for Transmission Losses and must include the name and identification number of each Eligible Customer for whom a Demand Bid or an Adjustment Bid is submitted, as well as:~~

~~**30.2.1 For Demand:**~~

~~**30.2.1.1 Designated Location Code.** For all Demand the Location Code of the Take-Out Point (which must be the name of a Demand Zone, Load group or bus);~~

~~**30.2.1.2 Quantity at Take-Out Point.** The aggregate quantity (in MWh) of Demand being served at each Take-Out Point for which a bid has been submitted;~~

~~**30.2.1.3 Flexibility.** Whether the Preferred Schedule is flexible for adjustment to eliminate Congestion;~~

~~**30.2.1.4 Adjustment Bids.** The MW and $/MWh values representing the Adjustment Bid curve for any Dispatchable Load;~~

~~**30.2.1.5** Scheduling Coordinator's ID code;~~

~~**30.2.1.6** type of market (Day-Ahead or Hour-Ahead) and Trading Day;~~

~~**30.2.1.7** type of Schedule: Preferred or Revised;~~

~~**30.2.1.8** hourly scheduled MWh for each Settlement Period of the Trading Day that uses the Existing Contract (which values should be less than or equal to the values indicated in (i) 30.2.1.12 below);~~

~~**30.2.1.9** **Congestion Management flag.** "Yes" indicates that any Adjustment Bid submitted for a Dispatchable Load under item 30.2.1.12 below should be used;~~

~~**30.2.1.10** publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, "Yes" will indicate that the Scheduling Coordinator wishes the ISO to publish its Adjustment Bids;~~

~~**30.2.1.11** hourly scheduled MWh, including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule);~~

~~**30.2.1.12** the MW and $/MWh values for each Dispatchable Load for which an Adjustment Bid is being submitted;~~

~~**30.2.1.13** requisite NERC tagging data.~~

~~**30.2.2** **For Generation:**~~

~~**30.2.2.1** **Location of Generating Units.** The Location Code of all Generating Units scheduled, if applicable, or the source Control Area and Scheduling Point;~~

~~**30.2.2.2** **Quantity Scheduled.** The aggregate quantity (in MWh) being scheduled from each Generating Unit and System Resource;~~

~~**30.2.2.3** **Notification of Flexibility.** Notification of whether the Preferred Schedule is flexible for adjustment to eliminate Congestion;~~

~~**30.2.2.4** **Adjustment Bids.** The MW and $/MWh values representing the Adjustment Bid curve for each Generating Unit and System Resource for which an Adjustment Bid has been submitted;~~

~~**30.2.2.5** **Operating Characteristics.** Operating characteristics for each Generating Unit and System Resource for which an Adjustment Bid has been submitted; and~~

~~**30.2.2.6** **Must-Take/Must-Run Generation.** Identification of all scheduled Generating Units that are Regulatory Must-Take Generation or Regulatory Must-Run Generation.~~

~~**30.2.2.7** Scheduling Coordinator's ID code;~~

~~**30.2.2.8** type of market (Day-Ahead or Hour-Ahead) and Trading Day;~~

~~**30.2.2.9** name of Generating Unit scheduled;~~

~~**30.2.2.10** type of Schedule: Preferred or Revised;~~

~~**30.2.2.11** priority type, if applicable, to the Settlement Period (use OTHER if scheduling the use of Existing Contract rights or RLB_MUST_RUN) for Reliability Must-Run Generation;~~

~~**30.2.2.12** contract reference number for Reliability Must-Run Generation;~~

~~**30.2.2.13** **Transmission loss self-provision flag (LOSS CMP FLG):** "Yes" indicates that Dispatch Instructions provided to the Generating Unit will include Transmission Losses associated with the unit's Final Hour-Ahead Schedule as determined by the relevant GMM;~~

~~**30.2.2.14** **Congestion Management flag.** "Yes" indicates that any Adjustment Bid submitted under 30.2.2.15 should be used in the Day-Ahead or Hour-Ahead Market;~~

~~**30.2.2.14A** **Publish Adjustment Bid flag, which will not be functional on the ISO Operations Date.** In the future, "Yes" will indicate that the Scheduling Coordinator wishes the ISO to publish its Adjustment Bids;~~

~~**30.2.2.15** Generating Unit ramp rate in MW/minute;~~

~~**30.2.2.16** hourly scheduled Generating Unit output in MWh (the ISO will multiply these values by the hourly Generation Meter Multipliers), including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule);~~

~~**30.2.2.17** The MW and $/MWh values for each Generating Unit for which an Adjustment Bid is being submitted.~~

~~**30.2.2A** The Generation section of a Balanced Schedule, and any associated Adjustment Bids, must accurately reflect the physical capability of each Generating Unit identified in the Schedule (including each Generating Unit's ability to ramp from one hour to the next). For example, a 500 MW Generating Unit specified with a ramp rate of 2 MW/min and an operating point of 100 MWh for the~~

~~current operating hour is not physically capable of generating 300 MWh in the next operating hour. Likewise, Adjustment Bids submitted for a Generating Unit, applicable to a particular operating hour, should be physically achievable within the applicable operating hour~~

~~.~~

~~**30.2.3 For deliveries to/from other Scheduling Coordinators:**~~

~~In the event of an Inter-Scheduling Coordinator Energy Trade, the Scheduling Coordinators who are parties to that trade must agree on a Zone in which the trade will be deemed to take place and notify the ISO accordingly. The purpose of designating a Zone is to provide for the allocation of Usage Charges which may arise in connection with the trade. The Inter-Scheduling Coordinator Energy Trades section of a Schedule will include the following information for each Inter-Scheduling Coordinator Trade:~~

~~**30.2.3.1 Identification Code.** Identification Code of Scheduling Coordinator to which Energy is provided or from which Energy is received;~~

~~**30.2.3.2 Quantity of Energy.** Quantity (in MWh) of Energy being received or delivered;~~

~~**30.2.3.3 Zone.** The Zone within which Energy is deemed to be provided by one Scheduling Coordinator to another under the Inter-Scheduling Coordinator Energy Trades.~~

~~**30.2.3.4 Adjustments.** Scheduling Coordinators will have the opportunity to resubmit Preferred Schedules and or Revised Schedules upon notice by the ISO if the ISO determines that the quantity or location of the receiving Scheduling Coordinator is not consistent with the quantity or location of the delivering Scheduling Coordinator. If the Scheduling Coordinators involved in a mismatched Inter-Scheduling Coordinator Energy Trade do not submit adjusted Schedules which resolve any mismatch as to quantities and provided that there is no dispute as to whether the mismatched trade occurred or over its location, the ISO will adjust the Schedule containing the higher quantity to match the scheduled quantity of Energy in the other Schedule, except where the Schedule to be reduced contains only Inter-Scheduling Coordinator Energy Trades, in which case the ISO will adjust the other Schedule to match the Schedule containing the higher quantity. If there is a dispute between the Scheduling Coordinators as to whether the Inter-Scheduling Coordinator Energy Trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears. The ISO will then balance the Schedules which are no longer Balanced Schedules by adjusting resources in the relevant Scheduling Coordinator's~~

~~portfolio.~~

~~**30.2.3.5** The Generating Unit or Dispatchable Load that the source or recipient of Energy traded.~~

~~**30.2.3.6** The MW and $/MWh values representing the Adjustment Bid for any Generating Unit or Dispatchable Load that is the source or recipient of Energy traded.~~

~~**30.2.3.7** **[Not Used]**~~

~~**30.2.3.8** type of market (Day-Ahead or Hour-Ahead) and Trading Day;~~

~~**30.2.3.9** trading Scheduling Coordinator (buyer or seller);~~

~~**30.2.3.10** type of Schedule: Preferred or Revised;~~

~~**30.2.3.11** Schedule type – Energy (ENGY);~~

~~**30.2.3.12** hourly scheduled MWh, including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule), with internal imports into the Scheduling Coordinator reported as negative quantities and internal exports from the Scheduling Coordinator reported as positive quantities;~~

~~**30.2.3.13** Congestion Management flag – "Yes" indicates that Adjustment Bid submitted under (k) below should be used:~~

~~**30.2.3.14** publish Adjustment Bid flag – "Yes" indicates that the Scheduling Coordinator wishes the ISO to publish its Adjustment Bid.~~

~~**30.2.4** **For Self-Provided Ancillary Services:**~~

~~Scheduling Coordinators electing to self-provide Ancillary Services shall supply the information referred to in Section 8.6.4 in relation to each Ancillary Service to be self-provided.~~

~~**30.2.5** **For Interruptible Imports:**~~

~~The quantity (in MWh) of Energy categorized as Interruptible Imports and whether the Scheduling Coordinator intends to self-provide the Operating Reserve required by Section 8.2.3.2 to cover such Interruptible Imports or to purchase such Operating Reserve from the ISO.~~

~~**30.2.6** **For External Imports/Exports:**~~

~~The external import/export section of a Balanced Schedule will include the following information for each import or export:~~

~~**30.2.6.1** Scheduling Coordinator's ID code;~~

~~**30.2.6.2** type of market (Day-Ahead or Hour-Ahead) and Trading Day;~~

~~**30.2.6.3** Scheduling Point (the name);~~

~~**30.2.6.4** type of Schedule: Preferred or Revised~~

~~**30.2.6.5** interchange ID (the name of the selling entity, the buying entity, and a numeric identifier);~~

~~**30.2.6.6** Energy type – firm (FIRM), non-firm (NFRM) or dynamic (DYN) or Wheeling (WHEEL);~~

~~**30.2.6.7** external Control Area ID;~~

~~**30.2.6.8** priority type, if applicable, to the Settlement Period (use OTHER if scheduling the use of Existing Contract rights or RLB_MUST_RUN for Reliability Must-Run Generation);~~

~~**30.2.6.9** contract reference number for Reliability Must-Run Generation or Existing Contract (or set of interdependent Existing Contracts);~~

~~**30.2.6.10** contract type – transmission (TRNS), Energy (ENGY) or both (TR_EN);~~

~~**30.2.6.11** Schedule ID (NERC ID number);~~

~~**30.2.6.12** Congestion Management flag – "Yes" indicates that any Adjustment Bid submitted for an external import/export in item (q) below should be used;~~

~~**30.2.6.13** publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, "Yes" will indicate that the Scheduling Coordinator wishes the ISO to publish its Adjustment Bids;~~

~~**30.2.6.14** Complete WECC tag;~~

~~**30.2.6.15** hourly scheduled external imports/exports in MWh (the ISO will multiply these values by the hourly Generation Meter Multipliers), including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule) and with external imports into the ISO Controlled Grid reported as negative quantities and external exports from the ISO Controlled Grid reported as positive quantities;~~

~~**30.2.6.16** the MW and $/MWh values for each external import/export for which an Adjustment Bid is being submitted consistent with Section 30.2.8;~~

~~**30.2.6.17** for dynamically scheduled imports only, the transmission loss self-provision flag (LOSS_CMP_FLG): "Yes" indicates that Dispatch Instructions provided to the resource will include~~

~~Transmission Losses associated with the resource's Final Hour-Ahead Schedule as determined by the relevant GMM.~~

~~30.2.7 Contract Usage Template Associated with a Balanced Schedule that Includes the Use of Existing Contract Rights or Firm Transmission Rights.~~

~~The contract usage template can be submitted seven days in advance. However, the contract usage template will not be validated till the trade day. Each contract usage template must include the following information, in compliance with the ISO Data Templates and Validation Rules document which contains the format for submission of contract usage templates:~~

~~30.2.7.1~~ ~~Scheduling Coordinator's ID code:~~

~~30.2.7.2~~ ~~Type of market (Day-Ahead or Hour-Ahead) and Trading Day;~~

~~30.2.7.3~~ ~~From Zone (must be different than "to Zone"), is the Zone in which all sources specified in the contract usage template must be located;~~

~~30.2.7.4~~ ~~To Zone (must be different than "from Zone"), is the Zone in which all sinks specified in the contract usage template must be located;~~

~~30.2.7.5~~ ~~Contract reference number for each Inter-Zonal Interface for which transmission capacity has been reserved under Existing Contract or Firm Transmission Right. Up to four contract reference numbers can be specified in this field, delimited by commas, for either Existing Contract usage or Firm Transmission Right usage, but not for both (i.e. Existing Contract rights and Firm Transmission Rights cannot be used together in linking sources and sinks on contract usage template). If the use of multiple Inter-Zonal Interfaces are being scheduled, the contract reference numbers must represent a contiguous string of contracts rights from one Zone to the next (although the contract reference numbers need not be listed in any particular order since they will be arranged by the ISO's scheduling program to connect the "from Zone" to "to Zone");~~

~~30.2.7.6~~ ~~Usage ID (a unique identifier that allows a Scheduling Coordinator to submit multiple usages for a given Inter-Zonal Interface);~~

~~30.2.7.7~~ ~~Contract usage, in hourly scheduled MW, for the 24 hours of the Trading Day (for Generators, contract usage can be either positive or negative (i.e., for pumps); for loads, contract usage must be positive; for external imports and inter-Scheduling Coordinator trade imports, contract usage~~

~~must be negative; for external exports, contract usage must be positive). Each contract usage amount must be less than or equal to the amount of Existing Contract rights specified by the relevant Participating Transmission Owner(s) of Firm Transmission Rights, whichever the case may be. Additionally, any Adjustment Bids that may also be submitted for any particular resource (source or sink) that is also identified on a contract usage template must not overlap the contract usages specified for a particular resource in a contract usage template;~~

~~**30.2.7.8** Priority usage, relative to all contract usages specified in a Scheduling Coordinator's Balanced Schedule, as expressed on a scale of one to ten (with 1 having least priority and 10 having highest priority). For Existing Contracts, this priority will be used to adjust usage quantities when scheduled usages exceed the reserved existing transmissions reservations; and~~

~~**30.2.7.9** Sources or sinks, of hourly scheduled MWh (in the case of Energy usages) or MW (in the case of Ancillary Services usages), specified on the contract usage template must be balanced (except for Ancillary Services which need not be specified with sinks). Each Energy schedule or Ancillary Service bid or self-provided schedule associated with a particular source or sink must have an hourly usage schedule that is greater than or equal to the amounts specified on contract usage templates. The source/sink section of a contract usage template will include the following information (up to five combinations of sources and sinks can be specified on a single contract usage template if an Scheduling Coordinator is submitting the templates in accordance with Section 6.4.1A.3, or up to 20 combinations of sources and sinks if an Scheduling Coordinator is submitting the templates in accordance with Section 6.4.1A.3;~~

~~(1) Type of resource – Generation (GEN), load (LOAD), interchange (INTRCHNGE) or inter-Scheduling Coordinator trade (INTER_Scheduling Coordinator);~~

~~(2) Resource_ID – generator_ID, load_ID, tie_point or trading Scheduling Coordinator;~~

~~(3) Resource_ID2 (required only for individual interchange schedules and inter-Scheduling Coordinator trades);~~

~~(4) Energy type – firm (FIRM), non-firm (NFIRM), Wheeling (WHEEL), dynamic (DYN), Energy (ENGY), Spinning Reserve (CSPN), Non-Spinning Reserve (CNSPN) or Replacement Reserve (CRPLC); and~~

~~(5) Hourly scheduled Energy or Ancillary Service, utilizing the same sign convention as set forth in (g) above.~~

~~30.2.8 Content and Format of Adjustment Bids~~

~~**30.2.8.1** Adjustment Bids are contained in Preferred Schedules and Revised Schedules submitted by Scheduling Coordinators for particular Generating Units (including Physical Scheduling Plants), Dispatchable Loads, external imports/exports, and Generating Units and Dispatchable Loads supporting Inter-Scheduling Coordinator Energy Trades. Each Scheduling Coordinator is required to submit a preferred operating point for each Generating Unit, Dispatchable Load and external import/export (these quantities are presented in the Scheduling Coordinator's submitted Schedule as "Hourly MWh"). The Scheduling Coordinator's preferred operating point for each Generating Unit, Dispatchable Load and external import/export must be within the range of any Adjustment Bids to be used by the ISO. The minimum MW output level, which may be zero MW (or negative for pumped storage resources), and the maximum MW output level must be physically achievable.~~

~~**30.2.8.2** Adjustment Bids will be presented in the form of a monotonically non-decreasing staircase function for Generating Units and external imports. Adjustment Bids will be presented in the form of a monotonically non-increasing staircase function for Dispatchable Loads and external exports. These staircase functions will be composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of quantity/price information. Adjustment Bids are submitted as an integral part of the Scheduling Coordinator's Balanced Schedule and must be related to each Generating Unit, Dispatchable Load and external import/export.~~

~~**30.2.9** Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Schedules and bids.~~

~~30.3 The Scheduling Process.~~

~~The ISO scheduling process is described for information purposes only in tabular form in Appendix C. The scheduling process by nature will need constant review and amendment as the market develops and matures and, therefore, is subject to change. The description in Appendix C aids understanding of the implementation and operation of the various markets administered by the ISO and is filed for information purposes only.~~

~~30.3.1 Preferred Schedule.~~

~~A Preferred Schedule is the initial Schedule submitted by a Scheduling Coordinator in the Day-Ahead Market or Hour-Ahead Market. A Preferred Schedule shall be a Balanced Schedule submitted by each Scheduling Coordinator on a daily and/or hourly basis to the ISO. Scheduling Coordinators may also submit to the ISO, Ancillary Services bids in accordance with Section 8.5.2 and, where they elect to self-provide Ancillary Services pursuant to Section 8.6.1, an Ancillary Service schedule meeting the requirements set forth in Section 8.6.4.2A.~~

~~30.3.1A~~ ~~The Preferred Schedule shall also include Adjustment Bids as an indication of which resources (Generation or Load) if any may be adjusted by the ISO to eliminate Congestion. Adjustment Bids will be used by the ISO for Inter-Zonal Congestion Management as described in the SP and are initially valid only for the markets into which they are bid, being the Day-Ahead Market or the Hour-Ahead Market. During the ISO's Day-Ahead scheduling process, in accordance with the SP, the MW range of the Adjustment Bids specified in the Preferred Day-Ahead Schedule, but not the price values, may be changed by the Scheduling Coordinator in its Revised Day-Ahead Schedule, if any. These Adjustment Bids will not be transformed into Supplemental Energy bids.~~

~~30.3.2 Seven-Day Advance Schedules.~~

~~Scheduling Coordinators may submit Balanced Schedules for up to seven (7) Trading Days at a time, representing the Scheduling Coordinator's Preferred Schedule for each Day-Ahead Market and/or Hour-Ahead Market. These advance Schedules can be overwritten by new Preferred Schedules at any time prior to the deadline for submitting Day-Ahead Schedules and Hour-Ahead Schedules, as described in the SP. If not overwritten by the Scheduling Coordinator, a Schedule submitted in advance of this deadline for submission will become the Scheduling Coordinator's Preferred Schedule at the deadline for submitting Day-Ahead Schedules and/or Hour-Ahead Schedules. There is no validation of Schedules submitted in advance of the deadline for submitting Preferred Schedules.~~

~~30.3.3 Suggested Adjusted Schedules.~~

~~In the Day-Ahead scheduling process, if the sum of Scheduling Coordinators' Preferred Schedules would cause Congestion across any Inter-Zonal Interface, the ISO shall issue to all Scheduling Coordinators an estimate of the Usage Charges if Congestion is not relieved and Suggested Adjusted Schedules that shall~~

~~reflect adjustments made by the ISO to each Scheduling Coordinator's Preferred Schedule to eliminate Congestion, based on the initial Adjustment Bids submitted in the Preferred Schedules. The ISO will include in the Suggested Adjusted Schedules the resolution of any mismatches in Inter-Scheduling Coordinator Energy Trades, as determined by the ISO. These Suggested Adjusted Schedules will not apply to uses of transmission owned by Non-Participating TOs nor to uses of Existing Rights. A modification flag, set by the ISO, will indicate whether the scheduled output in a Settlement Period has been modified as a result of Congestion Management.~~

~~30.3.4 Revised Schedules.~~

~~Following receipt of a Suggested Adjusted Schedule, a Scheduling Coordinator may submit to the ISO a Revised Schedule, which shall be a Balanced Schedule, and which shall seek to reduce or eliminate Congestion. There are no Revised Schedules in the Hour-Ahead Market.~~

~~30.3.4.1 Final Schedules.~~

~~If the ISO notifies a Scheduling Coordinator that there will be no Congestion on the ISO Controlled Grid based on the Preferred Schedules submitted by all Scheduling Coordinators, then subject to Section 30.2.3.4, the Preferred Schedule shall become that Scheduling Coordinator's Final Schedule. If the ISO has issued Suggested Adjusted Schedules and if no Scheduling Coordinator submits any changes to the Suggested Adjusted Schedules, all of the Suggested Adjusted Schedules shall become the Final Schedules. If the ISO has adjusted the Scheduling Coordinator's Preferred Schedule to match Inter-Scheduling Coordinator Energy Trades then the adjusted Preferred Schedule shall become that Scheduling Coordinator's Final Schedule.~~

~~If the ISO notifies a Scheduling Coordinator that there will be no Congestion on the ISO Controlled Grid based on the Revised Schedules submitted by all Scheduling Coordinators, the Revised Schedule shall become that Scheduling Coordinator's Final Schedule. If the ISO has adjusted the Scheduling Coordinator's Revised Schedule to match Inter-Scheduling Coordinator Energy Trades then the adjusted Revised Schedule shall become that Scheduling Coordinator's Final Schedule. If there is Congestion based on the Revised Schedules or mismatches in Inter-Scheduling Coordinator Energy Trades, the ISO shall adjust the Revised Schedules and issue Final Schedules. The Scheduling Coordinators will be notified, via WEnet, that their Schedules have become final. The ISO will also publish a final set of Usage~~

~~Charges for Energy transfers between Zones, applicable to all Scheduling Coordinators. The Final Schedules shall serve as the basis for Settlement between the ISO and each Scheduling Coordinator.~~

~~30.3.4.2 Scheduling and Real-Time Information.~~

~~30.3.4.3 Final Schedules.~~

~~The scheduling process described in Section 30.3 will produce for the ISO real-time dispatchers for each Settlement Period of the Trading Day a Final Schedule consisting of the combined commitments contained in the Final Day-Ahead Schedules and the Final Hour-Ahead Schedules for the relevant Settlement Period.~~

~~**30.3.4.4** The Final Schedule will include information with respect to:~~

~~(a) Generation schedules;~~

~~(b) Demand schedules;~~

~~(c) Ancillary Services schedules based on the ISO's Ancillary Services auction;~~

~~(d) Ancillary Services schedules, based on Scheduling Coordinators ISO accepted schedules and forecast load, for self-provided Ancillary Services;~~

~~(e) Interconnection schedules between the ISO Control Area and other Control Areas; and~~

~~(f) Inter-Scheduling Coordinator Energy Trades.~~

~~30.3.5 Prohibition on Scheduling Across Out-of-Service Transmission Paths.~~

~~Scheduling Coordinators shall not submit any Schedule using a transmission path for any Settlement Period for which the Operating Transfer Capability for that path is zero MW. The ISO shall reject Schedules submitted for transmission paths on which the Operating Transfer Capability is zero MW. If the Operating Transfer Capability of a transmission path is reduced to zero after Final Day-Ahead Schedules have been submitted, then, if time permits, the ISO shall direct the responsible Scheduling Coordinators to reduce all Schedules on such zero-rated transmission paths to zero in the Hour-Ahead Market. As necessary to comply with Applicable Reliability Criteria, the ISO shall reduce any non-zero Final Hour-Ahead Schedules across zero-rated transmission paths to zero after the close of the Hour-Ahead Market. No Usage Charges will be assessed, nor will any Usage Charges for counter-flow be paid, for Schedules across a path with an Operating Transfer Capability of zero.~~

~~**30.3.5A No Scheduling Coordinator shall submit a Circular Schedule.** The ISO may~~

~~periodically provide examples of such Circular Schedules under the ISO Home Page.~~

~~30.4 Verification of Information.~~

~~The ISO 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 hereof and the accuracy of information submitted to the ISO pursuant to Section 30.2.~~

<u>30.4 Election for Start-Up and Minimum Load Costs.</u>

<u>Generating Units, Non-Dynamic and Dynamic System Resources may elect on a semi-annual basis either of the two options for specifying their Start-Up and Minimum Load Costs to be used in the CAISO Markets Processes:</u>

<u>(1) Cost-based. This option uses fuel-cost adjusted formulas for Start-Up and Minimum Load Costs based on the resource's actual performance parameters. The Start-Up and Minimum Load Costs values contained in the resource's Bids as utilized in the CAISO Markets Processes will be these formulaic values adjusted for fuel-cost variation on a daily basis. Resources will not be able to Bid alternative values for Start-Up and Minimum Load Costs.</u>

<u>(2) Bid-based. The resource may submit values of its choosing for Start-Up and Minimum Load Costs without regard to the resource's performance parameters or underlying costs. The SU and ML cost values contained in the resource's Bids as utilized in the CAISO Markets Processes will be these pre-specified values and will be fixed for six months. Resources will not be able to Bid alternative values for Start-Up and Minimum Load Costs.</u>

~~30.4.1 Validation of Balanced Schedules.~~

~~Each Scheduling Coordinator will be assigned a workspace within the ISO's scheduling system. Each workspace will have a work area for Day-Ahead and Hour-Ahead Schedules, Adjustment Bids and Supplemental Energy bids. The Scheduling Coordinator shall only be allowed to access and manipulate its Schedule and bid data within this workspace. Each area is organized into segments. A segment is used to hold the Scheduling Coordinator's Schedules relating to the same Trading Day. The Schedule validation process is divided into two stages. The ISO shall carry out the first stage validation immediately after it has received a Schedule. The ISO shall carry out the second stage validation ten (10) minutes before (pre-validation) and immediately after each deadline (as specified in the Scheduling~~

~~Protocol) for submission of Schedules. However, a Scheduling Coordinator can also initiate the stage two validation at any time prior to that deadline, as described in more detail in the Scheduling Protocol. If the Scheduling Coordinator adds a new Schedule or modifies an existing Schedule, that Schedule must be re-validated. Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Balanced Schedules.~~

~~**30.4.1.1 Stage One Validation.**~~

~~During stage one validation, each incoming Schedule will be validated to verify proper content, format and syntax. The ISO will check that the Scheduling Coordinator had not exceeded its Security Amount and verify that the Scheduling Coordinator is certified in accordance with the ISO Tariff. The ISO will further verify that the Scheduling Coordinator has inputted valid Generating Unit and Demand location identification. Scheduled Reliability Must-Run Generation will be verified against the contract reference numbers in the ISO's Scheduling Coordinator database. A technical validation will be performed verifying that a scheduled Generating Unit's output is not beyond it's declared capacity and/or operating limits. If there is an error found during stage one validation, the Scheduling Coordinator will be notified immediately through WEnet. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit the Schedule if it is still within the ISO's timing requirements. Additionally, if the ISO detects an invalid contract usage (of either Existing Contract rights or Firm Transmission Rights), the ISO will issue an error message in similar manner to the Scheduling Coordinator and allow the Scheduling Coordinator to view the message(s), to make changes, and to resubmit the contract usage template(s) if it is still within the ISO's timing requirements. The Scheduling Coordinator is also notified of successful validation via WEnet.~~

~~**30.4.1.2 Stage Two Validation.**~~

~~During stage two validation, Schedules will be checked to determine whether each Scheduling Coordinator's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) equals the Scheduling Coordinator's aggregate Demand Forecast, including external exports. The Scheduling Coordinator must take into account the applicable Generation Meter Multipliers (GMMs). The Scheduling Coordinator will be notified if the counterpart trade to any Inter-Scheduling Coordinator Ancillary Service Trade has not~~

~~been submitted, or is infeasible (i.e., if both Scheduling Coordinators are selling or both are buying). Mismatches in Inter-Scheduling Coordinator Ancillary Service Trades shall be adjusted to be equal to the amount specified by the selling Scheduling Coordinator. A Scheduling Coordinator can also check whether its Schedules will pass the ISO's stage two validation by manually initiating validation of its Preferred Schedules or Revised Schedules, at any time prior to the deadline for submission of Preferred Schedules or Revised Schedules (as the case may be). It is the Scheduling Coordinator's responsibility to perform such checks, if desired. The Scheduling Coordinator will be notified immediately through WEnet of any validation errors. For each error detected, an error message will be generated by the ISO in the Scheduling Coordinator's notification screen which will specify the nature of the error. If the ISO detects a mismatch in Inter-Scheduling Coordinator Trades, the ISO will notify both Scheduling Coordinators of the mismatch in Energy quantity and/or location. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit the Schedule if it is still within the ISO's timing requirements. The Scheduling Coordinator is also notified of successful validation via WEnet.~~

~~30.4.5 Validation of Energy Bids.~~

~~The ISO will check whether Energy Bids comply with the format requirements and will notify a Scheduling Coordinator if its bid does not so comply. A Scheduling Coordinator can check whether its Energy Bids will pass the ISO's validation by manually initiating validation of its Energy Bids at any time prior to the deadline for submission of Energy Bids. It is the Scheduling Coordinator's responsibility to perform such checks. Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Energy Bids.~~

~~30.4.2 Validation of Existing Contract Schedules.~~

~~Each Schedule submitted to the ISO by a Scheduling Coordinator representing a rights holder to an Existing Contract must include a valid contract reference number in accordance with Section 16.2.4A.1. If the Schedule includes an Inter-Scheduling Coordinator Trade, only one of the Scheduling Coordinators should submit a contract reference number. If a match of the Schedule's contract reference number is found in the ISO's database and the Schedule is consistent with the instructions submitted previously by~~

~~the Responsible PTO, the Schedule will be implemented in accordance with the instructions. If a match of the Schedule's contract reference number cannot be found in the ISO's database or if both Scheduling Coordinators which are parties to an Inter-Scheduling Coordinator Trade submit contract reference numbers, the ISO will issue an error message to the Scheduling Coordinator via the WEnet (as described in Section 30.4.1.1) and indicate the nature of the problem. The ISO will assist the Scheduling Coordinator, within reason, in resolving the problem so that the Scheduling Coordinator is able to submit the Schedule successfully as soon as possible within the ISO's timing requirements of the SP. If the Scheduling Coordinator uses a contract reference number for which the responsible PTO has not reserved transmission capacity on a particular path (i.e., the contract reference Number(s) included on a contract usage template cannot be found in the ISO's scheduling applications table of contract reference numbers), the Scheduled use will be invalidated and the Scheduling Coordinator notified by the ISO's issuance of an invalidated usage information template.~~

~~30.4.3 Validation of Adjustment Bids.~~

~~30.4.3.1 Invalidation.~~

~~The absence of an Adjustment Bid in a Scheduling Coordinator's Preferred Schedule or Revised Schedule will not affect the validation since Scheduling Coordinators are not required to submit Adjustment Bids. If an Adjustment Bid is contained in the Scheduling Coordinator's Preferred Schedule or Revised Schedule but is not in the form described above, both the Schedule and the Adjustment Bid will be rejected. The Scheduling Coordinator will be notified immediately, via WEnet, of any validation errors. For each error detected, an error message will be generated by the ISO 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 timing requirements of the SP. The Scheduling Coordinator is also notified of successful validation via WEnet. The Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Adjustment Bids.~~

~~30.4.3.2 Validation Checks.~~

~~The ISO's stage one validation checks are performed automatically, whenever Schedules and Adjustment Bids are submitted. The ISO's stage two validation is performed automatically. A Scheduling~~

~~Coordinator can also check whether its Adjustment Bids will pass the ISO's stage two validation by manually initiating validation of its Preferred Schedule or Revised Schedule, at any time prior to the deadline for submission of Preferred Schedules or Revised Schedules. It is a Scheduling Coordinator's responsibility to perform such checks.~~

~~30.4.4 Validation of Ancillary Services Bids.~~

~~The ISO will verify that each Ancillary Services Schedule or bid conforms to the format specified for the relevant service. If the Ancillary Services Schedule or bid does not so conform, the ISO will send a notification to the Scheduling Coordinator notifying the Scheduling Coordinator of the errors in the Schedules and/or bids. Scheduling Coordinators will comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Ancillary Services Schedules and bids. Shown below are the two stages of validation carried out by the ISO:~~

~~30.4.4.1 Stage One Validation.~~

~~During stage one validation, each incoming Ancillary Services schedule or bid will be validated to verify proper content, format and syntax. A technical validation will be performed to verify that a schedule or bid quantity of Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve does not exceed the available capacity for Regulation, Operating Reserves and Replacement Reserve on the Generating Units, System Units, Curtailable Demands and external imports/exports scheduled or bid. The Scheduling Coordinator will be notified immediately through WEnet of any validation errors. For each error detected, an error message will be generated by the ISO 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 ISO's timing requirements. The Scheduling Coordinator is also notified of successful validation via WEnet.~~

~~30.4.4.2 Stage Two Validation.~~

~~Stage two validation will be conducted by the ISO in accordance with Appendix E of the ISO Tariff.~~

~~30.4.4.3 Validation Checks.~~

~~The ISO's stage one validation checks are performed automatically whenever Ancillary Services Schedules and bids are submitted. The ISO's stage two validation is performed automatically. A~~

~~Scheduling Coordinator can also check whether its Ancillary Services Schedules and bids will pass the ISO's stage two validation by manually initiating validation of its Ancillary Services Schedules and bids, as described in the SP, at any time prior to the deadline for submission of Ancillary Services Schedules and bids. It is a Scheduling Coordinator's responsibility to perform such checks.~~

~~30.4.6 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 nine segments defined by a set of 1 to 10 pairs, e.g., (50,1),(100,3),(200,2), (300,2). There is no monotonicity requirement for the operational ramp rate. The submitted operational ramp rate shall be validated as follows:~~

- ~~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.~~
- ~~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.~~
- ~~If a Scheduling Coordinator does not submit an operational ramp rate for a generating unit for a day, the ISO 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 that day.~~
- ~~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.~~
- ~~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 hour must be the same with the one(s) submitted earlier for previous hours in the same Trading Day.~~
- ~~Outages that affect the submitted operational ramp rate must be due to physical constraints, reported in SLIC and are subject to ISO 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.~~

- ~~For all ISO Dispatch Instructions of Reliability Must Run resources the operational ramp rate will be the ramp rate declared in the Reliability Must Run Contract Schedule A.~~

~~30.4.7 Format and Validation of Startup and Shutdown Times.~~

~~For a Generating Unit, the submitted startup time expressed in minutes (min) as a function of down time expressed in minutes (min) must be a staircase function with up to 10 segments defined by a set of 1 to 10 down time and startup time pairs. The startup time is the time required to start the resource if it is offline longer than the corresponding down time. The last segment will represent the time to start the unit from a cold start and will extend to infinity. The submitted startup time function shall be validated as follows:~~

- ~~The first down time must be 0 min.~~
- ~~The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the maximum startup time function, as registered in the Master File for the relevant resource.~~
- ~~The startup time for each segment must not exceed the startup time of the corresponding segment of the maximum startup time function, as registered in the Master File for the relevant resource.~~
- ~~The startup time function must be strictly monotonically increasing, i.e., the startup time must increase as down time increases.~~

~~For Curtailable Demand, a single shutdown time in minutes is the time required for the resource to shut down after receiving a Dispatch Instruction.~~

~~30.4.8 Format and Validation of Startup and Shutdown Costs.~~

~~For a Generating Unit, the submitted startup cost expressed in dollars ($) as a function of down time expressed in minutes (min) must be a staircase function with up to 10 segments defined by a set of 1 to 10 down time and startup cost pairs. The startup cost is the cost incurred to start the resource if it is offline longer than the corresponding down time. The last segment will represent the cost to start the resource from cold startup and will extend to infinity. The submitted startup cost function shall be validated as follows:~~

~~• The first down time must be 0 min.~~

~~• The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the cost-based startup cost function, as registered in the Master File for the relevant resource.~~

~~• The startup cost for each segment must not be negative and must not exceed the startup cost of the corresponding segment of the cost-based startup cost function, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based startup cost function shall be derived from the startup fuel function, as registered in the Master File for the relevant resource, and the applicable gas price index as approved by FERC.~~

~~• The startup cost function must be strictly monotonically increasing, i.e., the startup cost must increase as down time increases.~~

~~For Curtailable Demand, a single shutdown cost in $ is the cost incurred to shut down the resource after receiving a Dispatch Instruction. The submitted shutdown cost must not be negative.~~

~~**30.4.9 Format and Validation of Minimum Load Costs.**~~

~~For a Generating Unit, the submitted Minimum Load Cost expressed in dollars per hour ($/hr) is the cost incurred for operating the unit at minimum load. The submitted Minimum Load Cost must not be negative and must not exceed the cost-based Minimum Load Cost, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based Minimum Load Cost shall be derived pursuant to Section 40.1.6.1.2.~~

~~For Curtailable Demand, the submitted Minimum Load Cost ($/hr) is the cost incurred while operating the resource at reduced consumption after receiving a Dispatch Instruction. The submitted Minimum Load Cost must not be negative.~~

~~**30.5 [Not Used]**~~

30.5 Bidding Rules

30.5.1 General Bidding Rules

(a) All Energy and Ancillary Services Bids of each Scheduling Coordinator 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 7 days prior to the Trading Day;

(b) Bid prices submitted by Scheduling Coordinator for Energy accepted and cleared in the IFM and scheduled in the Day-Ahead Schedule cannot be decreased. Bid prices for Energy submitted but not scheduled in the Day-Ahead Schedule may be increased or decreased in the HASP. Incremental Bid prices for Energy associated with Day-Ahead AS or RUC Awards in Bids submitted to the HASP may be revised. Scheduling Coordinators may revise ETC 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 PTO in accordance with Section 16 of this CAISO Tariff;

(c) Scheduling Coordinators may submit Energy, AS and RUC Bids in the DAM that are different for each Trading Hour of the Trading Day;

(d) 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; and

(e) ~~**30.4 Verification of Information.**~~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 hereof and the accuracy of information submitted to the CAISO pursuant to this Section 30.

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 ID; Resource Location; PNode or Aggregated Pricing Node as applicable; Energy Bid Curve; Self-Schedule component; Ancillary Services Bid; RUC Availability Bid; the Market to which the Bid applies; Trading Day to which the Bid applies; Priority Type (if any).

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: Start-Up Bid, Minimum Load Bid, Ramp Rate, minimum and maximum Operating limits; Distribution Curve; Must-Take/Must-Run Generation; Contingency Flag; and Contract Reference Number (if any). Combined-cycle Generation Units may only be registered under a single Resource ID.

30.5.2.3 Supply Bids for Participating Loads

In addition to the common elements listed in Section 30.5.2.1, Scheduling Coordinators submitting Supply Bids for Participating Loads shall contain the following components: Pumping and Participating Load, Minimum Load Bid, Load Distribution Curve, Ramp Rate, Energy Limit, Demand Reduction Initiation, and Participating Load and Pump Shut-Down Costs for resources registered as Pumped Storage Hydro Units.

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 System Resources shall also contain: a NERC Tag; the relevant Ramp Rate; Start-Up Bid; and Minimum Load Bid. Start-Up Bids and Minimum Load Bids for System Resources, except for Dynamic or Non-Dynamic System Resources must be zero. Dynamic or Non-Dynamic Resource-Specific System Resources may submit non-zero Start-Up and Minimum Loads Bids. ~~**30.2.5 For Interruptible Imports:**~~The quantity (in MWh) of Energy categorized as Interruptible Imports ~~and whether the Scheduling Coordinator intends to self-provide the Operating Reserve required by Section 8.2.3.2 to cover such Interruptible Imports or to purchase such Operating Reserve from the ISO~~must also be included in the Bid~~.~~

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 for Energy and Ancillary Services, 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. Scheduling Coordinators that represent MSS Operators that have opted out of RUC participation pursuant to Section 31.5 must Self-Schedule one hundred (100) percent of the Demand Forecast for the MSS. 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 4.9.9, 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 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 HASP.

30.5.2.6 Ancillary Services Bids.

———There are four distinct Ancillary Services: Regulation-Up, Regulation-Down, Spinning Reserve and Non-Spinning Reserve. Participating Generators are eligible to provide all Ancillary Services. Dynamic System Resources are eligible to provide Operating Reserves and Regulation. Non-Dynamic System Resources are eligible to provide Operating Reserves only. Participating Loads are eligible to provide Non-Spinning Reserve only. A Scheduling Coordinator may submit Ancillary Services Bids for Regulation-Up, Regulation-Down, Spinning, 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. 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) an Energy Bid associated with capacity Bid; (3) Ramp Rate (Operating Reserve Ramp Rate and regulating ramp rate, if applicable); (4) Distribution Curve for Physical Scheduling Plant or System Unit; and (5) maximum operating level (MOL_{max}) and minimum operating level (MOL_{min}). A Submission to Self Provide an Ancillary Service shall contain all of the requirements of a Bid for Ancillary Services with the exception of price information. In addition, Scheduling Coordinators must comply with the Ancillary Services requirements of Section 8.5 of the CAISO Tariff.

30.5.2.6.1 Regulation Up or Down Bid Information.

In the case of Regulation Up or Down, the Ancillary Services Bid must also contain: (a) the upward and downward range of generating capacity over which the resource is willing to provide Regulation within a range from a minimum of 10 minutes to a maximum of 30 minutes; and (b) the bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($/MW). In the case of Regulation Up or Down from Dynamic System Resources, the Ancillary Services Bid must also contain: (a) the Scheduling Point (the name), (b) Interchange ID code of the selling entity, (c) external Control Area ID, (d) Schedule ID (NERC ID number) and complete NERC tag, and (e) the Contract Reference Number, if applicable.

30.5.2.6.2 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 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) Interchange ID code of the selling entity, (b) Schedule ID (NERC ID number) and complete NERC tag, and (c) a Contract Reference Number, if applicable.

30.5.2.6.3 Non-Spinning Reserve Capacity.

In the case of Non-Spinning Reserve, the Ancillary Service Bid must also contain: (a) the MW capability available within 10 minutes; (b) the Bid price of the capacity reservation; (c) time of synchronization following notification (min); 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) Interchange ID code of the selling entity, (b) Schedule ID (NERC ID number) and complete NERC tag; and (c) a Contract Reference Number, if applicable. In the case of Non-Spinning Reserve Capacity from Load within the CAISO Control Area, the Ancillary Service Bid must also contain: (a) a Load identification name and

Location Code, (b) Demand reduction available within 10 minutes, (c) time to interruption following notification (min), and (d) maximum allowable curtailment duration (hr).

30.5.2.6.4 ~~30.2.4~~ For Self-Provided Ancillary Services:

Scheduling Coordinators electing to self-provide Ancillary Services shall supply the information referred to in this Section 30.5 ~~8.6.4.2A~~ 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. ~~**34.1.2.2** Real-Time Energy Bid Partition.~~ The portion of the single 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~~and (d) Replacement 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 ~~Supplemental~~ Energy.

30.5.2.7 RUC Availability Bids

Scheduling Coordinators may submit RUC Availability Bids for specific Generating Units in the DAM. Capacity that does not have Bids for Supply of Energy in the IFM will not be eligible to participate in the RUC process. The RUC Availability Bid component a is MW-quantity of non-RA Capacity in $/MW per hour, and $0/MW for RA Capacity.

30.5.3 Demand Bids

Each Scheduling Coordinator representing Demand 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. Scheduling Coordinators must submit must submit a zero RUC Availability Bid for the portion of their qualified RA Capacity.

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 10 segments defined by 11 ordered pairs of MW and $/MWh; Location Code for the 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 for Submission of Demand Bids at the LAP

Scheduling Coordinators shall not submit Demand Bids and the CAISO shall not settle such Bids at the LAP in the following circumstances:

(a) ETC or TOR Self-Schedules consistent with the submitted TRTC Instructions;

(b) Demand Bids for Participating Loads; and

(c) Export Bids at Scheduling Points.

30.6 ~~RMR~~[NOT USED].

~~**30.6.1 Procurement of Reliability Must-Run Generation by the ISO.**~~

~~**30.6A.1** A Reliability Must-Run Contract is a contract entered into by the ISO with a Generator which operates a Generating Unit giving the ISO the right to call on the Generator to generate Energy and, only as provided in this Section 30.6.1, or as needed for Black Start or Voltage Support required to meet local reliability needs, or to procure Ancillary Services from Potrero or Hunter's Point power plants to meet operating criteria associated with the San Francisco local reliability area, to provide Ancillary Services from the Generating Units as and when this is required to ensure that the reliability of the ISO Controlled Grid is maintained.~~

~~**30.6A.1.1** If the ISO, pursuant to Section 8.5.4(e), has elected to procure an amount of megawatts of its forecast needs for an Ancillary Service in the Hour-Ahead Markets and there is not an adequate amount of capacity bid into an Hour-Ahead Market for the ISO to procure such amount of megawatts of that Ancillary Service (excluding bids that exceed price caps imposed by the ISO or FERC), the ISO may call upon Reliability Must-Run Units under Must-Run Contracts to meet the remaining portion of that amount of megawatts for that Ancillary Service but only after accepting all available bids in the Hour-Ahead Market (including any unused bids that can be used to satisfy that particular Ancillary~~

~~Services requirement under Section 8.2.3.6), except that the ISO shall not be required to accept bids that exceed price caps imposed by the ISO or the FERC.~~

~~**30.6A.1.2** If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day –~~

~~(1) the ISO determines that it requires more of an Ancillary Service than it has procured;~~

~~(2) all additional Day-Ahead bids for that Ancillary Service that have not been withdrawn (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 8.2.3.6) have been selected pursuant to Section 8.7, except that the ISO shall not be required to accept bids that exceed price caps imposed by the ISO or the FERC;~~

~~(3) the ISO has notified Scheduling Coordinators of the circumstances existing in paragraphs (1) and (2) of this Section 30.6A.1.2; and~~

~~(4) after such notice, the ISO determines that a Bid Insufficiency condition exists in the Hour-Ahead Market for the Settlement Period in which the ISO requires more of an Ancillary Service;~~

~~the ISO may call upon Reliability Must-Run Units under Reliability Must-Run Contracts to meet the additional needs in addition to any amounts that the ISO has called upon under Section 30.6A.1.1. The ISO must provide the notice specified in paragraph (3) of this Section 30.6A.1.2 as soon as possible after the ISO determines that additional Ancillary Services are needed for which bids are not available. The ISO may only determine that a Bid Insufficiency exists in the Hour-Ahead Market after the close of the Hour-Ahead Market, unless an earlier determination is required in order to accommodate the Reliability Must-Run Unit's operating constraints. For the purposes of this Section, a Bid Insufficiency exists in an Hour-Ahead Market if, and only if –~~

~~(a) bids in the Hour-Ahead Market for the particular Ancillary Service (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 8.2.3.6) that remain after first procuring the megawatts of the Ancillary Service that the ISO had notified Scheduling Coordinators it would procure in the Hour-Ahead Market pursuant to Section 8.5.4 ("remaining Ancillary Service requirement") represent, in the aggregate, less than two times such remaining Ancillary Service requirement; or~~

~~(b) there are less than two unaffiliated bidders to provide such remaining Ancillary Service requirement.~~

~~If a Bid Insufficiency condition exists, the ISO may nonetheless accept available market bids if it determines in its sole discretion that the prices bid and the supply curve created by the bids indicate that the bidders were not attempting to exercise market power.~~

~~**30.6A.2** The ISO will, subject to any existing power purchase contracts of a Generating Unit, have the right at any time based upon ISO Controlled Grid technical analyses and studies to designate a Generating Unit as a Reliability Must-Run Unit. A Generating Unit so designated shall then be obligated to provide the ISO with its proposed rates for Reliability Must-Run Generation for negotiation with the ISO. Such rates shall be authorized by FERC or the Local Regulatory Authority, whichever authority is applicable.~~

~~**30.6A.3** On a yearly basis, the ISO will carry out technical evaluations based upon historic patterns of the operation of the ISO Controlled Grid and the ISO's forecast requirements for maintaining the reliability of the ISO Controlled Grid in the next year. The ISO will then determine which Generating Units it requires to continue to be Reliability Must-Run Units, which Generating Units it no longer requires to be Reliability Must-Run Units and which Generating Units it requires to become the subject of a Reliability Must-Run Contract which had not previously been so contracted to the ISO. None of the Generating Units owned by Local Publicly Owned Electric Utilities are planned to be designated as Reliability Must-Run Units by the ISO as of the ISO Operations Date but are expected to be operated in such a way as to maintain the safe and reliable operation of the interconnected transmission system comprising the ISO Control Area. However, in the future, Local Publicly Owned Electric Utilities may contract with the ISO to provide Reliability Must-Run Generation.~~

~~**30.6A.4** A *pro forma* of the Reliability Must-Run Contract is attached as Appendix G. From the ISO Operations Date all Reliability Must-Run Units will be placed under the "As Called" conditions, but the parties may, pursuant only to the terms of the Reliability Must-Run Contract, Transfer any such unit to one of the alternative forms of conditions under specific circumstances. The ISO will review the terms of the applicable forms of agreement applying to each Reliability Must-Run Unit to ensure that the ISO will procure Reliability Must-Run Generation from the cheapest available sources and to maintain System~~

~~Reliability. The ISO shall give notice to terminate Reliability Must-Run Contracts that are no longer necessary or can be replaced by less expensive and/or more competitive sources for maintaining the reliability of the ISO Controlled Grid.~~

~~**30.6.1.1 Reliability Must-Run Charge.**~~

~~The ISO shall prepare and send to each Responsible Utility in accordance with Appendix N, Part J an ISO Invoice in respect to those costs incurred under each Reliability Must-Run Contract that are payable to the ISO by such Responsible Utility or payable by the ISO to such Responsible Utility pursuant to Section 30.6.1.2. The ISO Invoices shall reflect all reductions or credits required or allowed under or arising from the Reliability Must-Run Contract or under this Section 30.6.1.1. The ISO Invoice shall separately show the amounts due for services from each RMR Owner. Each Responsible Utility shall pay the amount due under each ISO Invoice by the due date specified in the ISO Invoice, in default of which interest shall become payable at the interest rate provided in the Reliability Must-Run Contract from the due date until the date on which the amount is paid in full. For each Reliability Must-Run Contract, the ISO shall establish two, segregated commercial bank accounts under the "Facility Trust Account" referred to in Appendix N, Part J and Article 9 of the Reliability Must-Run Contract. One commercial bank account, the "RMR Owner Facility Trust Account," shall be held in trust by the ISO for the RMR Owner. The other commercial bank account, the "Responsible Utility Facility Trust Account," shall be held in trust by the ISO for the Responsible Utility. Payments received by the ISO from the Responsible Utility in connection with the Reliability Must-Run Contract, including payments following termination of the Reliability Must-Run Contract, will be deposited into the RMR Owner Facility Trust Account and payments from the ISO to the RMR Owner will be withdrawn from such account, in accordance with Section 30.6.1.1, Article 9 of the Reliability Must-Run Contract and Appendix N, Part J. Any payments received by the ISO from the RMR Owner in connection with the Reliability Must-Run Contract will be deposited into the Responsible Utility Facility Trust Account. Any payments due to the Responsible Utility of funds received from the RMR Owner in connection with the Reliability Must-Run Contract will be withdrawn from the Responsible Utility Facility Trust Account, in accordance with this Section 30.6.1.1, Appendix N, Part J and Article 9 of the Reliability Must-run Contract. Neither the RMR Owner Facility Trust Account nor the Responsible Utility Trust Account shall have other funds commingled in it at any time. The ISO shall not~~

~~modify this Section 30.6.1.1 or Appendix N, Part J as it applies to procedures for the billing, invoicing and payment of charges under Reliability Must-Run Contracts without the Responsible Utility's consent, provided, however, that no such consent shall be required with respect to any change in the method by which costs incurred by the ISO under RMR Contracts are allocated to or among Responsible Utilities.~~

~~**30.6.1.1.1** Except where the Responsible Utility is also the RMR Owner, the Responsible Utility's payment of the ISO Invoice shall be made without offset, recoupment or deduction of any kind whatsoever. Notwithstanding the foregoing, if the ISO fails to deduct an amount required to be deducted under Section 30.6.1.1.1.1, the Responsible Utility may deduct such amount from payment otherwise due under such ISO Invoice.~~

~~**30.6.1.1.1.1** If the Responsible Utility disputes an ISO Invoice, Revised Estimated RMR Invoice, or Revised Adjusted RMR Invoice, or Final Invoice, it shall pay the ISO Invoice but may pay under protest and reserve its right to seek a refund, with interest, from the ISO. If resolution of the dispute results in an amount paid by the Responsible Utility under protest being due from the ISO to the Responsible Utility and from the RMR Owner to the ISO, and such amount was paid to the RMR Owner by the ISO, then such amount, with interest at the interest rate specified in the applicable Reliability Must-Run Contract from the date of payment until the date on which the amount is repaid in full, shall be refunded by the RMR Owner to the ISO and from the ISO to the Responsible Utility, pursuant to Article 9 of the Reliability Must-Run Contract and Appendix N, Part J, by the RMR Owner's inclusion of such refund amount in the appropriate invoice. If the RMR Owner does not include such refund amount (including interest) in the appropriate invoice, then such refund amount shall be deducted by the ISO from the next succeeding amounts otherwise due from the Responsible Utility to the ISO and from the next succeeding amounts otherwise due from the ISO to the RMR Owner with respect to the applicable Reliability Must-Run Contract or, if such Contract has terminated, such amount shall be refunded by the ISO to the Responsible Utility; provided, however, that if and to the extent that such resolution is based on an error or breach or default of the RMR Owner's obligations to the ISO under the Reliability Must-Run Contract, then such refund obligation shall extend only to amounts actually collected by the ISO from the RMR Owner as a result of such resolution. If resolution of the dispute requires the ISO, but not the RMR Owner, to pay the Responsible Utility, then such award shall be recovered from any applicable insurance~~

~~proceeds, provided that to the extent sufficient funds are not recoverable through insurance, the amount of the award (whether determined through settlement, or ADR or otherwise) shall be collected by the ISO pursuant to Section 13.5, and in any event, the award shall be paid by the ISO to the Responsible Utility pursuant to Section 13.5.~~

~~**30.6.1.1.1.2** If the Responsible Utility disputes an ISO Invoice, a Revised Estimated Invoice, a Revised Adjusted RMR Invoice, or a Final Invoice, or part thereof, based in whole or in part on an alleged error by the RMR Owner or breach or default of the RMR Owner's obligations to the ISO under the Reliability Must-Run Contract, the Responsible Utility shall notify the ISO of such dispute within 12 months of its receipt of the applicable Revised Adjusted RMR Invoice or Final Invoice from the ISO, except that the Responsible Utility may also dispute a Revised Estimated RMR Invoice, Revised Adjusted RMR Invoice, or Final Invoice for the reasons set forth above in this Section 30.6.1.1.1.2, within 60 days from the issuance of a final report with respect to an audit of the RMR Owner's books and accounts allowed by a Reliability Must-Run Contract.~~

~~30.6.1.1.1.3 If the Responsible Utility disputes an ISO Invoice, a Revised Estimated RMR Invoice, a Revised Adjusted RMR Invoice, or a Final Invoice, based in whole or in part on an alleged error by the ISO or breach or default of the ISO's obligations to the Responsible Utility, the Responsible Utility shall notify the ISO of such dispute prior to the later to occur of (i) the date 12 months following the date on which the ISO submitted such invoice to the Responsible Utility for payment or (ii) the date 60 days following the date on which a final report is issued in connection with an operational audit, pursuant to Section 22.1.2.2, of the ISO's performance of its obligations to Responsible Utilities under this Section 30.6.1.1 conducted by an independent third party selected by the ISO Governing Board and covering the period to which such alleged dispute relates. The ISO or any Responsible Utility shall have the right to request, but not to require, that the ISO Governing Board arrange for such an operational audit at any time.~~

~~**30.6.1.1.1.4** Notwithstanding Section 13 of this ISO Tariff, any Responsible Utility dispute relating to an ISO Invoice, a Revised Estimated Invoice, a Revised Adjusted Invoice, a Final Invoice, or a RMR Charge, RMR Payment or RMR Refund as defined in Appendix N, Part J, shall be resolved through the dispute resolution process specified in the relevant RMR Contract. If the Responsible Utility fails to notify~~

~~the ISO of any dispute as provided above, it shall be deemed to have validated the invoice and waived its right to dispute such invoice.~~

~~**30.6.1.1.2** The RMR Owner shall, to the extent set forth herein, be a third party beneficiary of, and have all rights that the ISO has under the ISO Tariff, at law, in equity or otherwise, to enforce the Responsible Utility's obligation to pay all sums invoiced to it in the ISO Invoices but not paid by the Responsible Utility, to the extent that, as a result of the Responsible Utility's failure to pay, the ISO does not Pay the RMR Owner on a timely basis amounts due under the Reliability Must-Run Contract. The RMR Owner's rights as a third party beneficiary shall be no greater than the ISO's rights and shall be subject to the dispute resolution process specified in the relevant RMR Contract. Either the ISO or the RMR Owner (but not both) will be entitled to enforce any claim arising from an unpaid ISO Invoice, and only one party will be a "disputing party" under the dispute resolution process specified in the relevant RMR Contract with respect to such claim so that the Responsible Utility will not be subject to duplicative claims or recoveries. The RMR Owner shall have the right to control the disposition of claims against the Responsible Utility for non-payments that result in payment defaults by the ISO under a Reliability Must-Run Contract. To that end, in the event of non-payment by the Responsible Utility of amounts due under the ISO Invoice, the ISO will not take any action to enforce its rights against the Responsible Utility unless the ISO is requested to do so by the RMR Owner. The ISO shall cooperate with the RMR Owner in a timely manner as necessary or appropriate to most fully effectuate the RMR Owner's rights related to such enforcement, including using its best efforts to enforce the Responsible Utility's payment obligations if, as, to the extent, and within the time frame, requested by the RMR Owner. The ISO shall intervene and participate where procedurally necessary to the assertion of a claim by the RMR Owner.~~

~~**30.6.1.1.3** If a Responsible Utility first executed a TCA after April 1, 1998 (a "New Responsible Utility") and if:~~

~~(i) the senior unsecured debt of the New Responsible Utility is rated or becomes rated at less than A- from Standard & Poor's ("S&P") or A3 from Moody's Investment Services ("Moody's"), and~~

~~(ii) Such ratings do not improve to A- or better from S&P or A3 or better from Moody's within 60 days,~~

~~the New Responsible Utility shall issue and confirm to the ISO an irrevocable and unconditional letter of credit in an amount equal to three times the highest monthly payment invoiced by the ISO to the New Responsible Utility (or the prior Responsible Utility) in connection with services under Reliability Must-Run Contracts in the last 3 months for which invoices have been issued. The letter of credit must be issued by a bank or other financial institution whose senior unsecured debt rating is not less than A from S&P and A2 from Moody's. The letter of credit shall be in such form as the ISO may reasonably require from time to time by notice to the New Responsible Utility and shall authorize the ISO or the Owner to draw on the letter of credit for deposit solely into the RMR Owner Facility Trust Account in an amount equal to any amount due and not paid by the Responsible Utility under the ISO Invoice. The security provided by the New Responsible Utility pursuant to this Section 30.6.1.1.3 is intended to cover the New Responsible Utility's outstanding liability for payments it is liable to make to the ISO under this Section 30.6.1.1, including monthly payments, any reimbursement for capital improvement, termination fees and any other payments to which the ISO is liable under Reliability Must-Run Contracts.~~

~~30.6.1.2 Responsibility for Reliability Must-Run Charge.~~

~~Except as otherwise provided in Section 30.6.1.2.1, the costs incurred by the ISO under each Reliability Must-Run Contract shall be payable to the ISO by the Responsible Utility in whose PTO Service Territory the Reliability Must-Run Generating Units covered by such Reliability Must-Run Contract are located or, where a Reliability Must-Run Generating Unit is located outside the PTO Service Territory of any Responsible Utility, by the Responsible Utility or Responsible Utilities whose PTO Service Territories are contiguous to the Service Area in which the Generating Unit is located, in proportion to the benefits that each such Responsible Utility receives, as determined by the ISO. Where costs incurred by the ISO under a Reliability Must-Run Contract are allocated among two or more Responsible Utilities pursuant to this section, the ISO will file the allocation under Section 205 of the Federal Power Act.~~

~~30.6.1.2.1 Responsibility for Reliability Must-Run Charges Associated with SONGS.~~

~~If the ISO procures Reliability Must-Run Generation from the San Onofre Nuclear Generation Station Units 2 or 3, it shall determine prior to the operation of such facilities as Reliability Must-Run Generation the appropriate allocation of associated charges, if any, among Responsible Utilities. The allocation of~~

~~such charges shall be based on the reliability benefits that the ISO reasonably identifies through studies and analysis as accruing to the respective Service Areas of the Responsible Utilities.~~

~~**30.6.1.2.2** The ISO may Dispatch an RMR Unit that has currently selected Condition 2 of its RMR Contract to provide Energy through an out-of-market transaction for reasons other than to manage Intra-Zonal Congestion or to address local reliability under the following conditions:~~

~~(1)The ISO projects that it will require Energy from the Condition 2 RMR Unit to (a) meet forecast Demand and operating reserve requirements or (b) manage Inter-Zonal Congestion;~~

~~(2)If ISO must Dispatch a Condition 2 RMR Unit to meet forecast Demand and operating reserve requirements, the ISO must first revoke or deny waivers of the must-offer obligation from all other Generating Units, including non-Condition 2 RMR Units and Generating Units not subject to an RMR Contract subject to the must-offer obligation and not on outage, except as set forth in item (5) below;~~

~~(3)If ISO must Dispatch a Condition 2 RMR Unit to manage projected Inter-Zonal Congestion, the ISO must first revoke or deny waivers of the must-offer obligation from all other Generating Units, including non-Condition 2 RMR Units and Generating Units not subject to an RMR Contract subject to the must-offer obligation, that are within the Congested Zone, except as set forth in item (5) below;~~

~~(4)Before Dispatching a Condition 2 RMR Unit in accordance with this Section 30.6.1.2.2, the ISO must notify Market Participants of (a) the situation for which the ISO is contemplating Dispatching a Condition 2 RMR Unit in accordance with this Section 30.6.1.2.2, and (b) the date and time the ISO requires the Condition 2 RMR Unit so Dispatched to be operating. The ISO shall provide such notice as far in advance as practical and prior to directing the Condition 2 Unit to start up;~~

~~**(5)**The ISO does not have to revoke or deny a waiver to a Generating Unit (a) subject to environmental limitations if doing so would violate such limitations, or cause the Generating Unit to be unavailable in the future, or if the environmental limitations currently restrict the availability or use of the Generating Unit; or (b) if that Generating Unit would cause or exacerbate Congestion, Overgeneration or other operational problem; or (c) if that Generating Unit is incapable of being available for Dispatch in the required timeframe.~~

~~Notwithstanding anything to the contrary in the applicable RMR Contract, all MWh, start-ups and service hours provided by a Generating Unit that has currently selected Condition 2 of its RMR Contract pursuant~~

~~to this Section 30.6.1.2.2 outside of the RMR Contract shall not be used to determine future RMR Contract Annual Service Limits. Payment for Dispatches pursuant to this Section 30.6.1.2.2 is governed by Section 11.2.4.2 of this Tariff.~~

~~30.6.1.3 Identification of Generating Units.~~

~~Each 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 ISO.~~

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 HASP, 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 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. All validation processes and default modifications are performed after Bids are submitted but prior to the Market Close for the relevant Trading Day or Trading Hour. Clean Bids will be generated after Market Close.

30.7.3 DAM 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 either 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. Some examples of when a Bid will be automatically modified and assigned a status of modified or conditionally modified Bids, include but are not limited to, extension of: (1) a Self-Schedule to the first Energy Bid point in cases where the total Self-Schedule quantity specified in a Bid is lower than the first Energy Bid quantity of the Energy Bid curve; or (2) an Energy Bid Curve range where the Energy Bid Curve submitted does not cover other commodities such as RUC or Ancillary Services for the same resource. Throughout the Bid evaluation process, the Scheduling Coordinator shall have the ability to view the Bid and may choose to either 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.

30.7.3.2 Master File Data Update.

Once a day the Master File data is updated with changes to the Master File that were submitted at least seven (7) 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 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 Scheduling Coordinators fail to enter a Bid for resource that is required to bid in the full range of available Capacity consistent with 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. The Generated Bid will be created only after the Market Close for the DAM and will be based entirely on data in the Master File. The Scheduling Coordinator may view Generated Bids, but may not modify such Bids. The CAISO will provide notice to the Scheduling Coordinator of the use of a Generated Bid prior to Market Clearing of the IFM.

30.7.4 HASP and RTM Validation.

The HASP and RTM Bids will follow the same validation process implemented in the DAM except that the CAISO will not validate the Bid before and again after the Master File Data update. HASP and RTM Bids are only validated based on the current Master File Data on the relevant Trading Day.

30.8 ~~30.4.2~~ Validation of ~~Existing Contract~~ETC Self-Schedules.

ETC Self-Schedules shall be validated pursuant to the procedures set forth in Section 16.6. ~~Each Schedule submitted to the ISO by a Scheduling Coordinator representing a rights holder to an Existing Contract must include a valid contract reference number in accordance with Section 16.2.4A.1. If the Schedule includes an Inter-Scheduling Coordinator Trade, only one of the Scheduling Coordinators should submit a contract reference number. If a match of the Schedule's contract reference number is found in the ISO's database and the Schedule is consistent with the instructions submitted previously by the Responsible PTO, the Schedule will be implemented in accordance with the instructions. If a match of the Schedule's contract reference number cannot be found in the ISO's database or if both Scheduling~~

~~Coordinators which are parties to an Inter-Scheduling Coordinator Trade submit contract reference numbers, the ISO will issue an error message to the Scheduling Coordinator via the WEnet (as described in Section 30.4.1.1) and indicate the nature of the problem. The ISO will assist the Scheduling Coordinator, within reason, in resolving the problem so that the Scheduling Coordinator is able to submit the Schedule successfully as soon as possible within the ISO's timing requirements of the SP. If the Scheduling Coordinator uses a contract reference number for which the responsible PTO has not reserved transmission capacity on a particular path (i.e., the contract reference Number(s) included on a contract usage template cannot be found in the ISO's scheduling applications table of contract reference numbers), the Scheduled use will be invalidated and the Scheduling Coordinator notified by the ISO's issuance of an invalidated usage information template.~~

30.9 ~~30.4.4~~ Validation of Ancillary Services Bids.

Throughout the validation process described in Section 30.7, ~~T~~the CAISO will verify that each Ancillary Services Bid ~~Schedule or bid~~ conforms to the content, format and syntax specified for the relevant ~~service~~Ancillary Service. If the Ancillary Services Bid~~Schedule or bid~~ does not so conform, the CAISO will send a notification to the Scheduling Coordinator notifying the Scheduling Coordinator of the errors in the ~~Schedules and/or bids~~Bids as described in Section 30.7. ~~Scheduling Coordinators will comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Ancillary Services Schedules and bids. Shown below are the two stages of validation carried out by the ISO:~~

~~**30.4.4.1 Stage One Validation.**During stage one validation, each incoming Ancillary Services schedule or bid will be validated to verify proper content, format and syntax.~~ When the Bids are submitted, ~~A~~a technical validation will be performed to verify that the ~~a schedule or~~ bid quantity of Regulation, Spinning Reserve, or Non-Spinning Reserve ~~or Replacement Reserve~~ does not exceed the available capacity for Regulation, or Operating Reserves ~~and Replacement Reserve~~ on the Generating Units, System Units, ~~Curtailable Demands~~Participating Loads and external imports/exports ~~scheduled or~~ bid. The Scheduling Coordinator will be notified ~~immediately~~within a reasonable time ~~through WEnet~~ 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 ~~via WEnet~~.

30.10 ~~30.4.6~~ 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 ~~nine~~ four segments ~~defined by a set of 1 to 10 pairs, e.g., (50,1),(100,3),(200,2), (300,2)~~. There is no monotonicity requirement for the operational ramp rate. The submitted operational ramp rate shall be validated as follows:

(a) 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 ~~that day~~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 ~~hour~~ Trading Hour must be the same with the one(s) submitted earlier for previous ~~hours~~ Trading Hours in the same Trading Day.

(f) Outages that affect the submitted operational ramp rate must be due to physical constraints, reported in SLIC 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) If an operational ramp rate is derated in SLIC, the ramp rate will only be to four segments. Ramping capability through Forbidden Regions are not affected by derates entered in SLIC.

(h) For all CAISO Dispatch Instructions of Reliability Must Run resources the operational ramp rate will be the ramp rate declared in the Reliability Must Run Contract Schedule A.

30.11 ~~30.4.7~~ Format and Validation of Startup and Shutdown Times.

For a Generating Unit, the submitted ~~startup~~ 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 ~~10~~ 3 segments defined by a set of 1 to ~~10~~ 4 down time and ~~startup~~ Start Up time pairs. The ~~startup~~ Start Up time is the time required to start the resource if it is offline longer than the corresponding down time. The last segment will represent the time to start the unit from a cold start and will extend to infinity. The submitted ~~startup~~ Start Up time function shall be validated as follows:

(a) The first down time must be 0 min.

(b) The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the maximum Start Up ~~startup~~ time function, as registered in the Master File for the relevant resource.

(c) The Start Up ~~startup~~ time for each segment must not exceed the Start Up ~~startup~~ time of the corresponding segment of the maximum Start Up ~~startup~~ time function, as registered in the Master File for the relevant resource.

(d) The Start Up ~~startup~~ time function must be strictly monotonically increasing, i.e., the Start Up ~~startup~~ time must increase as down time increases.

For ~~Curtailable Demand~~Participating Load, a single ~~shutdown~~ Shut Down time in minutes is the time required for the resource to ~~shut down~~Shut Down after receiving a Dispatch Instruction.

30.12 ~~30.4.8~~ Format and Validation of ~~Startup~~ Start Up and Shut Down ~~Shutdown~~ Costs.

For a Generating Unit, the submitted ~~startup~~ Start Up ~~cost~~ Cost expressed in dollars ($) as a function of down time expressed in minutes ~~(min)~~ must be a staircase function with up to ~~10~~ 3 segments defined by a set of 1 to ~~10~~4 down time and ~~startup~~ Start Up ~~c~~Cost pairs. The ~~startup cost~~Start Up Cost is the cost incurred to start the resource if it is offline longer than the corresponding down time. The last segment will represent the cost to start the resource from cold ~~startup~~ Start Up and will extend to infinity. The submitted ~~startup~~ Start Up Cost~~cost~~ function shall be validated as follows:

(a)~~•~~ The first down time must be 0 min.

(b)~~•~~ The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the cost-based Start Up Cost ~~startup~~ function, as registered in the Master File for the relevant resource.

(c)~~•~~ The Start Up Cost~~startup cost~~ for each segment must not be negative and must not exceed the Start Up Cost~~startup cost~~ of the corresponding segment of the cost-based Start Up Cost ~~startup cost~~ function, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based startup cost function shall be derived from the startup fuel function, as registered in the Master File for the relevant resource, and the applicable gas price index as approved by FERC.

(d)~~•~~ The Start Up Cost~~startup cost~~ function must be strictly monotonically increasing, i.e., the Start Up Cost ~~startup cost~~ must increase as down time increases.

For ~~Curtailable Demand~~Participating Loads, a single Shut Down Cost ~~shutdown cost~~ in $ is the cost incurred to Shut Down Cost ~~shut down~~ the resource after receiving a Dispatch Instruction. The submitted Shut Down Cost ~~shutdown cost~~ must not be negative.

30.13~~30.4.9~~ Format and Validation of Minimum Load Costs.

For a Generating Unit, the submitted Minimum Load Cost expressed in dollars per hour ($/hr) is the cost incurred for operating the unit at minimum load. The submitted Minimum Load Cost must not be negative and must not exceed the cost-based Minimum Load Cost, as registered in the Master File for the relevant resource. ~~For gas-fired resources, the cost-based Minimum Load Cost shall be derived pursuant to Section 40.1.6.1.2.~~

For ~~Curtailable Demand~~Participating Loads, the submitted Minimum Load Cost ($/hr) is the cost incurred while operating the resource at reduced consumption after receiving a Dispatch Instruction. The submitted Minimum Load Cost must not be negative.

30.14 ~~30.3.5~~ Prohibition on ~~Scheduling~~ Bidding Across Out-of-Service Transmission Paths at Scheduling Points.

Scheduling Coordinators shall not submit any Bids or ETC Self-Schedules at Scheduling Points ~~Schedule~~

using a transmission path for any Settlement Period for which the Operating Transfer Capability for that path is zero MW. The ~~ISO~~ CAISO shall reject ~~Schedules~~ Bids or ETC Self-Schedules submitted at Scheduling Points where ~~for transmission paths on which~~ the Operating Transfer Capability on the transmission path is zero MW. If the Operating Transfer Capability of a transmission path at the relevant Scheduling Point is reduced to zero after ~~Final~~ Day-Ahead Schedules have been ~~submitted~~issued, then, if time permits, the ~~ISO~~ CAISO shall direct the responsible Scheduling Coordinators to reduce all MWh associated with the Bids~~Schedules~~ on such zero-rated transmission paths to zero in the ~~Hour-Ahead Market~~HASP. As necessary to comply with Applicable Reliability Criteria, the ~~ISO~~ CAISO shall reduce any non-zero ~~Final Hour-Ahead~~HASP Bids ~~Schedules~~ across zero-rated transmission paths to zero after the ~~close~~ Market Close for the HASP~~of the Hour-Ahead Market~~. ~~No Usage Charges will be assessed, nor will any Usage Charges for counter-flow be paid, for Schedules across a path with an Operating Transfer Capability of zero.~~

31 DAY-AHEAD MARKET.

The DAM consists of the following functions performed in sequence: the MPM-RRD, IFM, and RUC. Scheduling Coordinators may submit Bids for Energy, Ancillary Services and RUC Capacity for an applicable Trading Day.

31.1 Bid Submission and Validation in the Day-Ahead Market.

Scheduling Coordinators submit a single Bid to be used in the DAM, which includes the MPM-RRD, the IFM and RUC. Scheduling Coordinators may submit Bids for the DAM as early as seven (7) days ahead of the targeted Trading Day and up to Market Close of the DAM for the target 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 RA Capacity as required in Section 40. Bids for Ancillary Services that are not Submissions to Self-Provide an Ancillary Service in the DAM must also contain a Bid for Energy.

~~**31.1.1 Reliability Must Run Information.**~~

~~By no later than 5:00 a.m. on the day before the Trading Day, the ISO will notify Scheduling Coordinators for Reliability Must-Run Units of the amount and time of Energy requirements from specific Reliability Must-Run Units that the ISO requires to deliver Energy in the Trading Day to the extent that the ISO is aware of such requirements (the "RMR Dispatch Notice"). The Energy to be delivered for each hour of the Trading Day pursuant to the RMR Dispatch Notice (including Energy the RMR Owner is entitled to substitute for Energy from the Reliability Must-Run Unit pursuant to the RMR Contract) shall be referred to as the "RMR Energy".~~

~~**31.1.1.1** No later than 6:00 a.m. on the day before the Trading Day, any RMR Owner receiving an RMR Dispatch Notice as indicated in this Section 31.1.1.1 (the "Applicable RMR Owner") must notify the ISO through the RMR Owner's Scheduling Coordinator (the "Applicable RMR SC"), with regard to each hour of the Trading Day identified in the RMR Dispatch Notice whether it intends to satisfy its obligation to deliver RMR Energy (i) by delivering RMR Energy pursuant to a market transaction ("RMR Market Energy"), and receiving only market compensation therefore (the "RMR Market Option"), or (ii) by delivering RMR Energy as a contract transaction ("RMR Contract Energy"), and accepting payment under~~

~~the relevant RMR Contract (the "RMR Contract Option"). If the Applicable RMR Owner so notifies the ISO by March 1, 2001, for calendar year 2001, and by January 1 of any subsequent calendar year, the RMR Owner may during that calendar year notify the ISO directly of its choice of payment option, rather than through the Applicable RMR Owner's Scheduling Coordinator. If the Applicable RMR Owner elects to provide notice of its choice of payment option directly, the ISO will not accept notice from the Applicable RMR Owner's Scheduling Coordinator during the relevant calendar year. Notwithstanding anything to the contrary in any RMR Contract, the Applicable RMR Owner may not elect to satisfy its obligation to deliver the RMR Energy specified in the RMR Dispatch Notice by delivering that RMR Energy pursuant to a transaction in the Real Time Market.~~

~~**31.1A.1** If, despite the variation of any time requirement or the omission of any step, the ISO either fails to receive sufficient Schedules to operate the Day-Ahead Market or is unable to perform Congestion Management in the Day-Ahead Market, the ISO may abort the Day-Ahead Market and require all Schedules to be submitted, and Congestion Management to be performed, in the Hour-Ahead Market.~~

~~**31.1A.2** If, despite the variation of any time requirement or omission of any step, the ISO either fails to receive sufficient Schedules to operate the Hour-Ahead Market or is unable to perform Congestion Management in the Hour-Ahead Market, the ISO may abort the Hour-Ahead Market and function in real time.~~

~~**31.1.2 RMR Contract Option.**~~

~~For each hour for which the Applicable RMR Owner elects the RMR Contract Option, the Scheduling Coordinator shall submit a Day-Ahead Energy Schedule that includes all RMR Contract Energy. Any RMR Contract Energy not Scheduled to forecast Demand or through Inter-Scheduling Coordinator Energy Trades shall be balanced by also Scheduling an additional quantity of Demand equal to the remaining amount of RMR Contract Energy at a Load Point specified by the ISO for each RMR Unit (the "RMR Contract Energy Load Point"). The RMR Contract Energy Load Point shall be used solely for the purpose of balancing the RMR Contract Energy not otherwise Scheduled to forecast Demand or an Inter-Scheduling Coordinator Energy Trade. The price for the RMR Contract Energy Scheduled to the RMR Contract Energy Load Point shall be the price paid to Demand deviations from Final Hour-Ahead~~

~~Schedules. The ISO shall post the list of RMR Contract Energy Load Points on the ISO Home Page and shall make any modifications to that list effective only 1) after providing at least five (5) days notice and 2) on the first day of a month. Whether or not the RMR Contract Energy is in the Final Schedule, the Applicable RMR Owner must deliver the RMR Contract Energy pursuant to the RMR Dispatch Notice. Notwithstanding anything to the contrary in the RMR Contract, neither the Applicable RMR Owner nor the Applicable RMR Scheduling Coordinator shall be entitled to any payment from any source for RMR Energy that is not scheduled as required by this Section 31.1.2. All RMR Energy delivered under this option shall be deemed delivered under a Nonmarket Transaction for the purposes of the RMR Contract. In the event that the RMR Contract Energy is not delivered for any hour, (i) if the RMR Contract Energy had been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and the Applicable RMR Scheduling Coordinator shall pay for the Imbalance Energy necessary to replace that RMR Energy; and (ii) if the RMR Contract Energy had not been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and, if the variable costs saved by the Owner's failure to deliver the RMR Contract Energy (which shall be equal to the Variable Cost Payment determined pursuant to Schedule C in the RMR Contract) are greater than the foregone Availability Payment under the RMR Contract, the Applicable RMR Owner shall pay the difference between the variable costs saved and the Availability Payment.~~

~~31.1.2.1 [Not Used]~~

~~31.1.3 RMR Market Option.~~

~~This Section 34.1.3 provides how an Applicable RMR Owner electing the RMR Market Option shall satisfy its obligation to deliver RMR Energy.~~

~~**31.1.3.1** For each hour for which an Applicable RMR Owner has selected the Market Option, the Applicable RMR Owner (i) may bid into a power exchange market any amount of the RMR Market Energy and (ii) may schedule as a bilateral Day-Ahead transaction any amount of RMR Market Energy.~~

~~The Preferred Day-Ahead Schedule of the Applicable RMR Scheduling Coordinator shall include as RMR Market Energy for each hour the sum of the amount awarded to the Applicable RMR Owner in any power exchange market for that hour and the amount scheduled as a bilateral Day-Ahead transaction for that hour. If the Preferred Day-Ahead Schedule of the Applicable RMR Scheduling Coordinator for any hour~~

~~includes Adjustment Bids for the RMR Unit, the Adjustment Bid shall specify the RMR Market Energy as the minimum MW output to which the Applicable RMR Scheduling Coordinator will allow the RMR Unit to be redispatched for that hour.~~

~~Notwithstanding anything to the contrary in the RMR Contract, neither the Applicable RMR Owner nor the Applicable RMR Scheduling Coordinator shall be entitled to any payment from any source for RMR Market Energy that is not bid and scheduled as required by this Section 31. In the event that the RMR Market Energy is not delivered, (i) if the RMR Market Energy had been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and the Applicable RMR Scheduling Coordinator shall pay for the Imbalance Energy necessary to replace that RMR Market Energy, or (ii) if the RMR Market Energy had not been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and, if the variable costs saved by the Owner's failure to deliver the RMR Market Energy (which shall be equal to the Variable Cost Payment determined pursuant to Schedule C in the RMR Contract) are greater than the foregone Availability Payment under the RMR Contract, the Applicable RMR Owner shall pay the difference between the variable costs saved and the Availability Payment.~~

~~**31.1.3.2** If the Applicable RMR Scheduling Coordinator's Preferred Day-Ahead Schedule does not include the entire amount of RMR Market Energy for any hour, the Applicable RMR Owner shall bid all remaining RMR Market Energy for that hour, net of any RMR Energy the Applicable RMR Owner elects to provide through an Hour-Ahead bilateral transaction for that hour, into the next available power exchange market for such hour at zero dollars per MWh.~~

~~**31.1.3.2.1** The Applicable RMR Scheduling Coordinator's Preferred Hour-Ahead Schedule for each hour shall include all RMR Market Energy specified in the RMR Dispatch Notice for that hour, except for the amount of RMR Energy that the Applicable RMR Owner was required to bid into the power exchange markets under Section 31.1.3.2 but was not awarded in such power exchange markets for such hour. If the Preferred Hour-Ahead Schedule of the Applicable RMR Scheduling Coordinator for any hour includes Adjustment Bids for the RMR Unit, the Adjustment Bid shall specify the RMR Market Energy as the minimum MW output to which the Applicable RMR Scheduling Coordinator will allow the RMR Unit to be redispatched for that hour.~~

~~**31.1.3.3** Whether or not the RMR Energy is in a Final Schedule, the Applicable RMR Owner must deliver the RMR Energy pursuant to the RMR Dispatch Notice. If the RMR Owner has bid and scheduled the RMR Energy as required by this Section 31, any RMR Energy provided but not included in the Final Schedule will be paid as Uninstructed Imbalance Energy. Notwithstanding anything to the contrary in the RMR Contract, neither the Applicable RMR Owner nor the Applicable RMR Scheduling Coordinator shall be entitled to any payment from any source for RMR Market Energy that is not bid and scheduled as required by this Section 31.~~

~~**31.1.3.4** If, at any time after 5:00 a.m. on the day before the Trading Day, the ISO determines that it requires additional Energy from specific Reliability Must-Run Units during the Trading Day, the ISO will notify Scheduling Coordinators for such Reliability Must-Run Units of the amount and time of the additional Energy requirements from such Reliability Must-Run Units (the "Supplemental RMR Dispatch Notice"). If the owner of the RMR Unit or the Applicable RMR Scheduling Coordinator for the RMR Unit specified in the Supplemental RMR Dispatch Notice has not already notified the ISO of a payment option for any hour of the Trading Day included in the Supplemental Dispatch Notice at the time the Supplemental Dispatch Notice is issued, the RMR Owner shall do so no later than three hours before the hour specified in the Supplemental RMR Dispatch Notice for each such hour that is at least four hours after the issuance of the Supplemental Dispatch Notice. If the RMR Owner elects to provide the Energy requested in the Supplemental RMR Dispatch Notice as RMR Contract Energy, the Scheduling Coordinator shall 1) submit an Hour-Ahead Energy Schedule that includes all or part of the RMR Contract Energy requested in the Supplemental RMR Dispatch Notice in a bilateral transaction to Demand or in an Inter-Scheduling Coordinator Energy Trade and 2) submit an Hour-Ahead Energy Schedule for all RMR Contract Energy requested in the Supplemental RMR Dispatch Notice not Scheduled in a bilateral transaction as a Schedule to the RMR Contract Energy Load Point and balance that Schedule by also Scheduling an additional quantity of Demand equal to the remaining amount of RMR Contract Energy at the RMR Contract Energy Load Point. The RMR Contract Energy Load Point shall be used solely for the purpose of balancing the RMR Contract Energy not otherwise Scheduled to forecast Demand or through an Inter-Scheduling Coordinator Energy Trade. The price for the RMR Contract Energy Scheduled to the~~

~~RMR Contract Energy Load Point shall be the price paid to Demand deviations from Final Hour-Ahead Schedules.~~

~~31.1.3.5 [Not Used]~~

~~31.1.5~~ ~~The Preferred Schedule of each Scheduling Coordinator for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day together with any Adjustment Bids and Ancillary Services bids.~~

~~31.1.6~~ ~~In submitting its Preferred Schedule, each Scheduling Coordinator shall notify the ISO of any Dispatchable Loads which are not scheduled but have submitted Adjustment Bids and are available for Dispatch at those same Adjustment Bids to assist in relieving Congestion.~~

~~31.1.7 ISO Analysis of Preferred Schedules.~~

~~On receipt of the Preferred Schedules, the ISO will analyze the Preferred Schedules of Applicable RMR Scheduling Coordinators to determine the compatibility of such Preferred Schedules with the RMR Dispatch Notices. The ISO shall notify the Scheduling Coordinator of any specific Reliability Must-Run Units which have not been included in the Preferred Schedule but which the ISO requires to run in the next Trading Day. The ISO will also notify the Scheduling Coordinator of any Ancillary Services it requires from specific Reliability Must-Run Units under their Reliability Must-Run Contracts in the next Trading Day. If the ISO identifies mismatches in the scheduled quantity or location for any Inter-Scheduling Coordinator Energy Trade, it will notify the Scheduling Coordinators concerned and give them until a specified time, which will allow them approximately one half-hour, in which to modify their Schedules to resolve the mismatch before it applies the provisions of Section 30.2.3.4. The ISO shall analyze the combined Preferred Schedules submitted by all Scheduling Coordinators to forecast the probability of Congestion being caused by the Preferred Schedules. If the ISO finds that the Preferred Schedules will not cause Congestion, and subject to Section 30.2.3.4, the Preferred Schedules shall become the Final Schedules and the ISO shall notify Scheduling Coordinators accordingly.~~

~~31.1.8 Issuance of Suggested Adjusted Schedules.~~

~~If the ISO finds that the Preferred Schedules would cause Congestion, it shall issue Suggested Adjusted Schedules no later than 11:00 a.m. on the day preceding the Trading Day. The ISO will include in the Suggested Adjusted Schedules the resolution of any mismatches in Inter-Scheduling Coordinator Energy~~

~~Trades, as determined by the ISO.~~

~~31.1.9 Submission of Revised Schedules.~~

~~If the ISO has issued Suggested Adjusted Schedules, by 12:00 noon on the day preceding the Trading Day, each Scheduling Coordinator may submit a Revised Schedule to the ISO or shall inform the ISO that it does not wish to make any change to its previously submitted Preferred Schedule. If the ISO identifies mismatches in the scheduled quantity or location for any Inter-Scheduling Coordinator Energy Trade, it will notify the Scheduling Coordinators concerned and give them until a specified time, which will allow them approximately one half-hour, in which to modify their Schedules to resolve the mismatch before it applies the provisions of Section 30.2.3.4.~~

~~31.1.9.1 Revised Schedules Become Final Day-Ahead Schedules.~~

~~Subsequent to receiving Revised Schedules if the ISO identifies no Congestion on the ISO Controlled Grid and subject to Section 30.2.3.4, the Revised Schedules and any unamended Preferred Schedules shall become Final Day-Ahead Schedules and the ISO shall notify Scheduling Coordinators accordingly.~~

~~31.1.9.2 Use of Congestion Management for Final Schedule.~~

~~Subsequent to receiving Revised Schedules if the ISO identifies Congestion on the ISO Controlled Grid, it shall use the Congestion Management provisions of this ISO Tariff to develop the Final Day-Ahead Schedules.~~

31.2 Market Power Mitigation and Reliability Requirement Determination (MPM-RRD). .

After the Market Close of the DAM, and after the CAISO has validated the Bids pursuant to Section 30.7, the CAISO will perform the MPM-RRD procedures in a series of processing runs that occur prior to the IFM Market-Clearing run. The MPM process determines which Bids need to be mitigated in the IFM. The RRD process determines RMR requirements for RMR Units. The MPM-RRD process optimizes resources using the same optimization used in the IFM, but instead of using Demand Bids as in the IFM the MPM-RRD process optimizes resources to meet one hundred percent of the CAISO Demand Forecast and Export Bids to the extent that the Export Bids are economic, and meet one hundred percent of Ancillary Services requirements based on Supply Bids submitted to the DAM. The pool of resources committed in the MPM-RRD process is then passed to the IFM to constitute the pool of resources available for commitment in the IFM. The CAISO performs the MPM-RRD for the DAM for the 24 hours of the next Trading Day.

31.2.1 The Reliability and Market Power Mitigation Runs.

The first run of the MPM-RRD procedures is the Competitive Constraint Run (CCR), in which only limits on transmission lines pre-designated as competitive are enforced. The only RMR units considered in the CCR are Condition 1 RMR units that have provided market Bids for the DAM. The second run is the All Constraints Run (ACR), during which the all transmission constraints are enforced. All RMR units, Condition 1 and Condition 2, are considered in the ACR. The resources committed in the ACR form the pool of resources that is available for commitment in the IFM.

31.2.2 Bid Mitigation.

The CAISO shall compare the resource dispatch levels derived from CCR and ACR and will mitigate Bids as follows.

31.2.2.1 RMR Units.

For a Condition 1 Unit that is dispatched in the CCR, the Bid used in the ACR for the entire portion of the unit's Bid above the CCR dispatch level and below the Maximum Net Dependable Capacity specified in the RMR Contract will be set to the lower of the RMR Proxy Bid, or the DAM Bid, but not lower than the unit's highest Bid price that cleared the CCR. If a Condition 1 Unit is dispatched in the CCR and receives a greater dispatch in the ACR, the entire portion of the unit's Bid curve above the CCR dispatch level and below the Maximum Net Dependable Capacity specified in the RMR Contract, will be set to the lower of the RMR Proxy Bid or the DAM Bid, but not lower than the unit's highest Bid price that cleared the CCR for purposes of being considered in the IFM. For purposes of the MPM-RRD, RMR Condition 1 Units will be treated like non-RMR Units with respect to any capacity in excess of the Maximum Net Dependable Capacity specified in the RMR Contract. For Condition 1 RMR Units, the market Bid at and below the CCR dispatch level will be retained in the IFM. For Condition 2 RMR Units and for Condition 1 RMR Units that either did not submit DAM Bids or submitted DAM Bids but were not dispatched in the CCR, the CAISO will use the RMR Proxy Bid in the ACR to determine the Energy required from RMR Units for each Trading Hour. If the dispatch level produced through the ACR for a Condition 1 RMR Unit is not greater than the dispatch level produced through CCR, the Unit's original, unmitigated DAM Bid will be retained in its entirety. For a Condition 1 RMR Unit, if the dispatch level produced through the ACR is greater than the dispatch level produced through the CCR, and for a Condition 2 RMR Unit that is dispatched through the CCR, the resource will be flagged as an RMR Dispatch in the Day-Ahead Schedule and shall constitute a Dispatch Notice pursuant to the RMR Contract.

31.2.2.2 Non-RMR Units.

If the dispatch level produced through the ACR is greater than the dispatch level produced through CCR, then the resource is subject to Local Market Power Mitigation, in which case the entire portion of the unit's Bid curve that is above the CCR dispatch level will be mitigated to the lower of the Default Energy Bid as specified in Section 39, or the DAM Bid, but no lower than the unit's highest Bid price that cleared the CCR.

31.3 Integrated Forward Market.

After the MPM-RRD and prior to RUC, the CAISO shall perform the IFM. The IFM performs Unit Commitment and Congestion Management, clears the Energy Bids as modified and in the MPM-RRD, taking into account transmission limits and technical and inter-temporal operating constraints, and ensures that adequate Ancillary Services are procured in the CAISO Control Area to meet 100 percent of the CAISO Forecast of CAISO Demand requirements. The IFM utilizes a set of integrated programs that: (1) determine Day-Ahead Schedules 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 based on multi-part supply Bids (including a Start-Up Bid, Minimum Load Bid, and Energy Bid Curve), and a capacity reservation Bid for Ancillary Services as well as Self-Schedules submitted by Scheduling Coordinators. The IFM also provides for the optimal management of Use-Limited Resources.

31.3.1 Market Clearing and Price Determination.

31.3.1.1 The IFM produces: (1) a set of hourly Day-Ahead Schedules, 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 the ASMPs for Ancillary Services to be used for settlement of the IFM. The CAISO will publish the LMPs at each PNode as calculated in the IFM. In determining Day-Ahead Schedules, AS Awards, and AS Schedules the IFM optimization will minimize production 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 Economic Bids without adjusting Self-Schedules, and adjusts Self-Schedules only if it is not possible to balance Supply and Demand and manage Congestion with available Economic Bids.

31.3.1.2 Reduction of LAP Demand

To the extent the CAISO cannot resolve a non-competitive transmission constraint utilizing effective Economic Bids such that Load at the LAP level in the pre-IFM Pass 2 (ACR) would otherwise be adjusted to relieve the constraint, the CAISO will take the following actions in sequence:

1) Step 1: 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 RMR or Resource Adequacy. Since the otherwise Self-Provided Ancillary Services capacity in question is under a must offer obligation, the associated Energy bid prices will be either: (a) submitted Energy Bids; or (b) Default Energy Bids to the extent an energy was not submitted for the Self Provided Ancillary Services capacity, but not lower than any Energy Bids from the same resource that may have cleared Pre-IFM Pass 1 (ACR).

2) Step 2: In case the measure in Step 1 is insufficient to avoid adjustment of Load at the LAP level, the CAISO will evaluate the validity of the binding constraint and if it is determined that the constraint can be relaxed based on the operating practices, will relax the constraint consistent with operating practices.

3) Step 3: In case the measures in Step 1 and Step 2 are insufficient, the CAISO may "soften" the LDF constraints on a Node or sub-LAP basis, i.e., adjust Load at individual Nodes or, in aggregate, a group of Nodes to relieve the constraint in such a way that minimizes the quantity of load curtailed.

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 constraints within each MSS. The Full Network Model (FNM) includes a full model of MSS transmission networks used for power flow calculations and constraint management in the IFM and RTM. Network constraints (i.e. circuit ratings, thermal ratings, etc.) within the MSS, or at the its boundaries, shall be monitored but not enforced in the CAISO's FNM. 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 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 network constraints will be handled. Costs associates with internal Congestion and Transmission Losses in the MSS will be the responsibility of the MSS Operator. Costs associated with Congestion and Transmission Losses internal to the MSS are 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.

31.4 Uneconomic Adjustments 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 Economic Bids that can relieve Congestion. If all Economic Bids in the IFM are exhausted, resource Self-Schedules between the resource's Minimum Load and the first Energy level of the first Energy Bid point will be subject to uneconomic adjustments based on the scheduling priorities listed below. 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 (or regulating) limit (or lower regulating limit plus any qualified Regulation Down Award or Self-Provision of Ancillary Services, if applicable). Any schedules below the Minimum Load level are treated as fixed schedules and are not subject to uneconomic adjustments for Congestion management. The scheduling priorities for the IFM from highest priority (last to be adjusted) to lowest priority (first to be adjusted) are as follows:

(a) Reliability Must Run (RMR) pre-dispatch reduction;

(b) Day-Ahead TOR (balanced demand and supply reduction);

(c) Day-Ahead ETCs (balanced demand and supply reduction); Different ETC Priority Levels will be observed based upon global ETC priorities provided to the CAISO by the responsible PTOs;

(d) Other Self Scheduled Load reduction subject to Section 31.3.1.2;

(e) Day-Ahead Ahead Regulatory Must Run and Regulatory Must Take reduction;

(f) Other Self Scheduled Supply reduction; and

(g) Economic Demand and Supply Bids.

31.5 Residual Unit Commitment.

The CAISO shall perform the RUC process after the IFM. In the event that the IFM did not commit sufficient resources to meet CAISO Demand Forecast and account for other factors such as load forecast error, as described in the Business Practice Manuals, the RUC shall commit additional resources and identify additional RUC Capacity to ensure sufficient on-line resources to meet Demand for each hour of the next Trading Day. RUC Capacity is selected by a SCUC optimization that uses the same FNM used in the IFM to help ensure the deliverability of Energy from the RUC Capacity.

31.5.1 RUC Participation

31.5.1.1 Capacity Eligible for RUC Participation.

RUC participation is voluntary for Capacity that has not been designated as RA Capacity. Scheduling Coordinators may make such Capacity available for participation in RUC by submitting a RUC Availability

Bid, provided the Scheduling Coordinator has also submitted an Energy Bid for such Capacity into the IFM. Capacity from Non-Dynamic System Resources that has not been designated RA Capacity is not eligible to participate in RUC. Capacity from resources including System Resources that has been designated as qualified RA Capacity must participate in RUC. System Resources eligible to participate in RUC will be considered on an hourly basis; that is, RUC will not observe any multi-hour block constraints that may have been submitted in conjunction with Energy Bids to the IFM. RMR 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.

31.5.1.2 RUC Availability Bids: Scheduling Coordinators may only submit RUC Availability Bids for Capacity (above the minimum load) for which they are also submitting an Energy Bid to participate in the IFM. The RUC Availability Bid for the RA Capacity submitted by a Scheduling Coordinator must be $0/MW per hour for the entire RA Capacity. If the Scheduling Coordinator fails to submit a $0/MW per hour for RA Capacity, the CAISO will insert the $0/MW per hour for the full amount of RA Capacity for a given resource. Scheduling Coordinators may submit non-zero RUC Availability Bids for the portion of a resource's Capacity that is not RA Capacity.

31.5.1.3 RMR Resources. If a resource is determined to have an RMR requirement for any Trading Hour of the next day, either by the MPM-RRD process or by the CAISO through a manual RMR Dispatch Notice, and if any portion of the RMR requirement has not been cleared in the IFM, the entire portion of the RMR requirement will be represented as a RMR Self-Schedule in the RUC.

31.5.2 Metered Subsystem RUC Obligation.

MSS Operators are permitted to make an annual election to opt-in or opt-out of RUC participation. Prior to the deadline for the annual CRR Allocation and Auction process, as specified in Section 36, an MSS Operator shall notify the CAISO of its RUC participation option for the following CRR cycle.

31.5.2.1 MSS Operator Opts-In to RUC Procurement. If the MSS Operator opts-in to the RUC procurement process, the Scheduling Coordinator for the MSS will be treated like any other Scheduling Coordinator that Bids in the DAM with respect to RUC procurement by the CAISO and allocation of RUC costs. The CAISO will consider the CAISO forecast of the MSS Demand in setting the RUC procurement target, and the Scheduling Coordinator for the MSS will be responsible for any applicable allocation of costs related to the Bid Cost Recovery for RUC as provided in Section 11.8.

31.5.2.2 MSS Operator Opts-out of RUC Procurement. If an MSS Operator opts out of the RUC procurement process, the CAISO shall not consider the CAISO forecast of the MSS Demand in setting the RUC procurement target, and will not commit resources in RUC to serve the MSS Demand. The MSS Operator shall be responsible for meeting the Supply requirements for serving its Demand in accordance with this Section 31.5.2.2, and it will be exempt from the allocation of costs related to the Bid Cost Recovery for RUC as provided in Section 11.8. The MSS that opts out of the CAISO's RUC procurement will have two options for meeting the Supply requirements for serving its Demand, which it will select on an hourly basis depending on how it Self-Schedules its Demand in the DAM.

31.5.2.2.1 Based on CAISO Demand Forecast. If the Scheduling Coordinator for the MSS submits hourly Demand Self-Schedules in the DAM that are greater than or equal to the CAISO Demand Forecast for the MSS Demand, the Scheduling Coordinator will have met its Supply requirement for such hours and will be exempt from the allocation of costs related to the Bid Cost Recovery for RUC as provided in Section 11.8.

31.5.2.2.2 Not Based on CAISO Demand Forecast. If the Scheduling Coordinator for the MSS submits hourly Demand Self-Schedules in the DAM that are less than the CAISO Demand Forecast for the MSS Demand, the Scheduling Coordinator will be exempt from the RUC cost allocation but will be monitored for its compliance with the Supply requirement based on the following performance criteria. If the MSS Demand Self-Schedule in the IFM for a given Trading Hour is less than the CAISO Demand Forecast for the MSS Demand and less than the actual metered Demand of the MSS for that Trading Hour, then penalty points will be accrued as follows: (i) If the difference between the actual metered Demand and the IFM Self-Schedule in any hour is greater than the lesser of two (2) percent of the CAISO Demand Forecast for the MSS or five (5) MW, but less than the lesser of five (5) percent or ten (10) MW, then the Scheduling Coordinator for the MSS will have one (1) penalty point against it for each occurrence; (ii) if the difference in any hour is more than the lesser of five (5) percent or ten (10) MW, but less than the lesser of ten (10) percent or twenty (20) MW, then the Scheduling Coordinator for the MSS will have two (2) penalty points against it for each occurrence; (iii) if the difference in any hour is more than the lesser of ten (10) percent or twenty (20) MW, then the Scheduling Coordinator for the MSS will have five (5) penalty points against it for each occurrence. The maximum penalty points that can be accrued during a single Trading Day for each MSS will be five (5). A total of more than twenty (20) penalty points within twelve (12) consecutive months will require the MSS to opt-in to RUC for the remainder of the CRR Cycle and for the following CRR Cycle.

31.5.2.3 MSS Option to Bid RUC Capacity. The Scheduling Coordinator for the MSS Operator may submit RUC Availability Bids for the capacity of MSS Resources and receive RUC Availability Payments and RUC Cost Compensation for such capacity selected in RUC, subject to the same bidding and operational requirements as any other resources providing RUC capacity. This capability is not affected by the MSS Operator's decision to Opt-In to or Opt-Out of RUC per Sections 31.5.2.1 and 31.5.2.2.

31.5.3 RUC Procurement Target. The procurement target for RUC in any given Trading Hour will be determined based on the next day's hourly CAISO Forecast of CAISO Demand less the Energy scheduled in the Day-Ahead Schedule, and accounting for other factors, as appropriate, such as load forecast error and estimated incremental HASP Bids including those from PIRP resources. The RUC procurement target may also be adjusted by CAISO operators on a RUC zone basis. 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. The procedure for setting the RUC procurement target is specified in the Business Practice Manuals. RUC will take into account COG capacity for a COG unit that was partially scheduled in IFM, but will be available in HASP and RTM. RUC will also include PIRP resources.

31.5.4 RUC Procurement Constraints.

In addition to the resource constraints and network constraints employed by SCUC as discussed in Section 27.4.1, the CAISO shall employ the following three constraints in RUC:

(a) To ensure that sufficient RUC Capacity is procured to meet CAISO Forecast of CAISO 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 CAISO Demand and IFM Export Schedules. The CAISO may adjust the CAISO Forecast of CAISO Demand to increase the RUC procurement target if there is AS Bid insufficiency in the IFM.

(b) To ensure that RUC will neither commit an excessive amount of Minimum Load Energy nor procure an excessive amount of RUC Capacity from Scheduling Points the CAISO will verify that the sum of Day-Ahead Schedules, Schedules of Generation Units, net imports and Participating Loads plus the Minimum Load Energy committed by RUC is not greater than a configurable percentage of the system CAISO Forecast of CAISO Demand.

(c) The CAISO can limit the amount of RUC Capacity it will procure from resources that could otherwise be started during the Operating Day. The CAISO will verify that the total Day-Ahead Schedules and RUC Capacity from such resources is not greater than a configurable percentage of the total available capacity of all such resources.

31.5.5 Selection and Commitment of RUC Capacity. Capacity that is not already scheduled in the IFM may be selected as RUC Capacity through the RUC process of the DAM. 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 and Minimum Load Bids. RUC will not consider Start-Up and Minimum Load Bids for resources already committed in the IFM. The RUC Capacity of a resource is the incremental amount of capacity selected in RUC above the resource's Day-Ahead Schedule. The resource's Day-Ahead Schedule plus its RUC Capacity comprise the resource's RUC Schedule. The CAISO will only issue RUC Start-up Instructions to resources that must start 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 reverse commitments issued through the IFM. 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.

31.5.6 Eligibility for RUC Compensation. All RUC Capacity is eligible for the RUC Availability Payment except for: (i) RUC Capacity from RMR Units that has been designated as RMR Dispatch and included in RUC as a Self-Schedule; (ii) RA Capacity; and (iii) RUC Capacity that corresponds to the resource's Minimum Load 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 RMR Units that were not designated for RMR Dispatches and Resource Adequacy Units, are also eligible for RUC Cost Compensation, which includes Start-Up 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.

31.6 ~~31.1~~ Timing of Day-Ahead Scheduling.

31.6.1 ~~31.1A~~ The ~~ISO~~ CAISO may ~~in~~ at its sole discretion implement any temporary variation or waiver of the timing requirements of this Section 31 and Section 6.5.3~~.1~~ (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 ~~ISO~~ CAISO Controlled Grid during an actual System Emergency.

~~(ii) the ISO receives Schedules that require delay in performing Day-Ahead Market or Hour-Ahead Market evaluations, such as in the case of the ISO receiving Inter-Scheduling Coordinator Energy Trades that do not balance;~~

(ii~~i~~) because of error or delay, the CAISO requires additional time to fulfill its responsibilities ~~pursuant to Section 30.1.3 of the ISO Tariff;~~

(~~iv~~iii) problems with data or the processing of data cause a delay in receiving or issuing ~~Schedules~~ Bids or publishing information on the ~~WEnet~~CAISO's secure communication system;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing ~~Schedules~~ Day-Ahead Schedules or publishing information on the ~~WEnet~~CAISO's secure communication system.~~;~~

31.6.2 If the ~~ISO~~ CAISO temporarily implements a waiver or variation of such timing requirements, the CAISO will publish the following information on ~~WEnet~~ 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;

(iv) reasons for the temporary waiver or variation.

31.6.3 ~~**31.1A.1**~~ If, despite the variation of any time requirement or the omission of any step, the CAISO either fails to receive sufficient Bids ~~Schedules~~ ~~to operate the~~or fails to clear Day-Ahead Market ~~or is unable to perform Congestion Management in the Day-Ahead Market~~, the CAISO may abort the Day-Ahead Market and require all Bids ~~Schedules~~ to be submitted~~, and Congestion Management to be performed, in~~ in the HASP and RTM ~~Hour-Ahead Market~~.

31.6.4 ~~**31.1.4**~~ **Demand Information.**

By 6:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator shall provide to the CAISO a Demand Forecast specified by UDC Service Area for which it will ~~schedule~~ submit a Bid ~~deliveries~~ for each of the Settlement Periods of the following Trading Day. The CAISO shall aggregate the Demand information by UDC Service Area and transmit the aggregate Demand information to each UDC serving such aggregate Demand.

32 [Not Used]

~~**33 HOUR AHEAD.**~~

33. HOUR-AHEAD SCHEDULING PROCESS (HASP).

The HASP is the hour-ahead process during the Real-Time which consists of the following activities. The HASP includes a special hourly run of the Real-Time Unit Commitment (RTUC), which is also one of the component processes of the RTM. The RTUC utilizes a SCUC optimization and runs every 15 minutes, as fully described in Section 34. This Section 33 describes the special features of the specific hourly HASP run of the RTUC. The HASP combines provisions for the CAISO to issue hourly pre-dispatch instructions to System Resources that submit Energy Bids to the RTM and for the procurement of Ancillary Services on an hourly basis from System Resources, with provisions for Scheduling Coordinators to self-schedule changes to their the Day-Ahead Schedules as provided in Section 33.1, and submit Bids to export Energy at Scheduling Points. The HASP also performs the MPM-RRD procedure with respect to the Bids that will be used in the HASP optimization and in the RTM processes for the same Trading Hour.

33.1 Submission of Bids for the HASP and RTM. Scheduling Coordinators may submit Bids that will be used for the HASP and the RTM processes starting from the time Day-Ahead Schedules have been posted until seventy-five (75) minutes prior to each applicable Trading Hour in the Real-Time. The HASP and RTM processes do not accept Demand Bids for CAISO Demand, or Self-Schedules for exports other than those utilizing ETC or TOR rights. Export Bids that are not Self-Schedules may be submitted in HASP. The rules for submitted Bids specified in Section 30 apply to Bids submitted to the HASP and RTM. After the Market Close of the HASP and the RTM the CAISO performs a validation process consistent with the provisions set forth in Section 30.7. Bids submitted to the HASP and the RTM to supply Energy and Ancillary Services will be considered in the various HASP and RTM processes, including the MPM-RRD process, the HASP optimization, the STUC, the RTUC and the RTD.

33.2 The HASP Optimization. After the Market Close for the HASP and RTM for the relevant Trading Hour, the Bids have been validated and the MPM-RRD process has been performed, the HASP optimization determines feasible but non-binding HASP Advisory Schedules for Generating Units for each

15-minute interval of the Trading Hour, as well as binding hourly HASP Intertie Schedules and binding hourly HASP AS Awards from Non-Dynamic System Resources for that Trading Hour. The HASP may also commit resources whose Start-Up Time is within its Time Horizon. The HASP, like the other runs of the RTUC, utilizes the same SCUC optimization and FNM as the IFM, with the FNM updated to reflect changes in system conditions as appropriate, to ensure that HASP Intertie Schedules are feasible. Instead of clearing against Demand Bids as in the IFM, the HASP clears Supply against the CAISO Forecast of CAISO Demand plus submitted Export Bids. The HASP optimization also factors in forecasted unscheduled flow at the interties. The HASP optimization produces Settlement prices for hourly imports and exports to and from the CAISO Control Area reflected in the HASP Intertie Schedule and for the HASP AS Awards for System Resources.

33.3 Treatment of Self-Schedules in HASP. Scheduling Coordinators may submit Self-Schedules for Supply of Energy to the HASP. Scheduling Coordinators may not submit Self-Schedules for CAISO Demand or for exports to the HASP, except for exports that utilize TORs and ETC rights that have post-Day-Ahead scheduling rights, and except for Self-Schedules for wheel-throughs. The HASP optimization clears Bids, including Self-Schedules, while preserving all priorities in this process consistent with Section 31.4.   The HASP optimization does not adjust submitted Self Schedules unless it is not possible to balance Supply and the CAISO Forecast of CAISO Demand plus Export Bids and manage Congestion using the available Economic Bids, in which case the HASP performs non-economic adjustments to Self-Schedules. The MWh quantities of Self-Scheduled Supply that clear in the HASP constitute a feasible dispatch for the RTM at the time HASP is run, but the HASP results do not constitute a final schedule for Generating Units because these resources may be adjusted non-economically in the RTD if necessary to manage Congestion and clear Supply and Demand. Self-Schedules submitted for Generation Units that clear in the HASP will be issued HASP Advisory Schedules. Scheduling Coordinators representing RA-PIRP resources must submit Self-Schedules in HASP in accordance with the forecast provided by the independent Forecast Service Provider.

33.4 MPM-RRD for the HASP and the RTM. After the Market Close of the HASP and RTM, after the CAISO has validated the Bids pursuant to section 30.7, and prior to running the HASP optimization, the CAISO conducts the MPM-RRD process, the results of which will be utilized in the HASP optimization and all RTM processes for the Trading Hour. The MPM-RRD process for the HASP and RTM produces results for each fifteen-minute interval of the Trading Hour and thus may produce up to four mitigated Bids for any given resource for the Trading Hour. A single mitigated Bid for the entire Trading Hour is calculated using the minimum Bid price of the four mitigated Bid curves at each Bid quantity level. The Bids are mitigated only for the Bid quantities that are above the minimum quantity cleared in the CCR across all four 15-minute intervals. For a Condition 1 RMR Unit, if the dispatch level produced through the ACR is greater than the dispatch level produced through the CCR, and for a Condition 2 RMR Unit that is dispatched through the CCR, the resource will be flagged as an RMR Dispatch in the RTM and shall constitute a Dispatch Notice pursuant to the RMR Contract.

33.5 [NOT USED]

33.6 HASP Results. The CAISO publishes the binding HASP Intertie Schedules and HASP AS Awards for System Resources, as well as HASP Advisory Schedules and HASP AS Awards for internal Generating Units no later than 45 minutes prior to the Trading Hour.

33.7 Ancillary Services in the HASP and the RTUC. To maintain required Ancillary Services when changes in forecasts of Demand and resource outages occur after the Day-Ahead AS Awards are established, the CAISO utilizes the RTUC runs, including the HASP, to procure additional Ancillary Services needed to meet reliability criteria. The HASP meets the expected need for additional Ancillary Services for the Trading Hour by utilizing the optimal mix of Ancillary Services from System Resources and from Generating Units. Only the AS from System Resources are binding Awards, and these are for the full Trading Hour. Those Generating Units designated in the HASP to provide Ancillary Services for the same Trading Hour are given non-binding advisory awards as a result of the HASP because the use of Generating Units to provide AS will be re-optimized by a subsequent RTUC that is run closer to the time the AS will actually be needed, as described in Section 34.2. The HASP AS Awards for System Resources are settled at hourly ASMPs that are calculated in the HASP as described in Section 33.8. All Operating Reserves procured in HASP are Contingency Only Operating Reserves.

33.8 HASP Prices for HASP Intertie Schedules and HASP AS Awards. The RTUC will produce 15-minute LMPs for the four 15-minute intervals for the applicable Trading Hour. The 15-minute LMPs corresponding to the Scheduling Points are then used to derive a simple average hourly price for the Settlement of Hourly Intertie Schedules at each Scheduling Point. The RTUC will also produce 15-minute ASMPs for the four 15-minute intervals for the applicable Trading Hour. These 15-minute ASMPs are then used to derive an average hourly price for the Settlement of hourly HASP AS Awards. The RTUC run will also produce 15-minute Shadow Prices for each of the interties for the four 15-minute intervals for the applicable Trading Hour. These 15-minute Shadow Prices are then used to derive an average hourly price for charging Hourly Intertie AS Award providers for Congestion on the interties. HASP Intertie Schedules and HASP AS Awards are settled in accordance with Sections 11.4 and 11.10.1.2 respectively.

33.9 Cessation of the HASP

~~**31.1A.2**~~ If, despite the variation of any time requirement or omission of any step, the ~~ISO~~ CAISO ~~either fails to receive sufficient Schedules to operate the Hour-Ahead Market or is unable to perform Congestion Management in the Hour-Ahead Market~~is unable to operate the HASP, the ~~ISO~~ CAISO may abort the HASP ~~Hour-Ahead Market~~ and perform all required functions through the RTM processes. ~~and function in real time.~~

~~**33.1 Timing of Hour-Ahead Scheduling.**~~

~~**33.1.1. Submission of Preferred Schedule.**~~

~~Each Scheduling Coordinator's Preferred Schedule for each Settlement Period during a Trading Day together with any additional or updated Adjustment Bids or Ancillary Services bids shall be submitted at least two hours and fifteen minutes (i.e., 135 minutes) prior to the commencement of that Settlement Period.~~

~~**33.1.1.1 Statements in Preferred Schedule.**~~

~~In submitting its Preferred Schedule, each Scheduling Coordinator may submit Adjustment Bids for use in the Hour-Ahead Market to assist in relieving Congestion.~~

~~**33.1.1.2 Final Hour-Ahead Schedule Submission.**~~

~~Each Hour-Ahead Schedule shall indicate the changes which the relevant Scheduling Coordinator wishes to make to the Final Day-Ahead Schedule.~~

~~**33.1.2 ISO Analysis of Preferred Schedules.**~~

~~The ISO shall analyze the combined Preferred Schedules submitted by all Scheduling Coordinators to~~

~~forecast the probability of Congestion being caused by the Preferred Schedules.~~

~~**33.1.2.1 Preferred Schedules Become Final Hour-Ahead Schedules.**~~

~~If the ISO identifies no Congestion on the ISO Controlled Grid, the Preferred Schedules shall become Final Hour-Ahead Schedules and the ISO shall notify Scheduling Coordinators accordingly.~~

~~**33.1.2.2 Congestion Management Provisions for Final Hour-Ahead Schedules.**~~

~~If the ISO identifies Congestion, it shall use the Congestion Management provisions of Section 27.1.1 of this ISO Tariff to develop the Final Hour-Ahead Schedules.~~

~~**33.1.2.3 Final Hour-Ahead Schedules.**~~

~~The ISO shall inform each Scheduling Coordinator of its responsibilities to provide Ancillary Services in accordance with Section 8.7. Not later than thirty (30) minutes before the commencement of each Settlement Period, the ISO shall provide each Scheduling Coordinator with the Final Schedule for that Settlement Period. Each Final Schedule shall be a Balanced Schedule and shall contain the following information:~~

~~**33.1.2.3.1 Generation.**~~

~~**33.1.2.3.1.1** Name and identification number of each Participating Generator appearing in the Final Schedule;~~

~~**33.1.2.3.1.2** Location Code of each Generating Unit, System Resource and Scheduling Point;~~

~~**33.1.2.3.1.3** The changes in the final scheduled quantity (in MWh) for each such Generating Unit, System Resource and scheduled voltage;~~

~~**33.1.2.3.1.4** Notification if the scheduled Generation was adjusted to resolve Congestion; and~~

~~**33.1.2.3.1.5 [Not Used]**~~

~~**33.1.2.3.2 Load.**~~

~~**33.1.2.3.2.1** For each Load where a Demand Bid has been submitted, the Location Code of the Take-Out Point;~~

~~**33.1.2.3.2.2 Final Scheduled Quantity.** Final scheduled quantity (in MWh) of Demand; and~~

~~**33.1.2.3.2.3 Notification of Adjustment.** Notification if the scheduled Demand was adjusted to resolve Congestion.~~

~~**33.1.2.4 Usage Charges.** The ISO shall notify each Scheduling Coordinator of the applicable~~

~~Usage Charge calculated in accordance with Section 27.1.2.~~

~~**34 REAL-TIME.**~~

34. REAL-TIME MARKET.

The RTM is the market conducted by the CAISO during any given operating day in which Scheduling Coordinators may provide Real-Time Imbalance Energy and Ancillary Services. The Real-Time Market consists of the Real-Time Unit Commitment (RTUC), the Short-Term Unit Commitment (STUC) and the Real-Time Dispatch (RTD) processes. The Short-Term Unit Commitment (STUC) runs once per hour at the top of the hour and utilizes the SCUC optimization to commit Medium Start, Short-Start and Fast Start Resources to meet the CAISO Demand Forecast. The Time Horizon of the STUC is approximately 255 minutes, starting with the fourth 15-minute interval of the next Trading Hour and extending for the next four Trading Hours. The RTUC runs every 15 minutes and utilizes the SCUC optimization to commit Fast-Start and some Short-Start resources and to procure any needed AS on a 15-minute basis. Any given run of the RTUC will have a Time Horizon of approximately 60 to 105 minutes (four to seven 15-minute intervals) depending on when during the hour the run occurs. Not all resources committed in a given STUC or RTUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide energy when it is expected to be needed. The RTD uses a Security Constrained Economic Dispatch (SCED) algorithm every five minutes throughout the Trading Hour to determine optimal Dispatch Instructions to balance Supply and Demand and maintain required Ancillary Services quantities for the next binding target interval. The RTD optimization utilizes up to a 65-minute Time Horizon (13 five-minute intervals), but the CAISO issues Dispatch Instructions only for the next target five-minute Interval. The RTUC, STUC and RTD processes of the RTM use the same FNM used in the DAM and the HASP, subject to any necessary updates of the FNM pursuant to changes in grid conditions after the DAM has run.

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34.1 Inputs to the Real-Time Market. The RTM utilizes results produced by the DAM and HASP for each Trading Hour of the Trading Day, including the combined commitments contained in the Day-Ahead Schedules, Day Ahead AS Awards, RUC Awards, HASP Intertie Schedules, HASP Self-

Schedules, HASP Intertie AS Awards and the MPM-RRD that is run as part of the HASP to determine reliability needs and mitigated bids for each relevant Trading Hour. These results, plus the short-term Demand Forecast, Real-Time Energy Bids, Real-Time Ancillary Service Bids, updated FNM, State-Estimator output, resource outage and de-rate information constitute the inputs to the RTM processes.

~~**34.1 Energy Bids.**~~

~~**34.1.1 Energy Bid Definition.**~~

~~A single Energy Bid curve per resource per hour shall be used in: (a) the real-time Hourly Pre-Dispatch as set forth in Section 34.3.0.2, and (b) Dispatch in the Real Time Markets. A corresponding operational ramp rate as provided for in Section 30.4.6 shall be submitted along with the single Energy Bid curve and shall be used in determination of Dispatch Instructions pursuant to Section 34.3.1(c).~~

~~The Energy Bid shall be a staircase price ($/MWh) versus quantity (MW) curve of up to 10 segments. The Energy Bid shall be submitted to the real-time Imbalance Energy market using the Supplemental Energy Bid template. The Energy Bid curve shall be monotonically increasing, i.e., the price of a subsequent segment shall be greater than the price of a previous segment. Subject to the foregoing, sellers may increase or decrease bids in the ISO Real Time Market for capacity associated with those parts of the bid curve that were not accepted in or before the Hour-Ahead Market. For capacity associated with those parts of the bid curve previously accepted in or before the Hour-Ahead Market, sellers may only submit lower bids in subsequent markets. Each Forbidden Operating Region must be represented by only one bid segment.~~

~~**34.1.2 Energy Bid Submission.**~~

~~**34.1.2.1 Real Time Market.**~~

~~Bids shall be submitted for use in the real-time Hourly Pre-Dispatch Section 34.3.0.2(i) and the Real-Time Economic Dispatch up to sixty-two (62) minutes prior to the Operating Hour. Resources required to offer their Available Generation in accordance with Section 40.1.4 shall be required to submit Energy Bids for 1) all of their Available Generation and 2) any Ancillary Services capacity awarded or self-provided in the Day-Ahead or Hour-Ahead Ancillary Services markets. In the absence of submitted bids, default bids will be used for resources required to offer their Available Generation in accordance with Section 40.1.4.~~

~~Resources not required to offer their Available Generation in accordance with Section 40.1.4 that were awarded or self-provided Ancillary Services capacity must submit an Energy Bid for no less than the amount of awarded or self-provided Ancillary Services capacity. Resources not required to offer their Available Generation in accordance with Section 40.1.4 may voluntarily submit Energy Bids. Submitted Energy Bids shall be subject to the Damage Control Bid Cap as set forth in Section 39.1 and to the Mitigation Measures set forth in Attachment A to Appendix P.~~

~~34.1.2.2 Real-Time Energy Bid Partition.~~

~~The portion of the single 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; (c) Non-Spinning Reserve; and (d) Replacement 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 Supplemental Energy.~~

~~34.1.2.3 Creation of the Real-Time Merit Order Stack.~~

~~34.1.2.3.1 Sources of Imbalance Energy.~~

~~The following Energy Bids will be considered in the creation of the real-time merit order stack for Imbalance Energy:~~

~~(a) Supplemental Energy Bids;~~

~~(b) Ancillary Services Energy Bids (except for Regulation) submitted for specific Ancillary Services for those resources which have been selected in the ISO's Ancillary Services auction to supply such specific Ancillary Services; and~~

~~(c) Ancillary Services Energy Bids (except for Regulation) submitted for specific Ancillary Services for those resources which Scheduling Coordinators have elected to use to self-provide such specific Ancillary Services and for which the ISO has accepted such self-provision.~~

~~34.1.2.3.2 Stacking of the Energy Bids.~~

~~The sources of Imbalance Energy described in Section 34.1.2.3.1 will be arranged in order of increasing Energy Bid prices to create a merit order stack. This merit order stack will be arranged without regard to~~

~~the source of the Energy Bid except that Energy Bids associated with Spinning and Non-Spinning Reserve shall not be included in the merit order stack during normal operating conditions if the capacity associated with such bids has been designated as 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. In the event of an unplanned Outage, a Contingency or threatened or actual System Emergency, all Energy Bids associated with Spinning and Non-Spinning Reserve may be included in the merit order stack. In the event of Inter-Zonal Congestion, separate merit order stacks will be created for each Zone. The information in the merit order stack shall be provided to the real-time dispatcher through the RTD Software. Where, in any Settlement Interval, the highest decremental Energy Bid in the merit order stack is higher than the lowest incremental Energy Bid, the RTD Software will eliminate the Price Overlap by actually dispatching for all those incremental and decremental bids which fall within the overlap. References to incremental Energy Bids include references to Demand reduction bids, and for the purpose of applying this algorithm a reduction in Demand shall be treated as an equivalent increase in Generation.~~

~~34.1.2.3.3 Use of the Merit Order Stack.~~

~~The merit order stack, as described in Section 34.1.2.3.2, can be used to supply Energy for:~~

~~(a) satisfying needs for Imbalance Energy (differences between actual and scheduled Generation, Demand and external imports/exports) in real time;~~

~~(b) managing Inter-Zonal Congestion in real time;~~

~~(c) supplying Energy necessary to allow resources providing Regulation service to return to the base point of their regulating ranges in real time;~~

~~(d) recovering Operating Reserves utilized in real time;~~

~~(e) procuring additional Voltage Support required from resources beyond their power factor ranges in real time; and~~

~~(f) Dispatching System Resources and Dispatchable Loads and increasing Generating Units' output to manage Intra-Zonal Congestion in real time.~~

~~34.1.3 Requirement to Submit Energy Bids For Awarded or Self-Provided Ancillary Services Capacity.~~

~~Scheduling Coordinators for resources that have been awarded or self-provide Regulation Up, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity must submit a Supplemental Energy bid for at least all the awarded or self-provided Ancillary Services capacity. To the extent a Supplemental Energy bid is not so submitted for a gas-fired resource, the ISO shall calculate a Supplemental Energy bid in accordance with Section 40.1.8 and insert that bid into the real-time Imbalance Energy market. To the extent a Supplemental Energy bid is not so submitted for a non-gas-fired resource, the ISO shall insert a bid of $0/MWh into the real-time Imbalance Energy market.~~

34.2 Real-Time Unit Commitment.

The Real-Time Unit Commitment (RTUC) process uses SCUC and is run every 15 minutes to: (1) make commitment decisions for Fast-Start and Short-Start resources having Start-Up Times within the Time-Horizon of the RTUC process, and (2) procure required additional Ancillary Services and calculate ASMP used for settling procured Ancillary Service Capacity for the next 15 minute Real-Time Ancillary Service Interval. RTUC is run four times an hour, at the following times for the following Time Horizons: (1) at approximately 7.5 minutes prior to the next Trading Hour, in conjunction with the HASP run, for T-45 minutes to T+60 minutes; (2) at approximately 7.5 minutes into the current hour for T-30 minutes to T+60 minutes; (3) at approximately 22.5 minutes into the current hour for T-15 minutes to T+60 minutes; and (4) at approximately 37.5 minutes into the current hour for T to T+60 minutes where T is the beginning of the next Trade Hour. The HASP, described in Section 33, is a special RTUC run that is performed at approximately 7.5 minutes before each hour and has the additional responsibility of: (1) pre-dispatching Energy and awarding Ancillary Services for hourly dispatched System Resources for the Trading Hour that begins 67.5 minutes later, and (2) performing the necessary MPM-RRD for that Trading Hour.

34.2.1 Commitment of Fast Start and Short Start Resources.

RTUC produces binding and advisory Start-Up and Shut-Down Dispatch instructions for Fast-Start and Short-Start resources that have Start-Up Times that would allow the resource to be committed prior to the end of the relevant Time Horizon of the RTUC run. A Start-Up Dispatch instruction is considered binding if the resource could not achieve the target start time as determined in the current RTUC run in a subsequent RTUC run as a result of the Start-Up Time of the resource. A Start-Up instruction is considered advisory if it is not binding, such that the resource could achieve its target Start Time as determined in the current RTUC run in a subsequent RTUC run based on its Start-Up Time. A Shut-Down Instruction is considered binding if the resource could achieve the target Shut-Down Time as determined in the current RTUC in a subsequent RTUC run. A Shut-Down Dispatch Instruction is considered advisory if the resource Shut-Down Instruction is not binding such that the resource could achieve its target Shut Down time as determined in the current RTUC run in a subsequent RTUC run. A binding Dispatch Instruction that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up instruction by the CAISO Operator. An advisory Dispatch Instruction changing the Commitment Status of a resource may be modified by the CAISO Operator to a binding Dispatch Instruction and communicated in accordance with Section 6.3 after review and acceptance by the CAISO Operator. Only binding and not advisory Dispatch Instructions will be issued by the CAISO.

34.2.2 Real-Time Ancillary Services Procurement. If the CAISO determines that additional Ancillary Services are required, other than those procured in the DAM and the HASP, the RTUC will procure Ancillary Services on a 15-minute basis as necessary to meet reliability requirements and will determine Real-Time Ancillary Service Interval ASMPs for such AS for the next Commitment Period. All Operating Reserves procured in the RTM are considered Contingency Only Operating Reserves. All Ancillary Service awarded in RTUC will be taken as fixed for the three 5-minute RTD intervals of its target 15-minute interval. In the RTUC, all resources certified and capable of providing Operating Reserves that have submitted Real-Time Energy Bids shall also submit applicable Spin or Non-Spin Reserves Bids, respectively, depending on whether the resource is online or offline. The CAISO will utilize the RTUC to procure Operating Reserves to restore its Operating Reserve requirements in cases when: (1) Operating Reserves awarded in DAM or HASP have been dispatched to provide Energy, (2) resource(s) awarded to provide Operating Reserves in the DAM or HASP or no longer capable of providing such awarded Operating Reserves, or (3) the Operator determines that additional Operating Reserves are necessary to maintain Operating Reserves within WECC/MORC criteria. All resources certified and capable of providing Regulation that have submitted Real Time Energy bids shall also submit applicable Regulation Bids. The CAISO will utilize the RTUC to procure additional Regulation capacity in real-time in cases when: (1) resource(s) awarded to provide Regulation in the DAM or HASP are no longer capable of providing such awarded Regulation, or (2) the Operator determines that additional Regulation is necessary to maintain sufficient control consistent with NERC/WECC criteria and good utility practice.

~~34.2 Supplemental Energy Bids.~~

~~In addition to the Generating Units, Loads and System Resources which have been scheduled to provide Ancillary Services in the Day-Ahead and Hour-Ahead Markets, the ISO may Dispatch Generating Units, Loads or System Resources for which Scheduling Coordinators have submitted Supplemental Energy bids. Supplemental Energy bids are available to the ISO for procurement and use for Imbalance Energy, additional Voltage Support and Congestion Management in the Real Time Market.~~

~~34.2.1 Identification of Supplemental Energy Bids.~~

~~The upper portion of a Scheduling Coordinator's Energy Bid for a resource providing Spinning, Non-Spinning, or Replacement Reserves that corresponds to the resource's available capacity up to the highest operating limit, 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; c) Non-Spinning Reserve; and d) Replacement 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, if there is any, shall constitute Supplemental Energy.~~

~~34.2.1.1 Timing of Supplemental Energy Bids.~~

~~Supplemental Energy bids must be submitted to the ISO no later than sixty-two (62) minutes prior to the operating hour. Bids may also be submitted at any time after the Day-Ahead Market closes. These Supplemental Energy bids cannot be withdrawn after sixty-two (62) minutes prior to the Settlement Period. A System Resource that identifies its bid as a Hourly Pre-Dispatch bid will only be pre-dispatched and will not be subject to any intra-hour Redispatch except as necessary to maintain inter-Control Area transmission reliability.~~

~~34.2.1.1A Form of Supplemental Energy Bid Information.~~

~~Supplemental Energy bids must include the following information:~~

~~34.2.1.2 Generation Section of Energy Bid Data.~~ ~~Each Scheduling Coordinator offering Spinning, Non-Spinning, or Replacement Reserve, or Supplemental Energy to the ISO will submit the following information for each Generating Unit for each Settlement Period~~

~~(a) Scheduling Coordinator's ID code;~~

~~(b) name of Generating Unit;~~

~~(c) Generating Unit operating limits (high and low MW);~~

~~(d) Generating Unit operational ramp rate in MW/minute;~~

~~(e) Generating Unit startup time function in minutes;~~

~~(f) Generating Unit startup cost function in $/start;~~

~~(g) Generating Unit Minimum Load Cost in $/hr; and~~

~~(h) the MW and $/MWh values for each Generating Unit for which a Supplemental Energy bid is being submitted consistent with this ISO Tariff.~~

~~A Physical Scheduling Plant shall be treated as a single Generating Unit for Supplemental Energy bid purposes.~~

~~**34.2.1.3 Demand Section of Energy Bid Data.**~~

~~Each Scheduling Coordinator offering Spinning, Non-Spinning, or Replacement Reserve, or Supplemental Energy to the ISO will submit the following information for each Demand for each Settlement Period:~~

~~(a) Scheduling Coordinator's ID code;~~

~~(b) name of Demand;~~

~~(c) Demand shutdown time in minutes;~~

~~(d) Demand shutdown cost in $/start;~~

~~(e) Demand minimum curtailed load cost in $/hr; and~~

~~(f) the MW and $/MWh values for each Demand for which a Supplemental Energy bid is being submitted consistent with this ISO Tariff.~~

~~**34.2.1.4 External Import Section of Energy Bid Data.**~~

~~Each Scheduling Coordinator offering Spinning, Non-Spinning, or Replacement Reserve, or Supplemental Energy to the ISO will submit the following information for each external import for each Settlement Period:~~

~~(a) Scheduling Coordinator's ID code;~~

~~(b) name of Scheduling Point;~~

~~(c) interchange ID (the name of the selling entity, the buying entity, and a numeric identifier);~~

~~(d) external Control Area ID;~~

~~(e) Schedule ID (NERC ID number);~~

~~(f) complete WECC tag;~~

~~(g) operational ramp rate (MW/minute);~~

~~(h) the MW and $/MWh values for each external import for which a Supplemental Energy bid is being submitted consistent with this ISO Tariff;~~

~~(i) minimum block of hours that bid must be dispatched; \~~

~~(j) Flag indicating the bid must is capable available for intra-hour Redispatch. If this flag is set to no then the bid is indicating that the bid must be pre-dispatched and not re- dispatched during the real-time operating hour;~~

~~(k) interchange ID code;~~

~~(l) external Control Area ID;~~

~~(m) Schedule ID (NERC ID number) and complete WECC tag;~~

~~(n) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule; and~~

~~(o) the contract reference number, if applicable.34.2.1.4A Format of Energy Bids.~~

~~The Scheduling Coordinator's Final Hour-Ahead Schedule for each resource must be within the range of the Energy Bids. The minimum MW output level specified for a resource, which may be zero MW (or negative for pumped storage resources), and the maximum MW output level specified for a resource must be physically achievable by the resource. All submitted Energy Bids must be in the form of a monotonically increasing staircase function for Demands. These staircase functions will be composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of quantity/price information, with an operational ramp rate associated with the entire MW range as provided for in this ISO Tariff. Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Energy Bids.~~

~~34.2.1.4B Real Time Operational Activities in the Hour Prior to the Settlement Period.~~

~~34.2.1.5 Schedule Confirmation.~~

~~In the hour prior to the beginning of the Settlement Period, the ISO will review and evaluate the current system operating conditions to ensure sufficient Energy and Ancillary Services resources are available for the next Settlement Period. The ISO will:~~

~~(a) verify that each Scheduling Coordinator's Ancillary Services obligations are scheduled as required. The ISO will procure additional Ancillary Services if insufficient resources are scheduled;~~

~~(b) verify any Supplemental Energy bids received up to thirty (30) minutes prior to the Settlement Period, for increases or decreases in Energy output which it may require for the Settlement Period; and~~

~~(c) verify that with currently anticipated operating conditions there is sufficient transfer capacity on the ISO Controlled Grid to implement all Final Schedules.~~

~~34.2.1.6 Confirm Interchange Transaction Schedules (ITSs).~~

~~Also in the hour prior to the beginning of theSettlement Period the ISO will:~~

~~(a) adjust interchange transaction schedules (ITSs) as required under Existing Contracts in accordance with the procedures in the ISO Tariff for the management of Existing Contracts;~~

~~(b) adjust ITSs as required by changes in transfer capability of transmission paths occurring after close of the Hour-Ahead Market; and~~

~~(c) agree on ITS changes with adjacent Control Area Operators.~~

~~34.3 Real-Time Dispatch.~~

~~The ISO, using RTD Software, shall economically Dispatch each Generating Unit, Curtailable Demand, System Unit, Interconnection schedule or System Resource that is effective to: (i) meet Imbalance Energy requirements and eliminate any Price Overlap in real time, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.3.0.3, and (ii) relieve Congestion, if necessary, to ensure System Reliability and to maintain Applicable Reliability Criteria. The ISO shall determine that additional output is needed if the current output levels of the Regulation Generating Units, System Units, and System Resources deviate from their preferred operating points by more than a specified threshold (to be determined by the ISO), or to meet the projected Imbalance Energy requirements for the next Dispatch Interval. The ISO shall employ a multi-interval constrained~~

~~optimization methodology (RTD Software) to calculate an optimal dispatch for each Dispatch Interval within a time horizon that shall extend to the end of the next hour. The ISO shall Dispatch resources that have submitted Energy Bids over the time horizon to meet forecasted Imbalance Energy requirements minimizing the Imbalance Energy procurement cost over the entire time horizon, subject to resource and transmission system constraints. However, Dispatch Instructions shall be issued for the next Dispatch Interval only. The ISO also shall instruct resources to start up or shut down over the time horizon based on their submitted and validated Start-Up Fuel Costs, Minimum Load Costs and Energy Bids. These resources shall receive binding start-up or shut-down pre-dispatch instructions as required by their startup time. The ISO shall only start resources that can start within the time horizon. The ISO may shut down resources that do not need to be on-line if constraints within the time horizon permit. However, resources providing Regulation or Spinning Reserve shall not be shut down. On-line resources providing Non-Spinning or Replacement Reserve shall also not be eligible for shutdown, unless their minimum down time does not exceed 10 minutes.~~

~~34.3.0 Rules For Real-Time Dispatch of Imbalance Energy Resources.~~

~~34.3.0.1.1 Overview.~~

~~During real time, the ISO shall dispatch Generating Units, Loads and System Resources to procure Imbalance Energy. In addition, the ISO may also need to purchase additional Ancillary Services if the services arranged in advance are used to provide Imbalance Energy, and such depletion needs to be recovered to meet reliability contingency requirements.~~

~~34.3.0.1.2 Utilization of the Energy Bids.~~

~~The ISO will use the Energy Bids to Dispatch Supplemental Energy and Ancillary Services to procure balancing Energy for:~~

~~(a) satisfying needs for Imbalance Energy;~~

~~(b) mitigating Inter-Zonal Congestion;~~

~~(c) allowing resources providing Regulation service to return to the preferred operating point within their regulating ranges;~~

~~(d) allowing recovery of Operating Reserves utilized in real-time operations;~~

~~(e) procuring additional Voltage Support required from resources beyond their power factor ranges in real time; and~~

~~(f) Dispatching System Resources and Dispatchable Loads and increasing Generating Units' output to manage Intra-Zonal Congestion in real time using Energy Bids Dispatched out of sequence.~~

~~34.3.0.2 General Principles.~~

~~The ISO shall base real-time Dispatch of Generating Units, Curtailable Demands, Interconnection schedules, System Units, Loads and System Resources on the following principles:~~

~~(a) the ISO shall dispatch Generating Units, System Units, Dispatchable Interconnection schedules, and System Resources providing Regulation service to meet NERC and WECC Area Control Error (ACE) performance requirements;~~

~~(b) in each Dispatch Interval, following the loss of a resource and once ACE has returned to zero, the ISO shall determine whether the Regulation Generating Units, System Units, Dispatchable Interconnection schedules, and System Resources are operating at a point away from their preferred operating point and project the Imbalance Energy requirements based on the forecasted Demand for the next Dispatch Interval. The ISO shall then Dispatch Generating Units, System Units, Curtailable Demands, Dispatchable Interconnection schedules, and System Resources available (either providing Spinning Reserve, Non-Spinning Reserve, Replacement Reserve or offering Supplemental Energy) to meet the projected Imbalance Energy requirements for the next Dispatch Interval and return the Regulation Generating Units, System Units, Dispatchable Interconnection schedules, and System Resources to their preferred operating points to restore their full regulating margin;~~

~~(c) the ISO shall economically Dispatch Generating Units, System Units, Loads, Curtailable Demands, Dispatchable Interconnection schedules and System Resources only to meet its Imbalance Energy requirements and eliminate any Price Overlap between Energy Bids subject to resource and transmission system Constraints, thereby, Dispatching the relevant resources in real time for economic trades either between Scheduling Coordinators or within a Scheduling Coordinator's portfolio;~~

~~(d) subject to Section 34.3.0.3 and its subparts, the ISO shall select the Generating Units, System Units, Loads, Curtailable Demands, Dispatchable Interconnection schedules and System Resources to be dispatched in merit order according to their Energy Bids to meet its Imbalance Energy requirements and to eliminate any Price Overlap based on a constrained optimization method to minimize the overall cost of Imbalance Energy subject to resource and transmission system Constraints;~~

~~(e) subject to Section 34.3.0.3 and its subparts, the ISO shall not discriminate between Generating Units, System Units, Loads, Curtailable Demands, Dispatchable Interconnection schedules and System Resources other than based on price, and the effectiveness (e.g., location and ramp rate) of the resource concerned to respond to the fluctuation in Demand or Generation or to resolve Inter-Zonal Congestion;~~

~~(f) Generating Units, System Units, Loads, Curtailable Demands, Dispatchable Interconnection schedules and System Resources shall be dispatched during the operating hour only until the next variation in Demand or the end of the operating hour, whichever is sooner. In dispatching such resources, the ISO makes no further commitment as to the duration of their operation, nor the level of their output or Demand, except to the extent that a Dispatch instruction causes Energy to be delivered in a different Dispatch Interval. In Dispatching such resources, the ISO may make commitments beyond the current Settlement Period;~~

~~(g) The ISO will not differentiate between Ancillary Services procured by the ISO and Ancillary Services which are being self-provided;~~

~~(h) The operational ramp rate(s) of a resource will be considered by the RTD Software in determining the amount of Instructed Imbalance Energy by Dispatch Interval, and such consideration may result in Instructed Imbalance Energy in Dispatch Intervals prior to or subsequent to the Dispatch Interval to which the Dispatch Instruction applies;~~

~~(i) System Resources identified as Dispatchable within the operating hour pursuant to Section 34.2.1.1A shall be Dispatched optimally through the RTD Software. Such bids will be settled pursuant to Section 11.2.4.1.1.2;~~

~~(j) The ISO will pre-dispatch Energy Bids from System Resources, subject to Hourly Pre-Dispatch as indicated in Section 34.2.1.1A, prior to the beginning of each hour consistent with applicable WECC~~

~~interchange scheduling practices, assuring that any Price Overlap between such decremental and incremental Energy Bids will be eliminated. Such bids will be settled pursuant to Section 11.2.4.1.1.2.~~

~~(k) In issuing the Dispatch Instructions, the ISO will not intentionally request UDCs, Participating Generators, Generating Unit operators, Participating Transmission Owners, Control Area Operators (to the extent the agreement between the Control Area Operator and the ISO so provides), Metered Subsystem Operators or Scheduling Coordinators to exceed any inherent plant rating or local restriction imposed by the plant or transmission owner in order to protect the design and/or operational integrity of its plant or equipment. In issuing Dispatch Instructions to PTOs, the ISO will comply with Section 5.1.7 of the TCA. Any conflict that may arise between an ISO issued Dispatch Instruction and a plant or transmission owner's restriction as mentioned above must be immediately brought to the ISO's attention by the person receiving such Dispatch Instruction prior to any attempt to implement that Dispatch Instruction.~~

~~34.3.0.3 Ancillary Services Dispatch.~~

~~The ISO will base its standards for the Dispatch of Ancillary Services upon WECC, MORC, and ISO Controlled Grid reliability requirements. The ISO may Dispatch Generating Units, Loads, System Units and System Resources contracted to provide Ancillary Services (either procured through the ISO's competitive market, or self-provided by Scheduling Coordinators) to supply Imbalance Energy. During normal operating conditions, the ISO shall Dispatch the following resources to supply Imbalance Energy: (i) those Generating Units, Loads, System Units and System Resources having offered Supplemental Energy bids, (ii) those Generating Units, Loads, System Units and System Resources contracted to provide Replacement Reserve and (iii) those Generating Units, Loads, System Units and System Resources that have contracted to provide Spinning and Non-Spinning Reserve, except for those resources that have indicated that 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. In the event of an unplanned Outage, a Contingency or a threatened or actual System Emergency, the ISO may also Dispatch all other Generating Units, Loads, System Units and System Resources contracted to provide Spinning Reserve or Non-Spinning Reserve to supply Imbalance Energy. If a Generating Unit, Load, System Unit or System Resource, which is supplying~~

~~Operating Reserve, is Dispatched to provide Imbalance Energy, the ISO shall replace the Operating Reserve from the same or another resource within the time frame specified in the WECC guidelines.~~

~~34.3.0.3.1 Dispatch of Competitively Procured and Self-Provided Ancillary Services.~~

~~Generating Units and Loads selected in the ISO competitive auction or self-provided shall be Dispatched based on their Energy Bids as described in Section 34.3.0.1.2, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.3.0.3.~~

~~34.3.0.3.2 Dispatch of Self-Provided Ancillary Services.~~

~~Where a Scheduling Coordinator has chosen to self-provide the whole of the additional Operating Reserve required to cover any Interruptible Imports which it has scheduled and has identified specific Generating Units, Loads, System Units or System Resources as the providers of the additional Operating Reserve concerned, the ISO shall Dispatch only the designated Generating Units, Loads, System Units or System Resources in the event of the ISO being notified that the Interruptible Import is being curtailed. For all other Ancillary Services which are being self-provided the Energy Bid shall be used to determine the Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.3.0.3.~~

~~34.3.0.3.3 Ancillary Services Requirements for Real Time Dispatch.~~

~~The following requirements apply to the Dispatch of Ancillary Services in real time:~~

~~34.3.0.3.3.1 Regulation.~~

~~(a) Regulation provided from Generating Units or System Resources must meet the standards specified in this Tariff and the Part of A of Appendix K;~~

~~(b) the ISO will Dispatch Regulation in merit order of Energy bid prices as determined by the EMS;~~

~~(c) in the event of an unscheduled increase in system Demand or a shortfall in Generation output and Regulation margin drops below a predetermined value, the ISO will use scheduled Operating Reserve, Replacement Reserve or Supplemental Energy to restore Regulation margin; and~~

~~(d) when scheduled Operating Reserve is used for restoration of Regulation reserve, the ISO shall arrange for the replacement of that Operating Reserve (see Section 34.3.0.3.3.4);~~

~~34.3.0.3.3.2 Operating Reserve.~~

~~(a) Spinning Reserve:~~

~~(i) Spinning Reserve provided from Generating Units and Interconnection schedules must meet the standards specified in Part B of Appendix K;~~

~~(ii) the ISO will Dispatch Spinning Reserve as may be required to meet the Applicable Reliability Criteria;~~

~~(iii) the ISO may Dispatch Spinning Reserve as balancing Energy to return Regulation Generating Units to their Set Points and restore full Regulation margin; and~~

~~(iv) the ISO will Dispatch Spinning Reserve in merit order of Energy bid prices as determined by the RTD Software;~~

~~(b) Non-Spinning Reserve:~~

~~(i) Non-Spinning Reserve provided from Generating Units, Demands, and external imports of System Resources must meet the standards specified in Part C of Appendix K~~

~~(ii) the ISO may Dispatch Non-Spinning Reserve in place of Spinning Reserve to meet Applicable Reliability Criteria;~~

~~(iii) the ISO will Dispatch Non-Spinning Reserve in merit order of Energy bid prices as determined by the RTD Software; and~~

~~(iv) the ISO may Dispatch Non-Spinning Reserve to replace Spinning Reserve if there is a shortfall in Spinning Reserve because of a deficiency of balancing Energy;~~

~~34.3.0.3.3.3 Replacement Reserve.~~

~~(a) Replacement Reserve provided from Generating Units, Curtailable Demands and Interconnection schedules must meet the standards specified in Part D of Appendix K~~

~~(b) the ISO will utilize Replacement Reserve to replace Operating Reserve that has been Dispatched due to a shortfall in Generation or an increase in Demand;~~

~~(c) the ISO may Dispatch Replacement Reserve to replace Operating Reserve that has been Dispatched for balancing Energy; and~~

~~(d) the ISO will Dispatch Replacement Reserve in merit order of Energy Bid prices as determined by RTD;~~

~~34.3.0.3.3.5 Voltage Support.~~

~~(a) Voltage Support provided from Generating Units shall meet the standards specified in this Tariff and the Part E of Appendix K;~~

~~(b) the ISO may Dispatch Generating Units to increase or decrease MVar output within the power factor limits of 0.9 lagging to 0.95 leading (or within other limits specified by the ISO in any exemption granted pursuant to Section 8.2.3.4 of the ISO Tariff) at no cost to the ISO when required for System Reliability;~~

~~(c) may Dispatch each Generating Unit to increase or decrease MVar output outside of established power factor limits, but within the range of the Generating Unit's capability curve, at a price calculated in accordance with ISO Tariff;~~

~~(d) If Voltage Support is required in addition to that provided pursuant to 34.3.0.3.3.5 (b) and (c), the ISO will reduce output of Participating Generators certified in accordance with Appendix K . The ISO will select Participating Generators in the vicinity where such additional Voltage Support is required; and~~

~~(e) the ISO will monitor voltage levels at Interconnections to maintain them in accordance with the applicable Inter-Control Area Agreements.~~

34.3 Real-Time Dispatch.

The RTD can operate in three modes: RTED, RTCD and RTMD. The RTD (RTED and RTCD mode) uses a Security Constrained Economic Dispatch (SCED) algorithm every five minutes throughout the Trading Hour to determine optimal Dispatch Instructions to balance Supply and Demand and maintain required Ancillary Service quantities for the next binding target interval. The Real-Time Economic Dispatch (RTED) will be used under most circumstances and will optimally dispatch resources based on their Energy bids, excluding Contingency Only Operating Reserves except when needed to avoid an imminent System Emergency. The Real-Time Contingency Dispatch (RTCD) will be invoked when a transmission or generation contingency occurs and will include all Contingency Only Operating Reserves in the optimization. The Real Time Manual Dispatch (RTMD) will be invoked as a fall-back mechanism only when the RTED or RTCD fails to provide a feasible dispatch. These three modes of the RTD are described in Sections 34.3.1 to 34.3.3.

34.3.1 Real-Time Economic Dispatch.

RTED mode of operation for RTD normally runs every 5 minutes starting at approximately 7.5 minutes prior to the start of the next Dispatch Interval and produces a binding Dispatch Instruction for energy for the next Dispatch Interval and advisory Dispatch Instructions for as many as twelve future Dispatch Intervals over the RTD optimization Time-Horizon of 65 minutes. After being reviewed by CAISO Operator, only binding Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3. RTED will produce a Dispatch Interval LMP for each PNode for the Dispatch Interval associated with the binding Dispatch Instructions.

34.3.2 Real-Time Contingency Dispatch.

RTCD mode of operation for RTD is run in response to a significant Contingency event, such that waiting until the next normal RTD run is not adequate and/or Operating Reserve identified as Contingency Only need to be activated in response to the event. The CAISO Operator may activate the Operating Reserve identified as Contingency Only either on a resource specific basis or for all such resources. When activating Contingency Only reserves in RTCD, the original Energy Bids associated with the resources providing Operating Reserve will be used for the RTCD. RTCD uses SCED to produce an optimized set of binding Dispatch Instruction for a single 10 minute Dispatch Interval instead of a normal 5 minute Dispatch Interval. After being reviewed by CAISO Operator, only binding Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3. When activating a RTCD and returning to normal RTED run after a RTCD run, 5-minute Dispatch Interval LMPs will be produced for each PNode be based on the last available price from either the RTCD or normal RTED run relative to a 5-minute target Dispatch Interval.

34.3.3 Real-Time Manual Dispatch.

RTMD mode of operation for RTD is a merit-order run activated upon CAISO Operator request as a backup process in case the normal RTED process fails to converge. The RTMD run will provide the CAISO Operator a list of resources and quantity of MW available for dispatch in merit-order based on Operational Ramp-Rate but otherwise ignores transmission losses and network constraints. The CAISO Operator may Dispatch resources from the list by identifying the quantity of Imbalance Energy that is required for the System and/or directly selecting resources from the merit order taking into consideration actual operating conditions. After Dispatches have been selected, reviewed and accepted by CAISO Operator, Dispatch Instructions will be communicated in accordance with Section 6.3. While the RTMD mode is being used for Dispatch a uniform 5-minute MCP will be produced for all PNodes based on the merit order Dispatch. Until RTMD is actually run and RTMD-based Dispatch Instructions are issued after RTED fails to converge, all 5-minute Dispatch Interval LMPs will be set to the last LMP at each Node produced by the last RTED run that converged.

34.4 Short-Term Unit Commitment

At the top of each Trading Hour, immediately after the RTUC run is completed, the CAISO performs an approximately five (5) hour Short-Term Unit Commitment (STUC) run using SCUC and the CAISO Forecast of CAISO Demand to commit Medium Start Units and Short Start Units with Start-Up Times greater than the Time Horizon covered by the RTUC. The Time Horizon for the STUC optimization run will extend three hours beyond the Trading Hour for which the RTUC optimization was run, and will replicate the Bids used in that Trading Hour for these additional hours. The CAISO revises these replicated Bids each time the hourly STUC is run, to utilize the most recently submitted Bids. A Start-Up instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time as determined in the current STUC run in a subsequent RTUC or STUC run as a result of the Start-Up time of the resource. A Start-Up instruction produced by STUC is considered advisory if it is not binding, such that the resource could achieve its target start time as determined in the current RTUC run in a subsequent STUC or RTUC run based on its Start-Up Time. A binding Dispatch Instruction produced by STUC that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-up instruction by the CAISO Operator. The STUC will only decommit a resource to the extent that resource's physical characteristics allow it to be cycled in the same Time Horizon for which it was decommitted. STUC does not produce prices for Settlement.

34.5 General Dispatch Principles

The CAISO shall conduct all Dispatch activities consistent with the following principles:

(1) The CAISO shall issue AGC instructions electronically as often as every four seconds from its Energy Management System (EMS) to resources providing Regulation and on Automatic Generation Control to meet NERC and WECC performance requirements;

(2) In each run of the RTED or RTCD the objective will be to meet the projected Energy

requirements over the Time Horizon of that run, subject to transmission and resource operational constraints, taking into account the short term CAISO Forecast of CAISO Demand adjusted as necessary by the CAISO Operator to reflect scheduled changes to Interchange and non-Dispatchable resources in subsequent Dispatch Intervals;

(3) Dispatch Instructions will be based on Energy Bids for those resources that are capable of intra-hour adjustments and will be determined through the use of SCED except when the CAISO must utilize the RTMD;

(4) When dispatching Energy from awarded Ancillary Service capacity the CAISO will not differentiate between Ancillary Services procured by the CAISO and Ancillary Services that are Self-Scheduled;

(5) The Dispatch Instructions of a resource for a subsequent Dispatch Interval shall take as a point of reference the actual output obtained from either the State Estimator solution or the last valid telemetry measurement and the resources operational ramping capability;

(6) In determining the Dispatch Instructions for a target Dispatch Interval while at the same time achieving the objective to minimize Dispatch costs to meet the forecasted conditions of the entire Time Horizon, the Dispatch for the target Dispatch interval will be affected by: (a) Dispatch Instructions in prior intervals, (b) actual output of the resource, (c) forecasted conditions in subsequent Intervals within the Time Horizon of the optimization, and (d) operational constraints of the resource, such that a resource may be Dispatched in a direction for the immediate target Dispatch Interval that is different than the direction of change in Energy needs from the current Dispatch Interval to the next immediate Dispatch Interval;

(7) Through Start-Up instructions the CAISO may instruct resources to Start Up or Shut Down, or may reduce Load for Participating Loads, over the Time Horizon for the RTM based on submitted Bids, Start-Up Costs and Minimum Load Costs consistent with operating characteristics of the resources that the SCED is able to enforce. In making Start-Up or Shut-Down decisions in the RTM, the CAISO may factor in limitations on number of run hours or Start-Ups of a resource to avoid exhausting its maximum number of run hours or Start-Ups during periods other than peak loading conditions;

(8) The CAISO shall only Start-Up resources that can start within the Time Horizon used by the RTM optimization methodology;

(9) The RTM optimization may result in resources being Shut Down consistent with their Bids and operating characteristics provided that: (1) the resource does not need to be on-line to provide Energy, (2) the resource is able to Start-Up within the RTM optimization Time Horizon, (3) the Generating Unit is not providing Regulation or Spinning Reserve, and (4) Generating Units online providing Non-Spinning Reserve may be Shut Down if they can be brought up within 10 minutes as such resources are needed to be online to provide Non-Spinning Reserves; and

(10) for resources that are both providing Regulation and have submitted Energy Bids for the RTM, Dispatch Instructions will be based on the Regulation Ramp-Rate of the resource rather than the Operational Ramp-Rate.

~~34.3.1 Resource Constraints.~~

~~The RTD Software shall enforce the following resource physical constraints:~~

~~(a) Minimum and maximum operating resource limits. Outages and limitations due to transmission clearances shall be reflected in these limits. The more restrictive operating or regulating limit shall be used for resources providing Regulation so that the RTD Software shall not Dispatch them outside their regulating range.~~

~~(b) Forbidden Operating Regions. Resources can only be ramped through these regions. The RTD Software shall not Dispatch resources within their Forbidden Operating Regions unless at the maximum applicable ramp rate to clear the Forbidden Operating Region in consecutive Dispatch Intervals.~~

~~(c) Operational ramp rates and start-up times. The submitted operational ramp rate as provided for in Section 30.4.6 shall be used for all Dispatch Instructions. Each Energy Bid shall be Dispatched only up to the amount of Imbalance Energy that can be provided within the Dispatch Interval based on the applicable operational ramp rate. The Dispatch Instruction shall consider the relevant start-up time as provided for in Section 30.4.6, if the resource is off-line, the relevant ramp rate function, and any prior commitments such~~

~~as schedule changes across hours and previous Dispatch Instructions. The start-up time shall be determined from the start-up time function and when the resource was last shut down. The start-up time shall not apply if the corresponding resource is on-line or expected to start.~~

~~(d) Maximum number of daily start-ups. The RTD Software shall not cause a resource to exceed its daily maximum number of start-ups.~~

~~(e) Minimum up and down time. The RTD Software shall not start up off-line resources before their minimum down time expires and shall not shut down on-line resources before their minimum up time expires.~~

~~(f) Operating (Spinning and Non-Spinning) Reserve. The RTD Software shall Dispatch Spinning and Non-Spinning Reserve subject to the limitations set forth in Section 34.3.0.3.~~

~~(g) Hourly Pre-Dispatch. If Dispatched, each System Resource flagged for Hourly Pre-Dispatch in the next hour shall be Dispatched to operate at a constant level over the entire hour. The RTD Software shall perform the Hourly Pre-Dispatch for each hour once prior to the operating hour. Hourly Pre-Dispatched System Resources shall be Pre-Dispatched in merit order and shall not set the price. The Hourly Pre-Dispatch shall not subsequently be revised by the RTD Software.~~

34.6 ~~34.5~~ Dispatch Instructions for Generating Units and ~~Curtailable Demand~~Participating Load.

The CAISO may issue Dispatch Instructions covering:

(a) Ancillary Services;

(b) ~~Supplemental~~ Energy, which may be used for:

(i) Congestion ~~Management~~relief;

(ii) provision of Imbalance Energy; or

(iii) replacement of an Ancillary Service;

(c) agency operation of Generating Units, ~~Curtailable Demands~~Participating Loads or Interconnection schedules, for example:

(i) output or Demand that can be Dispatched to meet Applicable Reliability Criteria;

(ii) Generating Units that can be Dispatched for Black Start;

(iii) Generating Units that can be Dispatched to maintain governor control regardless of their Energy schedules; ~~or~~

(d) the operation of voltage control equipment applied on Generating Units as described in this CAISO Tariff; ~~or~~

(e) MSS Load following instructions provided to the CAISO, which the CAISO incorporates to create their Dispatch Instructions; or~~.~~

(f) necessary to respond to a System Emergency or imminent emergency.

34.7 ~~34.3.0.1.2~~ Utilization of the Energy Bids. The CAISO ~~will use~~ uses Energy Bids ~~to Dispatch Energy and Ancillary Services to procure balancing Energy for optimally~~ for the following purposes: ~~a)~~ (i) satisfying R~~r~~eal-T~~t~~ime Energy needs; (ii) ~~(b)~~ mitigating Congestion; (iii) ~~(c)~~maintaining aggregate Regulation reserve capability in Real-Time ~~allowing resources providing Regulation service to return to the preferred operating point within their regulating ranges~~; (iv) ~~(d)~~ allowing recovery of Operating Reserves utilized in R~~r~~eal-T~~t~~ime operations; ~~and~~ (v) ~~(e)~~ procuring Voltage Support required from resources beyond their power factor ranges in Real-Time; (vi) establishing LMPs; (vii) as the basis for Bid Cost Recovery; and (viii) to the extent a Real-Time Energy Bid Curve is submitted starting at minimum operating level for a Short-Start resource that is scheduled to be on-line, the RTM may Dispatch such a resource down to its minimum operating level and may issue a Shut-Down Instruction to the resource based on its Minimum Load Energy costs.

~~(f) Dispatching System Resources and Dispatchable Loads and increasing Generating Units' output to manage Congestion in real time using Energy Bids Dispatched out of sequence.~~

~~**34.3.2 Transmission System Constraints.**~~

~~RTD shall use a Zonal DC network model where all nodes within a Zone would be collapsed into a single equivalent "Zonal bus." The constraints using the Zonal network model shall be the following:~~

~~(a) Power balance constraint in each Zone. The system Imbalance Energy requirement shall~~

~~be calculated on a Zonal basis. The power balance constraints shall dictate an optimal Dispatch that would eliminate the Imbalance Energy requirement in all Zones, subject to (b) below.~~

~~(b) Inter-Zonal Interface constraints. These constraints shall limit the net active power flow on Inter-Zonal Interfaces at or below their transfer limits. For Inter-Zonal Interfaces between the ISO Control Area and another Control Area, inter-Zonal transfer capacity shall be reserved for awarded Ancillary Services from System Resources not already Dispatched.~~

~~34.3.2.1 Inter-Zonal Congestion.~~

~~If there is Inter-Zonal Congestion in real time, the ISO's RTD Software shall increase Generation and/or reduce Demand separately for each Zone to optimally Dispatch available resources to resolve the Congestion.~~

~~34.3.2.2 Selection of Generating Unit or Load to Increase Generation or Reduce Demand.~~

~~Where the ISO determines that it is necessary to increase Generation or reduce Demand in a Zone in order to relieve Inter-Zonal Congestion the ISO shall select in merit order, the Generating Unit within the Zone (or the Interconnection schedule in a Control Area adjacent to the Zone) with a non-zero capacity remaining to increment which has the lowest incremental bid price ($/MWh) or the Curtailable Demand located within the Zone (or the Interconnection schedule in a Control Area adjacent to the Zone) with a non-zero capacity remaining to reduce which has the lowest Demand reduction bid price.~~

~~34.3.2.3 Selection of Generating Unit to Reduce Generation.~~

~~Where the ISO determines that it is necessary to reduce Generation in a Zone in order to relieve Inter-Zonal Congestion, the ISO shall select in merit order the Generating Unit within the Zone with a non-zero capacity remaining to decrement which has the highest decremental bid price.~~

~~34.3.2.4 Inter-hour Dispatch of Resources Without Real-Time Energy Bids.~~

~~Real-time Dispatch Instructions shall be issued for each Dispatch Interval as needed to prescribe the ramp between a resource's Final Hour-Ahead Schedule in one hour to its Final Hour-Ahead Schedule in the immediately succeeding operating hour. Such Dispatch Instructions shall be based on the lesser of: (1) the applicable operational ramp rate as provided for in Section 30.4.6 and (2) the ramp rate associated with the Standard Ramp. The Dispatch Instructions for ramping of Generating Units without~~

~~real-time Energy Bids in both operating hours shall begin 10 minutes prior to the start of each operating hour and shall end no sooner than 10 minutes after and no later than 50 minutes after the start of each operating hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2.~~

~~34.3.2.5 Inter-hour Dispatch of Resources With Real-Time Energy Bids.~~

~~Real-time Dispatch Instructions associated with the ramp between a resource's Final Hour-Ahead Schedule in one hour to its Final Hour-Ahead Schedule in the immediately succeeding operating hour shall be determined optimally by the RTD Software if the ISO has bids for either or both relevant operating hours. For any operating hour(s) for which bids have been submitted Dispatch Instructions will be optimized such that the Dispatch Operating Point is within the bid range(s). For any operating hour without submitted bids Dispatch Instructions will be optimized such that the Dispatch Operating Point conforms to the schedule within the operating hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2. Energy delivered or consumed as a result of ISO Dispatch of a resource's Energy Bid in one operating hour to a Dispatch Operating Point such that the resource cannot return to its successive operating hour Final Hour-Ahead Schedule by the beginning of the next operating hour is Residual Energy and shall be settled as Instructed Imbalance Energy as provided for in Appendix N, Part D-1, Section 2.1.2 and also may be eligible for recovery of its applicable Energy Bid costs in accordance with Section 11.2.4.1.1.1. Similarly, Energy delivered or consumed as a result of ISO Dispatch of a resource's Energy Bid in a future operating hour to a Dispatch Operating Point different from its current operating hour Final Hour-Ahead Schedule prior to the end of the current operating hour is also considered Residual Energy and shall be settled as Instructed Imbalance Energy as provided for in Appendix N, Part D-1, Section 2.1.2 and also may be eligible for recovery of its applicable Energy Bid costs in accordance with Section 11.2.4.1.1.1. When Ramping Energy Deviation and Residual Energy coexist within a given Dispatch Interval, the~~

~~Ramping Energy Deviation shall be the portion of Instructed Imbalance Energy that is produced or consumed within the schedule-change band defined by the Final Hour-Ahead Schedules of the two consecutive Settlement Periods; the Residual Energy shall be the portion of Instructed Imbalance Energy that is produced or consumed outside the schedule-change band.~~

~~34.3.3 Inter-Zonal Congestion.~~

~~In the event of Inter-Zonal Congestion in real time, the ISO shall procure Imbalance Energy as described in Section 34.3.~~

~~34.3.4 Intra-Zonal Congestion.~~

~~Except as provided in Section 30.6.1, in the event of Intra-Zonal Congestion in real time, the ISO shall adjust resources in accordance with Sections 27.1.1.6.1 and 27.1.1.6.2.~~

~~34.3.5 Recovery of Operating Reserve.~~

~~If procured Operating Reserve is used to meet Imbalance Energy requirements, such Operating Reserve may be recovered by the ISO's replacing the associated Imbalance Energy through the Dispatch of other Energy Bids in merit order to allow the resources that were providing Energy from the procured Operating Reserve to return to their operating point before the provided the Energy from the Operating Reserves. Any additional real-time Operating Reserve needs may be met through unloaded capacity from RMR resources.~~

~~34.3.6 Dispatch Information and Instructions.~~

~~34.3.6.1 Dispatch Information To Be Supplied to the ISO.~~

~~34.3.6.2 Dispatch Information To Be Supplied by Scheduling Coordinator~~

~~Each Scheduling Coordinator shall be responsible for the scheduling and Dispatch of Generation and Demand in accordance with its Final Schedule. Each Scheduling Coordinator shall keep the ISO appraised of any change or potential change in the current status of all Generating Units, Interconnection schedules and Inter-Scheduling Coordinator Energy Trades. This will include any changes in Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of a Generating Unit. Each Scheduling Coordinator shall immediately pass to the ISO any information which it receives from a Generator which the Generator provides to the Scheduling Coordinator pursuant to~~

~~Section 34.5. Each Scheduling Coordinator shall immediately pass to the ISO any information it receives from a MSS Operator which the MSS Operator provides to the Scheduling Coordinator regarding any change or potential change in the current status of all Generating Units, System Units, Interconnection schedules and Inter-Scheduling Coordinator Energy Trades. This information includes any changes in MSS System Units and MSS Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of the System Unit or Generating Unit.~~

~~34.3.6.3 Dispatch Information To Be Supplied by UDCs.~~

~~Each UDC shall keep the ISO informed of any change or potential change in the status of its transmission lines and station equipment at the point of interconnection with the ISO Controlled Grid. Each UDC shall keep the ISO informed as to any event or circumstance in the UDC's service territory that could affect the reliability of the ISO Controlled Grid. This would include adverse weather conditions, fires, bomb threats, etc.~~

~~34.3.6.4 Dispatch Information To Be Supplied by PTOs.~~

~~Each PTO shall report any change or potential change in equipment status of the PTO's transmission assets turned over to the control of the ISO or in equipment that affects transmission assets turned over to the control of the ISO immediately to the ISO (this will include line and station equipment, line protection, Remedial Action Schemes and communication problems, etc.). Each PTO shall also keep the ISO immediately informed as to any change or potential change in the PTO's transmission system that could affect the reliability of the ISO Controlled Grid. This would include adverse weather conditions, fires, bomb threats, etc.~~

~~Each PTO shall schedule all Outages of its lines and station equipment which are under the Operational Control of the ISO in accordance with the appropriate procedures in Section 9.3. Each PTO shall coordinate any requests for or responses to Forced Outages on its transmission lines or station equipment which are under the Operational Control of the ISO directly with the appropriate ISO Control Center as defined in Section 7.2.4.1.~~

~~34.3.6.6 Dispatch Information To Be Supplied by Control Area Operators.~~

~~The ISO and each adjacent Control Area Operator shall keep each other informed of any change or potential change in the status of the Interconnection and any changes in the Interconnection's TTC. The ISO and each adjacent Control Area Operator shall keep each other informed of situations such as adverse weather conditions, fires, etc., that could affect the reliability of any Interconnection. Each Control Area Operator of the Control Areas in the California area, as defined by the WECC Regional Security Plan, shall keep the ISO informed of all information required by WECC for use by the Reliability Coordinator.~~

~~The ISO and each adjacent Control Area Operator shall follow all applicable NERC and WECC scheduling procedures. This will include checking the Interconnection schedules for the next Settlement Period prior to the start of the Energy ramp going into that hour. The ISO and each adjacent Control Area Operator shall check and agree on actual MWh net interchange after the hour for the previous Settlement Period. One Control Area shall change its actual number to reflect that of the other Control Area in accordance with WECC standard procedures.~~

~~The ISO and each adjacent Control Area Operator shall exchange MW, MVar, terminal and bus voltage data with each other on a four second update basis. MWh data for the previous hour shall be exchanged once per hour. All MW and MWh data for both the ISO Control Area and the adjacent Control Areas must originate from the same metering equipment. All provisions in Sections 4.6.1.1(i) and 4.6.1.1 (ii) refer to information and data obtained from metering used for Control Area operations and not metering used for billing and settlement.~~

34.3.7 ~~All Dispatch Instructions except those for the Dispatch of Regulation (which will be communicated by direct digital control signals to Generating Units and, for System Resources, through dedicated communication links which satisfy the ISO's standards for external imports of Regulation) will be communicated electronically, except that, at the ISO's discretion, Dispatch Instructions may be communicated by telephone, or fax. Except in the case of deteriorating system conditions or emergency, and except for instructions for the Dispatch of Regulation, the ISO will send all Dispatch Instructions to the Scheduling Coordinator for the Generating Unit, System Unit, Load or System Resource, which it wishes to Dispatch. The recipient Scheduling Coordinator shall ensure that the Dispatch Instruction is~~

~~communicated immediately to the operator of the Generating Unit, System Unit, external import of System Resources or Load concerned. If the ISO considers that there has been a failure at a particular point in time or inadequate response over a particular period of time by the Generating Units to the Dispatch Instruction, the ISO will notify the relevant Scheduling Coordinator. The ISO may, with the prior permission of the Scheduling Coordinator concerned, communicate with and give Dispatch Instructions to the operators of Generating Units, System Units, external imports of System Resources and Loads directly without having to communicate through their appointed Scheduling Coordinator. The ISO shall record the communications between the ISO and Scheduling Coordinators relating to Dispatch Instructions in a manner that permits auditing of the Dispatch Instructions, and of the response of Generating Units, System Units, external imports of System Resources and Loads to Dispatch Instructions. In situations of deteriorating system conditions or emergency, the ISO reserves the right to communicate directly with the Generator(s) as required to ensure System Reliability. The recipient of a Dispatch Instruction shall confirm the Dispatch Instruction. Dispatch Instructions communicated by the ISO either electronically or by fax shall be confirmed electronically in accordance with ISO procedures. Dispatch instructions communicated verbally shall be confirmed by repeating the Dispatch instructions to the ISO. The ISO Tariff and Protocols govern the content, issue, receipt, confirmation and recording of Dispatch Instructions.~~

34.8 Dispatch of Energy From Ancillary Services.

The CAISO may issue Dispatch Instructions to Participating Generators, Participating Loads, System Units and System Resources contracted to provide Ancillary Services (either procured through the CAISO Markets, Self-Provided by Scheduling Coordinators, or dispatched in accordance with the RMR Contract) for the Supply of Energy. During normal operating conditions, the CAISO shall Dispatch those Participating Generators, Participating Loads, System Units and System Resources that have contracted to provide Spinning and Non-Spinning Reserve, except for those reserves designated as Contingency Only, in conjunction with the normal Dispatch of Energy. Contingency Only reserves are Operating Reserve capacity that have been designated, either by the Scheduling Coordinator or the CAISO, as available to supply Energy in the Real-Time only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency. The CAISO may designate any reserve not previously identified as Contingency Only by Scheduling Coordinator as Contingency Only reserves, as necessary to maintain WECC MORC requirements. In the event of an unplanned Outage, a Contingency or a threatened or actual System Emergency, the CAISO may dispatch Contingency Only reserves. In such cases the Contingency Only reserves will be dispatched based on the original Energy Bids. If Contingency Only reserves are dispatched in response to a System Emergency that has occurred because the CAISO has run out of Economic Bids when no Contingency event has occurred, the RTED will Dispatch such Contingency Only reserves using Maximum Bid Prices as provided in Section 36.9.1 as the Energy Bids for such reserves and will set prices accordingly. If a Participating Generator, Participating Load, System Unit or System Resource that is supplying Operating Reserve is dispatched to provide Energy, the CAISO shall replace the Operating Reserve as necessary to maintain WECC MORC criteria. If the CAISO uses Operating Reserve to meet Real-Time Energy requirements, and if the CAISO needs Operating Reserves to satisfy MORC requirements the CAISO shall restore the Operating Reserves to the extent necessary to meet MORC requirements through either the procurement of additional Operating Reserve in the RTM or the Dispatch of other Energy Bids in SCED to allow the resources that were providing Energy from the Operating Reserve to return to their Dispatch Operating Point. The upper portion of the Energy Bid Curve for a resource providing Regulation Up or Operating Reserves shall be allocated to any RTM AS Awards in the following order from higher to lower capacity where applicable: (a) Regulation-Up; (b) Spinning Reserve; and (c) Non-Spinning Reserve. For resources providing Regulation-Up, the applicable upper regulating limit shall be used as the basis of allocation if it is lower than the upper portion of the energy curve. The remaining portion of the Energy Bid Curve, if there is any, shall constitute a Bid for RTM Energy.

~~34.4 Notification of Non-Compliance With A Dispatch Instruction.~~

~~In the event that, in carrying out the Dispatch Instruction, an unforeseen problem arises (relating to plant operations or equipment, personnel or the public safety), the recipient of the Dispatch Instruction must notify the ISO or, in the case of a Generator, the relevant Scheduling Coordinator immediately. The relevant Scheduling Coordinator shall notify the ISO of the problem immediately.~~

~~34.5 Dispatch Instructions for Generating Units and Curtailable Demand.~~

~~The ISO may issue Dispatch Instructions covering:~~

~~(a) Ancillary Services;~~

~~(b) Supplemental Energy, which may be used for:~~

~~(i) Congestion Management;~~

~~(iii) Generating Units that can be Dispatched to maintain governor control regardless of their Energy schedules; or~~

~~(d) the operation of voltage control equipment applied on Generating Units as described in this ISO Tariff.~~

34.9 Exceptional Dispatch.

The CAISO may perform Exceptional Dispatches for the circumstances described in this Section 34.9, which may require the issuance of forced Shut Downs or forced Start-Ups. The CAISO shall conduct all Exceptional Dispatches consistent with good utility practice. Dispatch Instructions issued pursuant to Exceptional Dispatches shall be entered manually by the Operator into the RTM optimization software so that they will be accounted for and included in the communication of Dispatch Instructions to Scheduling Coordinators. Exceptional Dispatches are not derived through the use of the RTM optimization software and are not used to establish the LMP at the applicable PNode. The CAISO will record the circumstances that have led to the Exceptional Dispatch. Imbalance Energy delivered or consumed pursuant to the various types of Exceptional Dispatch are settled according to the provisions in Section 11.

34.9.1 System Reliability Exceptional Dispatches.

The CAISO may manually dispatch Generation Units, System Units, Participating Loads, Dynamic System Resources, and Condition 2 RMR Units pursuant to Section 41.8, in addition to or instead of resources dispatched by RTM optimization software during a System Emergency, or to prevent an imminent System Emergency or a situation that threatens System Reliability and cannot be addressed by the RTM optimization and system modeling. To the extent possible, the CAISO shall utilize available and effective Bids from resources before Dispatching resources without Bids. To deal with any threats to System Reliability, the CAISO may also dispatch in the Real-Time Non-Dynamic System Resources that have not been or would not be selected by the RTM for Dispatch, but for which the relevant Scheduling Coordinator has submitted a Bid into the HASP.

34.9.2 Other Exceptional Dispatch.

The CAISO may also manually dispatch resources in addition to or instead of resources dispatched by the RTM optimization software to: (1) perform Ancillary Services testing; (2) perform pre-commercial operations testing for Generating Units; (3) mitigate for Overgeneration; (4) provide for Black Start; (5) provide for Voltage Support; (6) accommodate TOR or ETC Self-Schedule changes after the Market Close of the HASP; or (7) to reverse a commitment instruction issued through the IFM that is no longer optimal as determined through RUC.

34.10 Uneconomic Adjustments in the RTM.

All Self-Schedules are respected by the SCED and 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 Economic Bids for the RTM are exhausted, all Self-Schedules between the Minimum Load and the lowest energy level of the first Energy Bid point will be subject to uneconomic adjustments based on assigned scheduling priorities. Through this process, imports and exports may be reduced to zero, Demand may be reduced to zero, and Generation may be reduced to a lower operating (or Regulating) limit (or lower Regulating limit plus any qualified Regulation Down Award or Self-Provision of Ancillary Services, if applicable). Any schedules below the Minimum Load level are treated as fixed schedules and are not subject to uneconomic adjustments for Congestion management but may be subject to decommitment via an Exceptional Dispatch if necessary as a last resort to relieve Congestion that could not otherwise be managed.

34.10.1 Increasing Supply.

The scheduling priorities as defined in the RTM optimization to meet the need for increasing Supply as reflected from higher to lower priority are as follows:

a) Non-Participating Load reduction (slack);

b) Contingency-Only Operating Reserve if activated by Operator to provide Energy (as indicated by the Contingency flag and the Contingency condition);

c) Economic Bids submitted in the HASP or RTM.

34.10.2 Decreasing Supply.

The scheduling priorities as defined in the RTM optimization to meet the need for decreasing supply as reflected from higher to lower priority are as follows:

a) Non-Participating Load increase;

b) Reliability Must Run (RMR) Schedule (Day-Ahead manual pre-dispatch or Manual RMR Dispatches or Dispatches that are flagged as RMR Dispatches following the MPM-RRD process);

c) Transmission Ownership Right (TOR) Self-Schedule;

d) Existing Rights (ETC) Self-Schedule;

e) Regulatory Must Run and Regulatory Must Take (RMT) Self-Schedule;

f) Participating Load increase;

g) Day-Ahead Supply Schedule;

h) Self-Schedule submitted in HASP; and

i) Economic Bids submitted in the HASP or RTM.

These dispatch priorities as defined in the RTM optimization may be superseded by operator actions and procedures. The Dispatch priorities listed in Sections 34.10.1 and 34.10.2 shall be incorporated into a Business Practice Manual (BPM) and to the extent it is determined necessary to modify the order of dispatch priority the CAISO may do so via an update to the BPM.

~~**34.6 Response Required by Generators to ISO Dispatch Instructions.**~~

~~Generators must:~~

~~(a) comply with Dispatch Instructions immediately upon receipt and shall respond in accordance with Good Utility Practice;~~

~~(b) meet voltage criteria in accordance with the provisions specified in the ISO Tariff;~~

~~(c) meet the applicable operational ramp rates as provided for in Section 30.4.6 ;~~

~~(d) respond to Dispatch Instructions for Ancillary Services within the time periods required by this ISO Tariff except in a System Emergency, when Section 7.4 will apply; and (in the case of Generating Units providing Regulation) respond to electronic signals from the EMS; and~~

~~(e) respond to a Dispatch Instruction issued for the start-up or shut down of a Generating Unit, within the time frame stated in the Instruction.~~

34.11 Means of Dispatch Communication.

The CAISO dispatches Regulation by AGC to Participating Generators and, for Dynamic System Resources, through dedicated communication links that satisfy the CAISO's standards for external imports of Regulation. The CAISO communicates all other Dispatch Instructions electronically, except that, at the CAISO's discretion, the CAISO may communicate Dispatch Instructions by telephone, or facsimile. Scheduling Coordinators shall confirm the Dispatch Instructions that are communicated orally by repeating them the to CAISO employee providing the Dispatch Instruction. Except in the case of deteriorating system conditions or an actual or threatened System Emergency, and except for Dispatch Instructions for Regulation, the CAISO sends all Dispatch Instructions to the Scheduling Coordinator. The recipient Scheduling Coordinator shall immediately communicate the Dispatch Instruction to the operator of the resource. The CAISO may, with the prior permission of the applicable Scheduling Coordinator, communicate with and give Dispatch Instructions to the operators of the resource directly without having to communicate through their Scheduling Coordinator. The CAISO shall record the communications between the CAISO and Scheduling Coordinators relating to Dispatch Instructions in a manner that permits auditing of the Dispatch Instructions, and of the response of the resources, as applicable. In situations of deteriorating system conditions or System Emergency, the CAISO reserves the right to communicate directly with the resource(s) as required to ensure System Reliability. Scheduling Coordinators are required to advise the CAISO immediately if any change in resource availability that prevents the recipient of a Dispatch Instruction from performing in accordance with that Dispatch Instruction.

34.11.1 ~~34.6~~ Response Required by ~~Generators~~ Resources to CAISO Dispatch Instructions.

~~Generators~~ Resources must:

(a) unless otherwise stated in the Dispatch Instruction, comply with a Dispatch Instruction~~s~~ immediately upon receipt ~~and shall respond in accordance with Good Utility Practice~~;

(b) respond to all Dispatch Instructions in accordance with Good Utility Practice;

(c)~~(b)~~ meet voltage criteria in accordance with the provisions ~~specified~~ in the CAISO Tariff;

(d)~~(c)~~ meet any ~~the~~ applicable operational ramp rates ~~as provided for in Section 30.4.6~~ ;

(e)~~(d)~~ respond to Dispatch Instructions for Ancillary Services within the required time periods and ~~required~~ (in the case of Participating Generators providing Regulation) respond to AGC from the EMS; and ~~by this ISO Tariff except in a System Emergency, when Section 7.4 will apply; and (in the case of Generating Units providing Regulation) respond to electronic signals from the EMS; and~~

(f)~~(e)~~ if a time frame is stated in a Dispatch Instruction, respond to a Dispatch Instruction within the stated time frame.~~respond to a Dispatch Instruction issued for the start-up or shut down of a Generating Unit, within the time frame stated in the Instruction.~~

34.11.2 Failure to Conform to Dispatch Instructions. ~~34.4 Notification of Non-Compliance With A Dispatch Instruction.~~ In the event that, in carrying out the Dispatch Instruction, an unforeseen problem arises (relating to plant operations or equipment, personnel or the public safety), the recipient of the Dispatch Instruction must notify the CAISO or, in the case of a Generator, the relevant Scheduling Coordinator immediately. The relevant Scheduling Coordinator shall notify the CAISO of the problem immediately. If a resource is unavailable or incapable of responding to a Dispatch Instruction, or fails to respond to a Dispatch Instruction in accordance with its terms, the resource shall be considered to be non-conforming to the Dispatch Instruction unless the resource has notified the CAISO of an event that prevents it from performing its obligations within 30 minutes of the onset of such event through a SLIC log entry. Notification of non-compliance via the Automated Dispatch System (ADS) will not supplant nor serve as the official notification mechanism to the CAISO. If the resource is considered to be non-conforming as described above, the Scheduling Coordinator for the resource concerned shall be subject to Uninstructed Imbalance Energy as specified in Section 11.5.2 and Uninstructed Deviation Penalties as specified in Section 11.23. This applies whether any Ancillary Service concerned are contracted or self-provided. For a non-Dynamic System Resource Dispatch Instruction prior to the Trade Hour, the Scheduling Coordinator shall inform the CAISO of its ability to conform to a Dispatch Instruction via "ADS". A decline of such a Non-Dynamic System Resource for a Dispatch Instruction received at least 40 minutes prior to the Trading Hour will be subject to Uninstructed Deviation Penalties as specific in Section 11.23. A decline of such a Non-Dynamic System resource for a Dispatch Instruction received less than 40 minutes prior to the Trading Hour will not be subject to Uninstructed Deviation Penalties.

34.12 Metered Subsystems.

Scheduling Coordinators that represent MSSs may submit Bids for Supply of Energy to the RTM, irrespective of whether the MSS is a Load following MSS. All Bids submitted for generating resources within a MSS in the HASP for the RTM and all Dispatch Instructions shall be generating resource-specific. MSS Operators are responsible for following Dispatch Instructions. Load following MSS Operators shall provide the CAISO with an estimate of the number of MWs the applicable generating resource(s) will be generating over the next two-hour interval. For Load following MSSs, the MSS Operator will provide the CAISO with telemetry of the MSS response to the Load following instructions and the expected output for these resources in five-minute intervals for the upcoming 120 minutes. The State Estimator will estimate all MSS Load in Real-Time and will incorporate the information provided by the Load following MSS Operator in clearing the RTM and its Dispatch Instructions.

~~**34.8 Failure to Conform to Dispatch Instructions.**~~

~~All Scheduling Coordinators, Participating Generators, owners or operators of Curtailable Demands and operators of System Resources providing Ancillary Services (whether self-provided or procured by the ISO) or whose Supplemental Energy bids have been accepted by the ISO shall be obligated to respond or to secure response to the ISO's Dispatch Instructions in accordance with their terms, and to be available and capable of doing so, for the full duration of the Settlement Period. Dispatch Instructions will be deemed delivered and associated Energy will be settled as Instructed Imbalance Energy in accordance with Section 11.2.4.1.1. If a Generating Unit, Curtailable Demand or System Resource is unavailable or incapable of responding to a Dispatch Instruction, or fails to respond to a Dispatch~~

~~Instruction in accordance with its terms, the Generating Unit, Curtailable Demand or System Resource:~~

~~(a) shall be declared and labeled as non-conforming to the ISO's instructions unless it has notified the ISO of an event that prevents it from performing its obligations within 30 minutes of the onset of such event through a SLIC log entry. Notification of non-compliance via the Automated Dispatch System (ADS) will not supplant nor serve as the official notification mechanism to the ISO;~~

~~(b) cannot set the Dispatch Interval Ex Post Price pursuant to Section 34.9.2.3; and~~

~~(c) the Scheduling Coordinator for the Participating Generator, owner or operator of the Curtailable Demand or System Resource concerned shall have Uninstructed Imbalance Energy due to the difference between the Generating Unit's, Curtailable Demand's or System Resource's instructed and actual output (or Demand). The Uninstructed Imbalance Energy shall be subject to the settlement for Uninstructed Imbalance Energy in accordance with Section 11.2.4.1 and the Uninstructed Deviation Penalty in accordance with Section 11.2.4.1.2. This applies whether the Ancillary Services concerned are contracted or self-provided.~~

~~The ISO will develop additional mechanisms to deter Generating Units, Loads, Curtailable Demand and System Resources in the ISO or other Control Areas from failing: (i) to respond at a particular time (or failing to adequately respond over a particular period of time) to a Dispatch Instruction, or (ii) to perform according to Dispatch instructions. The additional mechanisms, for example, can include reduction in payments to Scheduling Coordinators, or suspension of the Scheduling Coordinator's Ancillary Services certificate for the Generating Unit, Curtailable Demand or System Resource concerned. The ISO may apply penalties, fines, economic consequences or the sanctions referred to in the preceding two sentences for any failure or inadequate response under Section 34.3.7 to the Scheduling Coordinator representing the Generator responsible for such failure or inadequate response (which may be appropriately weighted to reflect its seriousness) subject to any necessary FERC approval.~~

34.13 ~~34.1.2.1~~ Real-Time Bid Submission.

Bids submitted in HASP for all Generating Resources and Participating Load shall be ~~submitted for use~~ used in the Real-Time Market. 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 ~~real-time Hourly Pre-Dispatch Section 34.3.0.2(i) and the Real-Time Economic Dispatch up to sixty-two (62) minutes prior to the Operating Hour.~~ Resource Adequacy Resources required to offer their ~~Available Generation~~Resource Adequacy Capacity in accordance with Section 40~~.1.4~~ shall be required to submit Energy Bids for: (1) all such ~~of their Available Generation~~Resource Adequacy Capacity and (2) any Ancillary Services capacity awarded or self-provided in the Day-Ahead, ~~or Hour-Ahead Ancillary Services markets~~the HASP or RTM~~/RT Market~~. In the absence of submitted ~~bids~~Bids, ~~default~~ Generated Bids ~~bids~~ will be used for ~~resources~~ Resource Adequacy Resources required to offer their ~~Available Generation~~Resource Adequacy Capacity in accordance with Section 40~~.1.4~~. ~~Resources~~ Resource Adequacy Resources not required to offer their ~~Available Generation~~Resource Adequacy Capacity in accordance with Section 40~~.1.4~~ that were awarded or self-provided Ancillary Services capacity must submit an Energy Bid for no less than the amount of awarded or self-provided Ancillary Services capacity. ~~Resources~~ Resource Adequacy Resource not required to offer their ~~Available Generation~~Resource Adequacy Capacity in accordance with Section 40~~.1.4~~ may voluntarily submit Energy Bids. Submitted Energy Bids shall be subject to the ~~Damage Control~~ maximum and minimum Bid requirements ~~Bid Cap caps~~ and Mitigation Measures as set forth in Section 39. ~~.1 and to the Mitigation Measures set forth in Attachment A to Appendix P~~.

~~**34.9 Pricing Imbalance Energy.**~~

~~**34.9.1 General Principles.**~~

~~Instructed and Uninstructed Imbalance Energy shall be paid or charged the applicable Resource-Specific Settlement Interval Ex Post Price or the Zonal Settlement Interval Ex Post Price except for hourly pre-dispatched Instructed Imbalance Energy, which shall be settled as set forth in Appendix N, Part D, Section 2.1.2. These prices are determined using the Dispatch Interval Ex Post Prices. The Dispatch Interval Ex Post Prices shall be based on the bid of the marginal Generating Units, System Units, and Curtailable Demand dispatched by the ISO to increase or reduce Demand or Energy output in each Dispatch Interval as provided in Section 34.9.2.1.~~

~~The marginal bid is the highest bid that is accepted by the ISO's RTD Software for increased energy~~

~~Supply or the lowest bid that is accepted by the ISO's RTD Software for reduced energy Supply. In the event the lowest price decremental bid accepted by the ISO is greater and not equal to the highest priced incremental bid accepted, then the Dispatch Interval Ex-Post Price shall be equal to the highest incremental bid accepted when there is a non-negative Imbalance Energy system requirement and equal to the lowest accepted decremental bid when there is a negative Imbalance Energy requirement.~~

~~When an Inter-Zonal Interface is operated at the capacity of the interface (whether due to scheduled uses of the interface, or decreases in the capacity of the interface), the marginal incremental or decremental bid prices in some Zones may differ from one another. In such cases, the ISO will determine separate Ex Post Prices for the Zones.~~

~~The ISO will respond to the Dispatch instructions issued by the RTD Software to the extent practical in the time available and acting in accordance with Good Utility Practice. The ISO will record the reasons for any variation from the Dispatch instructions issued by the RTD Software.~~

~~34.9.2 Determining Ex Post Prices.~~

~~34.9.2.1 Dispatch Interval Ex Post Prices.~~

~~34.9.2.2 Computation.~~

~~For each Dispatch Interval, the ISO will compute updated supply and demand curves, using the Generating Units, System Units, and Curtailable Demand Dispatched according to the ISO's RTD Software during that time period to meet Imbalance Energy requirements and to eliminate any Price Overlap. The Dispatch Interval Ex Post Price is equal to the bid price of the marginal resource accepted by the ISO for Dispatch, subject to any limitation applicable under Section 34.9.2.1. In the event of Inter-Zonal Congestion, the ISO will determine separate Dispatch Interval Ex Post Prices for each Zone or groups of Zones on either side of the Congested interface.~~

~~34.9.2.3 Eligibility.~~

~~A resource constrained at an upper or lower operating limit, a boundary of a Forbidden Operating Region or dispatched for the maximum Energy deliverable based on its maximum applicable ramp rate cannot be marginal (i.e., it cannot move in a particular direction) and thus is not eligible to set the Dispatch Interval Ex Post Price. System Resources are not eligible to set the Dispatch Interval Ex Post Price. Constrained Output Generation that has the ability to be committed or shut off within the two-hour time horizon of the~~

~~Real Time Market will be eligible to set the Dispatch Interval Ex Post Price if any portion of its Energy is necessary to serve Demand.~~

~~**34.9.2.4 Hourly Ex Post Price.**~~

~~The Hourly Ex Post Price in a Settlement Period in each Zone will equal the absolute-value Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone, where the weights are the system total Instructed Imbalance Energy, except Regulation Energy, for the Dispatch Interval.If the ISO declares a System Emergency, e.g. during times of supply scarcity, and involuntary Load Shedding occurs during the real-time Dispatch, the ISO shall set the Hourly Ex Post Price at the Administrative Price.~~

~~**34.9.2.5 Price for Uninstructed Deviations for Participating Intermittent Resources.**~~

~~Deviations associated with each Participating Intermittent Resource in a Scheduling Coordinator's Zonal portfolio shall be settled as provided in Section 11.2.4.5.1 at the monthly weighted average Dispatch Interval Ex Post Price, where the weights are the quantities of Instructed Imbalance Energy associated with each Dispatch Interval Ex Post Price~~

34.14 ~~34.2.1.4B~~ Real~~ ~~-Time Operational Activities in the Hour Prior to the Settlement Period.

34.14.1 ~~34.2.1.6~~ Confirm Interchange Transaction Schedules (ITSs).

Also in the hour prior to the beginning of the Operating Hour ~~Settlement Period~~ the CAISO will:

(a) adjust interchange transaction schedules (ITSs) as required under Existing Contracts in accordance with the procedures in the CAISO Tariff for the management of Existing Contracts;

(b) adjust ITSs as required by changes in transfer capability of transmission paths occurring after ~~close~~ Market Close of the HASP ~~Hour-Ahead Market~~; and

(c) agree on ITS changes with adjacent Control Area Operators.

34.15 ~~34.3.0~~ Rules For Real-Time Dispatch of Imbalance Energy Resources.

34.15.1 ~~34.3.1~~ Resource Constraints.

The ~~RTD Software~~SCED shall enforce the following resource physical constraints:

(a) Minimum and maximum operating resource limits. Outages and limitations due to transmission clearances shall be reflected in these limits. The more restrictive operating or regulating limit shall be used for resources providing Regulation so that the ~~RTD Software~~ SCED shall not Dispatch them outside their regulating range.

(b) Forbidden Operating Regions. Resources can only be ramped through these regions. The ~~RTD Software~~SCED shall not Dispatch resources within their Forbidden Operating Regions unless at the maximum applicable ramp rate to clear the Forbidden Operating Region in consecutive Dispatch Intervals. Resources ramping through a Forbidden Operating Region shall not set LMP at its location and cannot provide Ancillary Services.

(c) Operational R~~r~~amp R~~r~~ates and S~~s~~tart-U~~u~~p times. The submitted O~~o~~perational R~~r~~amp R~~r~~ate ~~as provided for in Section 30.4.6~~ for resources that are not providing Regulation, and the submitted Regulation Ramp Rate for resources that are providing Regulation shall be used for all Dispatch Instructions. The Ramping Rate for Non-Dynamic System Resources cleared in the HASP will not be observed. Rather the ramp of the Non-Dynamic System Resource respect inter-Control Area ramping conventions established by WECC. Ramp Rates for Dynamic System Resources will be observed like Participating Generators in the RTD. Each Energy Bid shall be Dispatched only up to the amount of Imbalance Energy that can be provided within the Dispatch Interval based on the applicable O~~o~~perational R~~r~~amp R~~r~~ate or Regulation Ramp Rate. The Dispatch Instruction shall consider the relevant S~~s~~tart-U~~u~~p time as ~~provided for in Section 30.4.6~~, if the resource is off-line, the relevant R~~r~~amp R~~r~~ate function, and any prior commitments such as schedule changes across hours and previous Dispatch Instructions. The S~~s~~tart-U~~u~~p time shall be determined from the S~~s~~tart-U~~u~~p time function and when the resource was last shut down. The S~~s~~tart-U~~u~~p time shall not apply if the corresponding resource is on-line or expected to start.

(d) Maximum N~~n~~umber of D~~d~~aily S~~s~~tart-U~~u~~ps. The ~~RTD Software~~SCED shall not cause a resource to exceed its daily maximum number of start-ups.

(e) Minimum U~~u~~p and D~~d~~own time. The ~~RTD Software~~SCED shall not S~~s~~tart U~~u~~p off-line resources before their minimum down time expires and shall not S~~s~~hut D~~d~~own on-line resources before their minimum up time expires.

(f) Operating (Spinning and Non-Spinning) Reserve. The SCED ~~RTD Software~~ shall Dispatch Spinning and Non-Spinning Reserve subject to the limitations set forth in Section 34.16.3.~~0.3.~~

(g) Non-Dynamic System Resources. If Dispatched, each Non-Dynamic System Resource ~~System Resource~~ flagged for h~~H~~ourly p~~P~~re-d~~D~~ispatch in the next Trading ~~h~~Hour shall be Dispatched to operate at a constant level over the entire Trading H~~h~~our. The ~~RTD Software~~HASP shall perform the h~~H~~ourly p~~P~~re-d~~D~~ispatch for each Trading ~~h~~Hour once prior to the O~~o~~perating H~~h~~our. ~~Hourly Pre-Dispatched System Resources shall be Pre-Dispatched in merit order and shall not set the price.~~ The h~~H~~ourly ~~P~~pre-d~~D~~ispatch shall not subsequently be revised by the SCED ~~RTD Software~~ and the resulting HASP Intertie Schedules are financially binding and are settled pursuant to section 11.4.

(h) Daily Energy use limitation to the extent that energy limitation is expressed in a resource's Bid.

34.16 Ancillary Services in the Real-Time Market.

34.16.1 ~~34.1.3~~ Requirement to Submit Energy Bids For Awarded or Self-Provided Ancillary Services Capacity.

Scheduling Coordinators for resources that have been awarded or self-provide Regulation Up, Spinning Reserve, or Non-Spinning Reserve ~~or Replacement Reserve~~ capacity must submit an ~~Supplemental~~ Energy ~~bid~~ Bid for at least all the awarded or self-provided Ancillary Services capacity. ~~To the extent a Supplemental Energy bid is not so submitted for a gas-fired resource, the ISO shall calculate a Supplemental Energy bid in accordance with Section 40.1.8 and insert that bid into the real-time Imbalance Energy market. To the extent a Supplemental Energy bid is not so submitted for a non-gas-fired resource, the ISO shall insert a bid of $0/MWh into the real-time Imbalance Energy market.~~

34.16.2 ~~34.3.0.3.2~~ Dispatch of Self-Provided Ancillary Services.

Where a Scheduling Coordinator has chosen to self-provide the whole of the additional Operating Reserve required to cover any Interruptible Imports which it has scheduled and has identified specific

Generating Units, Participating Loads, System Units or System Resources as the providers of the additional Operating Reserve concerned, the CAISO shall Dispatch only the designated Generating Units, Participating Loads, System Units or System Resources in the event of the CAISO being notified that the On Demand Obligation ~~Interruptible Import~~ is being curtailed. For all other Ancillary Services which are being self-provided the Energy Bid shall be used to determine the Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section ~~34.3.0.3~~ 34.10.

34.16.3 ~~34.3.0.3.3~~ Ancillary Services Requirements for ~~Real Time~~ RTM Dispatch.

The following requirements apply to the Dispatch of Ancillary Services in ~~real time~~the RTM:

34.16.3.1 ~~34.3.0.3.3.1~~ Regulation.

(a) Regulation provided from Generating Units or System Resources must meet the standards specified in this Tariff and the Part of A of Appendix K;

(b) The CAISO will Dispatch Regulation in merit order of ~~Energy bid~~ Bid prices as determined by the EMS~~;~~. Dispatch of Regulation by EMS does not set the RTM LMP.

(c) in the event of an unscheduled increase in system Demand or a shortfall in Generation output and Regulation margin drops below a predetermined value, the CAISO will use Dispatch Energy in the RTM or Dispatch Operating Reserve~~scheduled Operating Reserve~~, ~~Replacement Reserve or Supplemental Energy~~ to restore Regulation margin; and

(d) when scheduled Operating Reserve is used for restoration of Regulation reserve, the CAISO shall arrange for the replacement of that Operating Reserve ~~(see Section 34.3.0.3.3.4)~~;

34.16.3.2 ~~34.3.0.3.3.2~~ Operating Reserve.

(a) Spinning Reserve:

(i) Spinning Reserve provided from Generating Units and Interconnection schedules must meet the standards specified in Part B of Appendix K;

(ii) the CAISO will Dispatch Spinning Reserve as may be required to meet the Applicable Reliability Criteria;

(iii) the CAISO may Dispatch Spinning Reserve as balancing Energy to return Regulation

Generating Units to their Set Points and restore full Regulation margin; and

(iv) the CAISO will Dispatch Spinning Reserve in merit order of Energy ~~bid~~ Bid prices as determined by the ~~RTD Software~~SCED;

(b) Non-Spinning Reserve:

(i) Non-Spinning Reserve provided from Generating Units, Demands, and external imports of System Resources must meet the standards specified in Part C of Appendix K

(ii) the CAISO may Dispatch Non-Spinning Reserve in place of Spinning Reserve to meet Applicable Reliability Criteria;

(iii) the CAISO will Dispatch Non-Spinning Reserve in merit order of Energy ~~bid~~ Bid prices as determined by the SCED ~~RTD Software~~; and

(iv) the CAISO may Dispatch Non-Spinning Reserve to replace Spinning Reserve if there is a shortfall in Spinning Reserve because of a deficiency of balancing Energy;

34.16.3.3 ~~34.3.0.3.3.4~~ Replacement of Operating Reserve.

~~(a) in the event of an un-forecasted increase in system Demand or a shortfall in Generation output, the ISO shall utilize Replacement Reserve to restore Operating Reserve;~~

(a) ~~(b)~~ if pre-arranged Operating Reserve is used to meet balancing Energy requirements, the CAISO may replace such Operating Reserve by Dispatch of additional balancing Energy available from ~~Supplemental~~ Energy ~~bids~~Bids submitted in the HASP for the RTM or procurement of additional reserves based on an economic optimization of a resource's RTM Ancillary Service B~~b~~id and its Energy Bid.;

(b) ~~(c)~~ any additional Operating Reserve needs may also be met the same way;

(c) ~~(d)~~ where the CAISO elects to rely upon ~~Supplemental~~ Energy ~~bids~~Bids, the CAISO shall select the resources with the lowest incremental Energy Bid price as established by ~~RTD~~ SCED; and

~~(e) if the ISO restores Operating Reserve through utilization of Replacement Reserve, the ISO is not required to replace the utilized Replacement Reserve;~~

34.16.3.4 ~~34.3.0.3.3.5~~ Voltage Support.

(a) Voltage Support provided from Generating Units shall meet the standards specified in this Tariff and the Part E of Appendix K;

(b) the ~~ISO~~ CAISO may Dispatch Generating Units to increase or decrease MVar output within the power factor limits of 0.9 lagging to 0.95 leading (or within other limits specified by the CAISO ~~ISO~~ in any exemption granted pursuant to Section 8.2.3.3 ~~8.2.3.4~~ of the CAISO ~~ISO~~ Tariff) at no cost to the CAISO ~~ISO~~ when required for System Reliability;

(c) may Dispatch each Generating Unit to increase or decrease MVar output outside of established power factor limits, but within the range of the Generating Unit's capability curve, at a price calculated in accordance with CAISO ~~ISO~~ Tariff;

(d) If Voltage Support is required in addition to that provided pursuant to ~~34.3.0.3.3.5~~34.16.3.4 (b) and (c), the CAISO ~~ISO~~ will reduce output of Participating Generators certified in accordance with Appendix K . The CAISO ~~ISO~~ will select Participating Generators in the vicinity where such additional Voltage Support is required; and

(e) the CAISO ~~ISO~~ will monitor voltage levels at Interconnections to maintain them in accordance with the applicable Inter-Control Area Agreements.

34.16.4 ~~34.3.2.5~~ Inter-hour Dispatch of Resources With Real-Time Energy Bids.

~~Real-time~~ Dispatch Instructions associated with the ramp between ~~a resource's~~the HASP Bid~~Final Hour-Ahead Schedule~~ in one hour to ~~its~~the ~~Final Hour-Ahead~~ HASP ~~Schedule~~ Bid in the immediately succeeding operating hour shall be determined optimally by the ~~RTD Software~~SCED if the CAISO has ~~bids~~ Bids for either or both relevant operating hours. For any ~~operating~~ Operating ~~hour~~Hour(s) for which ~~bids~~ Bids have been submitted Dispatch Instructions will be optimized such that the Dispatch Operating Point is within the ~~bid~~ Bid range(s). For any ~~o~~Operating ~~h~~Hour without submitted ~~bids~~ Bids, Dispatch Instructions will be optimized such that the Dispatch Operating Point conforms to the schedule within the ~~operating~~ Operating ~~h~~Hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2. Energy delivered or consumed as a result of CAISO Dispatch of a resource's Energy Bid in one ~~operating~~ Operating ~~h~~Hour to a Dispatch Operating Point such that the resource cannot return to its successive ~~operating~~ Operating ~~hour~~ Hour ~~Final Hour-Ahead~~ Schedule or to an infra-marginal operating point by the beginning of the next ~~operating~~ Operating ~~hour~~ Hour is Residual Energy and shall be settled as Instructed Imbalance Energy as provided for in Appendix N, Part D-1, Section 2.1.2 and also may be eligible for recovery of its applicable Energy Bid costs in accordance with Section ~~11.2.4.1.1.1~~11.8. Similarly, Energy delivered or consumed as a result of CAISO Dispatch of a resource's Energy Bid in a future O~~o~~perating H~~h~~our to a Dispatch Operating Point different from its current ~~operating hour Final Hour-Ahead~~ Operating Point ~~Schedule~~ prior to the end of the current ~~operating~~ Operating ~~hour~~ Hour is also considered Residual Energy and shall be settled as Instructed Imbalance Energy as provided for in Appendix N, Part D-1, Section 2.1.2 and also may be eligible for recovery of its applicable Energy Bid costs in accordance with Section 11.8. When Ramping Energy Deviation and Residual Energy coexist within a given Dispatch Interval, the Ramping Energy Deviation shall be the portion of Instructed Imbalance Energy that is produced or consumed within the schedule-change band defined by the ~~Final Hour-Ahead~~accepted HASP ~~Schedules~~ Bids of the two consecutive Settlement Periods; the Residual Imbalance Energy shall be the portion of Instructed Imbalance Energy that is produced or consumed outside the schedule-change band.

34.16.5 ~~34.3.2.4~~ Inter-hour Dispatch of Resources Without Real-Time Energy Bids.

~~Real-time~~ Dispatch Instructions shall be issued for each Dispatch Interval as needed to prescribe the ramp between a resource's ~~Final~~accepted ~~Hour-Ahead~~HASP ~~Schedule~~ Bid in one Trading Hour~~hour~~ to its ~~Final~~accepted ~~Hour-Ahead~~HASP ~~Schedule~~ Bid in the immediately succeeding ~~operating~~ Operating ~~hour~~Hour. Such Dispatch Instructions shall be based on the lesser of: (1) the applicable ~~operational~~ Operational ~~ramp~~ Ramp ~~rate~~ Rate as provided for in Section ~~30.4.6~~30.10 and (2) the ramp rate associated with the Standard Ramp. The Dispatch Instructions for ramping of Generating Units without ~~real~~Real-T~~t~~ime Energy Bids in both ~~operating~~ Operating ~~hours~~ Hours shall ramp the resource between hourly schedules symmetrically across hourly boundaries in 20 to 60 minutes assuming congestion can be resolve utilizing Economic Bids. The minimum 20-minute ramp is required for smooth hourly schedule changes and is consistent with inter-tie scheduling agreements between Control Areas. Resources with slower ramp rates would have longer ramps, and at the extreme, would ramp from the middle of an hour to the middle of the next hour. ~~begin 10 minutes prior to the start of each operating hour and shall end~~

~~no sooner than 10 minutes after and no later than 50 minutes after the start of each operating hour~~. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2.

34.17 ~~34.3.6~~ Dispatch Information and Instructions.

34.17.1 ~~34.3.6.1~~ Dispatch Information To Be Supplied ~~to~~ by the CAISO.

Communication of Dispatch information provided by the CAISO shall be in accordance with Section 6.3

34.17.2 ~~34.3.6.2~~ Dispatch Information To Be Supplied by Scheduling Coordinator

Each Scheduling Coordinator shall be responsible for the ~~scheduling~~ submission of Bids and Dispatch of Generation and Demand in accordance with its ~~Final~~ Day-Ahead Schedule. Each Scheduling Coordinator shall keep the CAISO ~~appraised~~ apprised of any change or potential change in the current status of all Generating Units, Interconnection schedules and Inter-~~Scheduling Coordinator~~SC ~~Energy~~ Trades. This will include any changes in Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of a Generating Unit. Each Scheduling Coordinator shall immediately pass to the CAISO any information which it receives from a Generator which the Generator provides to the Scheduling Coordinator pursuant to Section ~~34.5~~ 36.11.1. Each Scheduling Coordinator shall immediately pass to the CAISO any information it receives from a MSS Operator which the MSS Operator provides to the Scheduling Coordinator regarding any change or potential change in the current status of all Generating Units, System Units, Interconnection schedules and Inter-Scheduling Coordinator Energy Trades. This information includes any changes in MSS System Units and MSS Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of the System Unit or Generating Unit.

34.17.3 ~~34.3.6.3~~ Dispatch Information To Be Supplied by UDCs.

Each UDC shall keep the CAISO informed of any change or potential change in the status of its transmission lines and station equipment at the point of interconnection with the CAISO Controlled Grid. Each UDC shall keep the CAISO informed as to any event or circumstance in the UDC's service territory that could affect the reliability of the CAISO Controlled Grid. This would include adverse weather conditions, fires, bomb threats, etc.

34.17.4 ~~34.3.6.4~~ Dispatch Information To Be Supplied by PTOs.

Each PTO shall report any change or potential change in equipment status of the PTO's transmission assets turned over to the control of the ~~ISO~~ CAISO or in equipment that affects transmission assets turned over to the control of the CAISO ~~ISO~~ immediately to the CAISO ~~ISO~~ (this will include line and station equipment, line protection, Remedial Action Schemes and communication problems, etc.). Each PTO shall also keep the CAISO ~~ISO~~ immediately informed as to any change or potential change in the PTO's transmission system that could affect the reliability of the CAISO ~~ISO~~ Controlled Grid. This would include adverse weather conditions, fires, bomb threats, etc.

Each PTO shall schedule all Outages of its lines and station equipment which are under the Operational Control of the CAISO in accordance with the appropriate procedures in Section 9.3. Each PTO shall coordinate any requests for or responses to Forced Outages on its transmission lines or station equipment which are under the Operational Control of the CAISO ~~ISO~~ directly with the appropriate CAISO ~~ISO~~ Control Center as defined in Section ~~7.2.4.1~~7.1.

34.17.5 ~~34.3.6.6~~ Dispatch Information To Be Supplied by Control Area Operators.

The CAISO ~~ISO~~ and each adjacent Control Area Operator shall keep each other informed of any change or potential change in the status of the Interconnection and any changes in the Interconnection's TTC. The CAISO ~~ISO~~ and each adjacent Control Area Operator shall keep each other informed of situations such as adverse weather conditions, fires, etc., that could affect the reliability of any Interconnection. Each Control Area Operator of the Control Areas in the California area, as defined by the WECC Regional Security Plan, shall keep the CAISO ~~ISO~~ informed of all information required by WECC for use by the Reliability Coordinator.

The CAISO ~~ISO~~ and each adjacent Control Area Operator shall follow all applicable NERC and WECC scheduling procedures. This will include checking the Interconnection schedules for the next Settlement Period prior to the start of the Energy ramp going into that hour. The CAISO ~~ISO~~ and each adjacent Control Area Operator shall check and agree on actual MWh net interchange after the hour for the previous Settlement Period. One Control Area shall change its actual number to reflect that of the other Control Area in accordance with WECC standard procedures.

The CAISO ~~ISO~~ and each adjacent Control Area Operator shall exchange MW, MVar, terminal and bus voltage data with each other on a four second update basis. MWh data for the previous hour shall be exchanged once per hour. All MW and MWh data for both the CAISO ~~ISO~~ Control Area and the adjacent Control Areas must originate from the same metering equipment. All provisions in Sections 4.6.1.1(i) and 4.6.1.1 (ii) refer to information and data obtained from metering used for Control Area operations and not metering used for billing and settlement.

34.18 ~~34.7~~ Qualifying Facilities.

Where a Qualifying Facility ("QF") has entered into an agreement with a PTO before March 31, 1997 for the supply of Energy to the PTO (an "Existing Agreement"), the ~~ISO~~ CAISO will follow the instructions provided by the parties to the Existing Agreement regarding the provisions of the Existing Agreement in the performance of its functions relating to ~~Outage~~ outage ~~Coordination~~coordination, and not require a QF to take any action that would interfere with the QF's obligations under the Existing Agreement. Each QF will make reasonable efforts to comply with the ~~ISO's~~ CAISO's instructions during a System Emergency without penalty for failure to do so.

34.19 ~~34.9~~ Pricing Imbalance Energy.

34.19.1 ~~34.9.1~~ General Principles.

Instructed and Uninstructed Imbalance Energy shall be paid or charged the applicable Resource-Specific Settlement Interval ~~Ex Post Price~~LMP ~~or the Zonal Settlement Interval Ex Post Price~~ except for hourly pre-dispatched Instructed Imbalance Energy, which shall be settled as set forth in Appendix N, Part D, Section 2.1.2. These prices are determined using the Dispatch Interval ~~Ex Post Prices~~LMPs. The Dispatch Interval ~~Ex Post Prices~~LMPs shall be based on the ~~bid~~ Bid of the marginal Generating Units, System Units, and ~~Curtailable Demand~~Participating Loads dispatched by the ~~ISO~~ CAISO to increase or reduce Demand or Energy output in each Dispatch Interval as provided in Section 34.19.2.1.

~~The marginal bid is the highest bid that is accepted by the ISO's RTD Software for increased energy Supply or the lowest bid that is accepted by the ISO's RTD Software for reduced energy Supply. In the event the lowest price decremental bid accepted by the ISO is greater and not equal to the highest priced incremental bid accepted, then the Dispatch Interval Ex-Post Price shall be equal to the highest~~

~~incremental bid accepted when there is a non-negative Imbalance Energy system requirement and equal to the lowest accepted decremental bid when there is a negative Imbalance Energy requirement. When an Inter-Zonal Interface is operated at the capacity of the interface (whether due to scheduled uses of the interface, or decreases in the capacity of the interface), the marginal incremental or decremental bid prices in some Zones may differ from one another. In such cases, the ISO will determine separate Ex Post Prices for the Zones.~~The ~~ISO~~ CAISO will respond to the Dispatch ~~instructions~~ Instructions issued by the ~~RTD Software~~SCED to the extent practical in the time available and acting in accordance with Good Utility Practice. The ~~ISO~~ CAISO will record the reasons for any variation from the Dispatch ~~instructions~~ Instructions issued by the ~~RTD Software~~SCED.

34.19.2 ~~34.9.2~~ Determining ~~Ex Post Prices~~Real-Time LMPs.

34.19.2.1 ~~34.9.2.1~~ Dispatch Interval ~~Ex Post Prices~~Real-Time LMPs.

34.19.2.2 ~~34.9.2.2~~ Computation.

For each Dispatch Interval, the ~~ISO~~ CAISO will compute updated supply and demand curves, using the Generating Units, System Units, Dynamic System Resources and ~~Curtailable Demand~~ Participating Load Dispatched according to the CAISO's ~~RTD Software~~ SCED during that time period to meet Imbalance Energy requirements~~ and to eliminate any Price Overlap~~. The RTM transactions will be settled at the Dispatch Interval ~~Ex Post Price~~LMPs in accordance with Section 11.5. ~~is equal to the bid price of the marginal resource accepted by the ISO for Dispatch, subject to any limitation applicable under Section 34.9.2.1. In the event of Inter-Zonal Congestion, the ISO will determine separate Dispatch Interval Ex Post Prices for each Zone or groups of Zones on either side of the Congested interface.~~

34.19.2.3 ~~34.9.2.3~~ Eligibility to Set the Real-Time LMP.

All Generating Units, Participating Loads, Dynamic System Resources, System Units, or COGs subject to the provisions in Section 27.7, with Bids, including Default Energy Bids, that are unconstrained due to Ramp Rates or other temporal constraints are eligible to set the LMP, provided that the Generating Units, Participating Loads, Dynamic System Resources, or System Unit is Dispatched within its submitted Economic Bid range. If a resource is Dispatched beyond its Economic Bid range, the CAISO enforces a resource-specific constraint on the resource due to an RMR or Exceptional Dispatch, or the resource is ramping through a Forbidden Operating Region, the resource will not be eligible to set the LMP.

Resources identified as MSS Load following resources are not eligible to set the LMP. A resource constrained at an upper or lower operating limit, a boundary of a Forbidden Operating Region or dispatched ~~for the maximum Energy deliverable based on its maximum applicable~~for a quantity of Energy such that its full ramping capability is constraining the ability of the resource to be dispatched for additional Energy in target interval. ~~rate~~ cannot be marginal (i.e., it ~~cannot move in a particular direction~~is constrained by the ramping capability) and thus is not eligible to set the Dispatch Interval ~~Ex Post Price~~LMP. Non-Dynamic System Resources ~~System Resources~~ are not eligible to set the Dispatch Interval ~~Ex Post Price~~LMP. Dynamic System Resources are eligible to set the Dispatch Interval LMP. Constrained Output Generation that has the ability to be committed or shut off within the two-hour ~~time horizon~~Time Horizon of the ~~Real Time Market~~RTM will be eligible to set the Dispatch Interval ~~Ex Post Price~~LMP if any portion of its Energy is necessary to serve Demand. Dispatches of Regulation resources by EMS in response to AGC will not set the RTM LMP. Dispatches of Regulation resources Dispatch Operating Point by RTM SCED will be eligible to set the RTM LMP.

34.19.2.4 Real-Time LMP When Responding To A Contingency.

In cases when a Contingency occurs and the CAISO must activate its Operating Reserves, it may perform a Real-Time Contingency Dispatch (RTCD) for a target interval 10 minutes from the current time. When activating a Contingency Dispatch and returning to normal dispatch in RTM, LMPs shall be based on the last available price from either the Contingency Dispatch or normal Dispatch run relative to the 5 minute pricing target.

34.19.2.5 ~~34.9.2.5~~ Price for Uninstructed Deviations for Participating Intermittent Resources.

Deviations associated with each Participating Intermittent Resource in a Scheduling Coordinator's ~~Zonal~~ portfolio shall be settled as provided in Section 11.12 ~~11.2.4.5.1~~ at the monthly weighted average Dispatch Interval ~~Ex Post Price~~LMP, where the weights are the quantities of Instructed Imbalance Energy associated with each Dispatch Interval ~~Ex Post Price~~LMP.

35 [Not Used]

36 Congestion Revenue Rights

36.1 Overview of CRRs and Procurement of CRRs.

The CAISO distributes CRRs through an allocation and auction process as described in this Section. CRR Holders and Market Participants eligible to become CRR Holders can also buy, sell, or trade CRRs bilaterally and are required to register such changes in CRR holdings through the Secondary Registration System. CRRs are Day-Ahead instruments and provide their holders with a hedge against Congestion Charges from the Day-Ahead Market and not against Congestion Charges associated with HASP Intertie LMPs or Real-Time LMPs.

36.2 Types of CRR Instruments.

CRRs can be CRR Obligations or CRR Options. Each CRR is fully specified by its type (CRR Obligation or CRR Option), its CRR Source(s), its CRR Sink(s), its MW quantity, and the Trading Hours for which it is valid. The CRR Source(s) and CRR Sink(s) determine the direction of the CRR, which is from CRR Source(s) to CRR Sink(s).

36.2.1 CRR Obligations.

A CRR Obligation entitles its holder to receive a CRR Payment if the Congestion in a given Trading Hour is in the same direction as the CRR Obligation, and requires the CRR Holder to pay a CRR Obligation Charge if the Congestion in a given Trading Hour is in the opposite direction of the CRR. The CRR Payment or CRR Obligation Charge is equal to the per-MWh cost of Congestion (which equals the MCC at the CRR Sink minus the MCC at the CRR Source) multiplied by the MW quantity of the CRR. CRR Obligations are settled pursuant to Section 11.2.4.2.2.

36.2.2 CRR Options.

A CRR Option entitles its Holder to a CRR Payment if the Congestion is in the same direction as the CRR Option, but requires no CRR Obligation Charge if the Congestion is in the opposite direction of the CRR. The CRR Payment is equal to the per-MWh cost of Congestion (which equals the MCC at the CRR Sink minus the MCC at the CRR Source, when this quantity is positive and zero otherwise) multiplied by the MW quantity of the CRR. CRR Options are settled pursuant to Section 11.2.4.2.1.

36.2.3 Point-to-Point CRRs.

A Point-to-Point CRR is a CRR Option or CRR Obligation defined from a single CRR Source to a single CRR Sink.

36.2.4 Multi-Point CRRs.

A Multi-Point CRR ("MPT-CRR") is a CRR Obligation defined by more than one CRR Source and/or more than one CRR Sink, plus a specified distribution of the total MW value of the CRR over the multiple CRR Sources and/or multiple CRR Sinks such that the total MW assigned to all CRR Sources equals the total MW assigned to all CRR Sinks equals the MW value of the CRR.

36.3 CRR Specifications.

36.3.1 Quantity.

CRRs are distributed and settled in no less than one-tenth of a MW denomination.

36.3.2 Term.

CRRs are either monthly or seasonal in term. Seasonal CRRs are defined according to WECC standards for seasons.

36.3.3 On-Peak and Off-Peak Specifications.

CRRs are defined either for on-peak or off-peak hours as specified by the CAISO in the applicable Business Practice Manuals consistent with the WECC standards at the time of the relevant CRR Allocation or CRR Auction.

36.4 Available CRR Capacity.

When the CAISO conducts its CRR Allocation and CRR Auction, the CAISO shall use the most up-to-date DC FNM which is based on the AC FNM used in the Day-Ahead Market. The Seasonal Available CRR Capacity shall be based on: (i) the DC FNM, taking into consideration any long-term scheduled transmission outages, (ii) OTC adjusted for any long-term scheduled derates, and (iii) a downward adjustment due to TOR as determined by the CAISO. The Monthly Available CRR Capacity shall be based on: (i) the DC FNM, taking into consideration any scheduled transmission outages for that month and any new transmission facilities added to the CAISO Controlled Grid that were not part of the DC FNM used to determine the prior Seasonal Available CRR Capacity and that have already been placed in-service and energized at the time the CAISO starts the applicable monthly process, (ii) OTC adjusted for any scheduled derates for that month, and (iii) a downward adjustment due to TOR as determined by the CAISO.

36.4.1 Transmission Capacity Available for CRR Allocation and CRR Auction. The CAISO makes available seventy-five percent (75%) of Seasonal Available CRR Capacity for the annual CRR Allocation and CRR Auction processes, and one hundred percent (100%) of Monthly Available CRR Capacity for the monthly CRR Allocation and CRR Auction processes. Available Capacity at Scheduling Points shall be determined in accordance with Section 36.8.4.1 for the purposes of CRR Allocation and CRR Auction of CRRs that have a CRR Source identified at a Scheduling Point. Before commencing with the annual or monthly CRR Allocation and Auction processes, the CAISO may distribute any CRRs to sponsors of merchant transmission projects in accordance with Section 36.11 and will model those as fixed CRRs on the DC FNM to be used in the allocation and auction.

36.4.2 Simultaneous Feasibility. The annual and monthly CRR Allocation processes release CRRs to fulfill CRR nominations as fully as possible subject to a Simultaneous Feasibility Test ("SFT"). To the extent that nominations are not simultaneously feasible, the nominations are reduced in accordance with the CRR Allocation optimization formulation until simultaneous feasibility is achieved. The CRR Allocation optimization formulation, detailed in the Business Practice Manuals, reduces allocated CRRs based on effectiveness in relieving overloaded constraints in order to minimize the total MW volume reduction of nominations while achieving simultaneous feasibility. The SFT for each CRR Allocation considers:

a CRRs representing ETCs, Converted ETCs and any TOR capacity that was not captured in the adjustments described in Section 36.4, which the CAISO deems necessary to prevent the congestion settlement of ETCs, Converted ETCs, and TORs from causing revenue inadequacy of allocated and auctioned CRRs;

b. In the case of the monthly CRR Allocation, the CRRs already released for that month in the annual allocation and auction; and,

c. The CRRs allocated in previous allocation tiers as described in Sections 36.8.3.1 through 36.8.3.6.

In the event that transmission outages and derates modeled for the monthly CRR Allocation and CRR Auction render previously issued Seasonal CRRs infeasible, the CAISO will increase the transfer capacity on the overloaded facilities just enough to render all Seasonal CRRs issued for the month feasible without creating any additional capacity beyond what is needed for the feasibility of the Seasonal CRRs. The CAISO will announce these adjustments to the market prior to conducting the monthly CRR Allocation and CRR Auction so that Candidate CRR Holders can take these facts into consideration in preparing their nominations and bids.

36.5 CRR Holder Requirements.

Any entity that holds or intends to hold CRRs must register and qualify with the CAISO and comply with the other terms of this Section, regardless of whether they acquire CRRs by allocation, auction, or the secondary market.

36.5.1 Creditworthiness Requirements.

All CRR Holders and Candidate CRR Holders must comply fully with all Creditworthiness requirements as provided in Section 12 of the Tariff and as further developed in the applicable Business Practice Manuals.

36.5.2 Required Training.

CRR Holders and Candidate CRR Holders must attend a training class at least once prior to participating in the CRR Allocations or CRR Auctions. The CAISO may update training requirements annually or on an as-needed basis.

36.6 [NOT USED]

36.7 Bilateral CRR Transactions

36.7.1 Transfer of CRRs.

A CRR Holder may assign, sell, or otherwise transfer CRRs in increments of at least a tenth of a MW. Transfers must be for at least a full day term consistent with the on-peak or off-peak specification of the CRR. The transferee may be any entity eligible to be a CRR Holder consistent with this Tariff and the applicable Business Practice Manuals. All CRRs that are so assigned, sold, or otherwise transferred by the CRR Holder continue to be subject to the relevant terms and conditions set forth in the CAISO Tariff and the applicable Business Practice Manuals.

36.7.2 Responsibility of the CAISO.

The CAISO provides Market Participants a Secondary Registration System to facilitate and track CRR bilateral transactions. The Secondary Registration System automatically posts on the CAISO Website the bilateral transactions entered by Market Participants. The bulletin board of the Secondary Registration System enables any entity that wishes to purchase or sell CRRs to post that information.

36.7.3 CRR Holder Reporting Requirement.

CRR Holders must report to the CAISO by way of the Secondary Registration System all bilateral CRR transactions consistent with the terms of this Tariff and the Business Practice Manuals. Both the transferor and the transferee of the CRRs must register the transfer of the CRR with the CAISO using the Secondary Registration System at least five (5) business days prior to the effective date of transfer of revenues associated with a CRR. The CAISO shall not transfer any Settlement related to any CRR until such time that the CRR transfer has been successfully recorded through the SRS and the transferee has met all the creditworthiness requirements as specified in section 12. Both the transferor and transferee shall submit the following information to the Secondary Registration System: (i) the effective start and end dates of the transfer of the CRR; (ii) the identity of the transferor; (iii) the identity of the transferee; (iv) the quantity of CRRs being transferred; (v) the CRR Sources and CRR Sinks of the CRRs being transferred; and (vi) time of use period of the CRR. The transferee must meet all requirements of CRR Holders, including disclosure to the CAISO of all entities with which the transferee is affiliated that are CRR Holders or Market Participants as defined in Section 36.5.

36.8 CRR Allocation to Load Serving Entities for Internal Load.

The CAISO allocates CRRs to Load Serving Entities serving load internal to CAISO Control Area (including MSS entities as described in Section 36.10). All CRRs allocated under the terms of this Section 3.8 will be CRR Obligations.

36.8.1 Structure of the Allocation Process.

The CAISO conducts an annual CRR Allocation once a year for the entire year. The annual CRR Allocation releases Seasonal CRRs for four seasonal periods. The CAISO also conducts monthly CRR Allocations twelve times a year in advance of each month. Within each annual and monthly CRR Allocation process the CAISO performs distinct allocation processes for each on-peak and off-peak specification. The CRR Allocation process for CRR Year One is a distinct process that differs from subsequent annual CRR Allocations as described in Section 36.8.3.1 and 36.8.3.2. Each allocation procedure is based on nominations to the CAISO by LSEs eligible to receive CRRs. A timeline of the CRR Allocation and CRR Auction processes is contained in the BPMs.

36.8.2 Quantity of Load Eligible for CRRs.

An LSE serving internal Load is eligible for CRRs up to its Seasonal or Monthly CRR Eligible Quantity, which is derived from its Seasonal or Monthly CRR Load Metric as follows. These quantities are calculated for each LSE separately for each combination of season and time of use period for the annual process, and for each time of use period for each monthly process, and for each LAP within which the LSE serves Load. MSS eligibility for CRRs will account for net or gross MSS settlement in accordance with Section 4.9.13.1.

36.8.2.1 Seasonal CRR Eligible Quantity.

The CAISO constructs load duration curves for the annual CRR Allocation process for each LSE based on the LSE's submission to the CAISO of its historical hourly Load data for the prior year, for each LAP within which the LSE serves Load. An LSE's Seasonal CRR Load Metric for each season and time of use period is the MW level of Load that is exceeded only in 0.5% of the hours based on the LSE's historical Load data. In the event that the LSE has lost or gained net Load through Load migration during the course of the prior year, the historical load data will be adjusted to reflect the loss or gain in accordance with the applicable BPM. The CAISO calculates an LSE's Seasonal CRR Eligible Quantity by subtracting from that LSE's Seasonal CRR Load Metric the quantity of Load served by its TORs, ETCs, and Converted ETCs, and multiplying the result by 0.75.

36.8.2.2 Monthly CRR Eligible Quantity.

Each month the CAISO uses the LSE's submitted monthly load forecast to calculate two load duration curves (one on-peak and one off-peak load duration curve for the applicable month) to form the basis for monthly allocations for each LAP in which the LSE serves Load. The Monthly CRR Load Metric is the MW level of Load that is exceeded only in 0.5% of the hours based on the LSE's submitted load forecast. The CAISO will calculate an LSE's Monthly CRR Eligible Quantity by subtracting from that LSE's Monthly CRR Load Metric the quantity of Load served by its TORs, ETCs, and Converted ETCs.

36.8.3 CRR Allocation Process.

36.8.3.1 Annual CRR Allocation for CRR Year One.

The annual CRR Allocation for CRR Year One consists of a sequence of three (3) tiers for each season and time of use period (on-peak and off-peak). Each tier will feature a SFT applied to the CRR nominations submitted by eligible LSEs, the results of which are provided by the CAISO to the respective LSEs prior to the LSEs submitting their nominations to the next tier. Allocations of CRRs in each tier are considered final once they are provided by the CAISO to the respective LSEs. After each tier, LSEs will have an amount of time as specified in the Business Practice Manual after their receipt of the results of each tier to submit their nominations for the next tier, if there is one. The annual CRR Allocation allows LSEs to submit nominations up to their CRR Eligible Quantities for each season of the relevant year, each time of use period and each LAP. The annual CRR Allocation for CRR Year One will be conducted as follows:

a. **Tier 1.** In Tier 1, LSEs may nominate and the CAISO will allocate to the LSEs Seasonal CRRs up to 50% of their Seasonal CRR Eligible Quantity for each season.

b. **Tier 2.** In Tier 2, LSEs may nominate and the CAISO will allocate to the LSEs Seasonal CRRs up to 75% of their Seasonal CRR Eligible Quantity for each season minus the quantity of CRRs allocated to that LSE in Tier 1.

c. **Tier 3.** In Tier 3, LSEs may nominate and the CAISO will allocate to the LSEs Seasonal CRRs up to 100% of their Seasonal CRR Eligible Quantity for each season minus the quantity of CRRs allocated to that LSE in Tiers 1 and 2. In Tier 3, Sub-LAPs will be eligible CRR Sinks provided that the sub-LAP is within the nominating LSE's LAP.

36.8.3.2 Monthly Allocation for CRR Year One.

The monthly CRR Allocation in CRR Year One shall consist of a sequence of two (2) tiers for each time of use period (on-peak and off-peak). The monthly CRR Allocation will distribute Monthly CRRs to each LSE up to one hundred percent (100%) of its Monthly CRR Eligible Quantity minus CRRs allocated to that LSE in the annual CRR Allocation for the relevant month and time of use period. The monthly CRR Allocation for CRR Year One will be conducted as follows:

a. **Tier 1.** In Tier 1 of the monthly CRR Allocations, LSEs may nominate and the CAISO will allocate to the LSEs Monthly CRRs up to 50% of their Monthly CRR Eligible Quantities;

b. **Tier 2.** In Tier 2 of the monthly CRR Allocations, LSEs may nominate and the CAISO will allocate to the LSEs Monthly CRRs up to 100% of their CRR Eligible Quantities, minus the quantity of CRRs allocated to that LSE in Tier 1. In Tier 2 of the Monthly Allocation, sub-LAPs will be eligible CRR Sinks provided that the sub-LAP is within the nominating LSE's LAP.

36.8.3.4 Source Verification.

In CRR Year One, nominations for Tier 1 and Tier 2 of the annual CRR Allocation and Tier 1 of the monthly CRR Allocations must be source verified. Through the source verification process described in the Business Practice Manuals, an LSE must demonstrate that it could actually Schedule Energy from the nominated CRR Sources to serve its Load either through ownership of, or contractual rights to, the relevant Generating Units, or a contract to take ownership of power at the relevant source such as a Trading Hub or a Scheduling Point. Source verification will use data for the period beginning September 1, 2004 and ending August 31, 2005 as the basis for verification. Nominations of CRRs whose CRR Source is a Scheduling Point must be source verified in accordance with Section 36.8.4.1.

36.8.3.5 Annual CRR Allocation Beyond CRR Year One.

The annual CRR Allocation for years beyond CRR Year One consists of a sequence of three (3) tiers for each season and time of use period (on-peak and off-peak). Allocations of CRRs in each tier are considered final once they are provided by the CAISO to the respective LSEs. After each tier, LSEs will have an amount of time as specified in the Business Practice Manual after their receipt of the results of each tier to submit their nominations for the next tier, if there is one. The annual CRR Allocation will allow LSEs to submit nominations up to their Seasonal CRR Eligible Quantities for each season of the relevant year, each time of use period and each LAP in which they serve Load. Annual CRR Allocations for years beyond CRR Year One will be allocated as follows:

a. **Tier 1 – Priority Nomination Process.** Tier 1 of the annual CRR Allocation in years beyond CRR Year One will be a Priority Nomination Process ("PNP") through which CRR Holders may nominate some of the same CRRs that they were allocated in the immediately previous year. In the first Annual CRR Allocation after CRR Year One, an LSE may make PNP nominations up to the lesser of: (1) 33% of its Seasonal CRR Eligible Quantity for each season, time of use period and LAP for that year; or, (2) the total quantity of CRRs allocated to that LSE in the previous annual CRR Allocation for that season, time of use period and LAP, minus any reduction for net loss of Load through retail Load migration as described in Section 36.8.5.1. In the second and all subsequent Annual CRR Allocations beyond CRR Year One, an LSE may make PNP nominations up to the lesser of: (1) 66% of its Seasonal CRR Eligible Quantity for each season, time of use period and LAP for that year; or, (2) the total quantity of CRRs allocated to that LSE in the previous annual CRR Allocation for each season, time of use period and LAP minus any reduction for net loss of Load through retail Load migration. In addition, an LSE's nomination of any particular CRR source-sink combination in the PNP may not exceed the MW quantity of CRRs having that source and sink that the LSE was allocated in the previous annual CRR allocation for the same season and time of use period, adjusted for net Load loss resulting from Load migration. CRRs whose CRR Sink is a sub-LAP are not eligible for nomination in the PNP. PNP Eligible Quantities are not affected by secondary transfers of CRRs. That is: (i) a LSE may nominate in the PNP a CRR it was allocated in the prior annual CRR Allocation even though it transferred that CRR to another party during the year, and (ii) a LSE may not nominate in the PNP a CRR that it received through a secondary transfer from another party. CRRs received through a CRR Auction are not eligible for nomination in the PNP. The CAISO does not guarantee that all CRR nominations in the PNP will be allocated. The CAISO will conduct a SFT to determine whether all CRR nominations in the PNP are simultaneously feasible. If the SFT determines that all priority nominations are not simultaneously feasible, the CAISO will reduce the allocated CRRs until simultaneous feasibility is achieved.

b. **Tier 2.** In Tier 2 of the annual CRR Allocation, the CAISO will allocate Seasonal CRRs to each LSE up to 50% of its Seasonal CRR Eligible Quantity for each season, time of use period and LAP, plus 50% of the net load gained by the LSE through Load migration during the year, minus the quantity of CRRs allocated to that LSE in Tier 1.

c. **Tier 3.** In Tier 3 of the annual CRR Allocation, the CAISO will allocate Seasonal CRRs to each LSE up to 100% of its Seasonal CRR Eligible Quantity for each season, time of use period and LAP, minus the quantity of CRRs allocated to that LSE in Tiers 1 and 2. In Tier 3 of the annual CRR Allocation, sub-LAPs will be eligible CRR Sinks provided that the sub-LAP is within the nominating LSE's LAP.

36.8.3.6 Monthly Allocation Beyond CRR Year One.

The monthly CRR Allocation shall consist of a sequence of two (2) tiers of allocations for each time of use period (on-peak and off-peak). The monthly CRR Allocation will distribute Monthly CRRs to LSEs up to one hundred percent (100%) of their Monthly CRR Eligible Quantity minus CRRs allocated to that LSE in the annual CRR Allocation.

a. **Tier 1.** In Tier 1 of the monthly CRR Allocations, each LSE may nominate Monthly CRRs up to 50% of its Monthly CRR Eligible Quantities;

b. **Tier 2.** In Tier 2 of the monthly CRR Allocations, each LSE may nominate Monthly CRRs up to 100% of its Monthly CRR Eligible Quantities, minus the quantity of CRRs allocated to that LSE in Tier 1. In Tier 2 of the Monthly Allocation, Sub-LAPs will be eligible CRR Sinks.

36.8.4 Eligible Sources and Sinks for CRR Allocation.

Sources for CRR nominations in the annual and monthly CRR Allocation processes can be either PNodes or Trading Hubs. Sinks for CRR nominations in the annual and monthly CRR Allocation processes can be either LAPs, or sub-LAPs to the extent permissible under Section 36.8.3, or MSS-LAPs for those MSS that elect net settlement per Section 11.2.3.2. For Tiers 1 and 2 of the annual CRR Allocation in CRR Year One, LSEs requesting CRRs whose CRR Source is a specific Generating Unit will be limited to seventy-five percent (75%) of that Generating Unit's PMax, even if that Generating Unit is owned by or fully contracted to the LSE requesting the CRR. For Tiers 1 and 2 of the annual CRR Allocation in CRR Year One, LSEs requesting CRRs whose CRR Source is a Trading Hub will be limited to seventy-five percent (75%) of the average hourly quantity of Energy contracted for delivery at that Trading Hub. A

Scheduling Point can be a CRR Source for the annual and monthly CRR Allocation to the extent the requirements of Section 36.8.4.1 are satisfied.

36.8.4.1 Import CRRs.

LSEs may nominate CRRs whose CRR Source is a Scheduling Point in the annual and monthly CRR Allocation in accordance with this Section. In CRR Year One, in Tiers 1 and 2 of the annual CRR allocation process an LSE may nominate such CRRs to the extent that it can demonstrate to the CAISO that, for the verification period stated in Section 36.8.3.5, it owned or was a party to a contract with a System Resource, and that it or the counter-party to the contract had procured appropriate transmission from the applicable transmission provider outside the CAISO to the Scheduling Point. In addition, also in Tiers 1 and 2 of the annual CRR allocation in CRR Year One, all LSEs eligible to nominate CRRs under this Section 36.8 may nominate as CRR Sources, without any verification, shares of the residual import CRR capacity at each Scheduling Point that remains after the completion of the source verification process. Each LSE's share of the residual import CRR capacity will be calculated as follows. Starting with the total capacity at each Scheduling Point that was available in the DC FNM for the Annual CRR Allocation and Auction process, the CAISO will calculate the amount that remains at each Scheduling Point after subtracting the capacity accounted for by those Scheduling Point CRR Sources submitted by LSEs for verification that have been verified. The CAISO will then set aside 50 percent of this amount at each Scheduling Point for the Annual CRR Auction, and will allow LSEs to nominate pro rata shares of the other 50 percent in proportion to their Seasonal CRR Eligible Quantities. In each Monthly CRR Allocation during CRR Year One, source verification will be required in Tier 1 as in the annual allocation process. Following the verification process, the CAISO will calculate and set aside for the Monthly CRR Auction 50 percent of the import capacity that remains at each Scheduling Point after accounting for the verified Scheduling Point CRR Source submissions to the monthly process and the Annual CRR Allocation and Auction results for that month, and will allow LSEs to nominate monthly CRRs with CRR Sources at each Scheduling Point in quantities up to their pro rata shares of the other 50 percent in proportion to their Monthly CRR Eligible Quantities. In the Annual CRR Allocation processes subsequent to CRR Year One, there will be no special provisions regarding CRR Sources at Scheduling Points in Tiers 1 and 2. For Tier 3 the CAISO will calculate and set aside for the Annual CRR Auction 50 percent of the import capacity at each Scheduling Point that remains after the Tier 1 and Tier 2 allocations. In the Monthly CRR Allocation processes subsequent to CRR Year One there will be no special provisions regarding CRR Sources at Scheduling Points in Tier 1. For Tier 2 the CAISO will calculate and set aside for the Monthly CRR Auction 50 percent of the import capacity that remains at each Scheduling Point after accounting for the Annual CRR allocation and auction results for that month and Tier 1 of the monthly CRR Allocation.

36.8.5 Load Migration Between LSEs.

Load migration between LSEs will be reflected in the hourly load data and load forecasts used by the CAISO to calculate the CRR Load Metrics and CRR Eligible Quantities for each LSE, in accordance with procedures set forth in the applicable BPM. When load migration occurs during an annual CRR cycle, such migration will be reflected in appropriate adjustments to each affected LSE's CRR Eligible Quantities in subsequent annual and monthly CRR Allocations, as well as its PNP Eligible Quantities in the next annual CRR allocation. In addition, an LSE that loses load through load migration is required to make a cash payment to the LSE that acquires that load, in an amount equal to the value of a pro rata share of the first LSE's current holdings of Seasonal CRRs for the remainder of the current annual CRR cycle from the date the load migration takes effect.

36.8.5.1 Load Migration Reflected in the Annual Allocation Process.

An LSE who loses or gains net Load through Load migration in a given year will have its Seasonal CRR Eligible Quantities in the next Annual CRR Allocation reduced or increased, respectively, in proportion to the net Load lost or gained through Load migration. In addition, an LSE who loses Load through Load migration in a given year will have its PNP Eligible Quantities reduced in proportion to the gross amount of Load lost through Load Migration. The reduction in PNP Eligible Quantities will be applied as a constant percentage to all CRRs allocated to that LSE in the prior annual CRR Allocation. There is no increase in an LSE's PNP Eligible Quantities due to an increase in Load due to Load migration. Such an LSE may acquire additional CRRs for net Load gained in Tiers 2 and 3 of the subsequent annual CRR Allocation. The CAISO will reserve CRRs in the annual PNP corresponding to the CRRs released by LSEs whose PNP Eligible Quantities were reduced, and will then release these CRRs for Tiers 2 and 3. This mechanism will ensure, in the event that changes to the DC FNM prevent the full allocation of PNP

Eligible Quantities, that CRRs nominated in the PNP undergo the same proportional reduction as CRRs released by the LSEs who lose Load due to Load migration, so as not to unfairly disadvantage those LSEs who gain Load through Load migration. The Load-gaining LSE will not be required to request the precise CRRs released by the relevant Load-losing LSE but will be able to nominate its preferred CRRs in Tiers 2 and 3.

36.8.5.1.1 Mid-Year Adjustments in Seasonal CRR Holdings.

If an LSE loses Load through Load migration to another LSE at any time between annual CRR Allocations, the load-losing LSE must compensate the Load-gaining LSE in one of two manners. First, using the SRS, the load-losing LSE may transfer a percentage of its Seasonal CRR holdings, for the remainder of the annual CRR cycle and for both on-peak and off-peak periods, to the load-gaining LSE in a quantity proportionate to the percentage of its Load lost to the other LSE through migration. Alternatively, the LSE who loses Load through Load migration to another LSE may make cash payments to the relevant Load-gaining LSE in a value commensurate with the hourly CRR Payment stream that would have accrued to the CRRs transferred, if the SRS transfer option were chosen.

36.8.5.2 Load Migration Reflected in the Monthly Allocation Process.

An LSE who loses or gains net Load through Load migration must reflect that loss or gain in the monthly Load forecasts it submits to the CAISO for determining its monthly CRR Eligible Quantities for future monthly CRR allocations.

36.8.5.3 Adjustments for Load Growth.

LSEs who experience Load growth that is not due to Load migration will reflect such Load growth in the data submitted to the CAISO for determining Seasonal and Monthly CRR Eligible Quantities for the CRR Allocation processes.

36.8.6 Load Forecasts Used to Calculate CRR MW Eligibility.

The CAISO will work closely with appropriate state and Local Regulatory Authorities and agencies to ensure that historical load data and load forecasts used to establish CRR Eligible Quantities are consistent with the data and forecasts used to establish Resource Adequacy Requirements.

36.9 CRR Allocation to LSEs serving External Load.

LSEs serving Load outside the CAISO Control Area who wish to nominate and be allocated CRR Obligations in the same annual and monthly allocation processes described in Section 36.8 may do so subject to the provisions of this Section. LSEs serving Load outside the CAISO Control Area may participate in the CRR Allocation processes and be allocated CRRs to the extent that: (1) such LSEs makes a showing of legitimate need for the CRRs nominated; (2) such entities pre-pay the appropriate Wheeling Access Charge in the amount of MWs of CRRs nominated; (3) the nominated CRRs clear the relevant SFTs; and (4) the external load for which CRRs are nominated is not served through an ETC, TOR or Converted Rights which as been designated as eligible to receive the reversal of Congestion Charges. Such LSEs that participate in the CRR Allocation processes will be subject to the applicable rules governing the tiered structure of these processes as described in Sections 36.8. All CRRs allocated under the terms of this Section 36.9 will be CRR Obligations.

36.9.1 Showing of Legitimate Need.

LSEs serving load outside the CAISO Control Area must make a showing to the CAISO of legitimate need for the CRRs requested. The determination of legitimate need will be based on demonstration of an existing contract for Generation internal to the CAISO Control Area that covers the time period of the CRRs nominated, or ownership of a Generating Unit internal to the CAISO Control Area.

36.9.2 Prepayment of Wheeling Access Charges.

LSEs serving load outside the CAISO Control Area will be required to prepay relevant Wheeling Access Charges in order to participate in the CRR Allocation processes and be allocated CRRs. For each MW of CRR nominated the nominating LSE must prepay one MW of the relevant Wheeling Access Charge, which equals the per-MWh WAC that is expected at the time the allocation process is conducted to be applicable for the period of the CRR nominated, times the number of hours comprising the period of the CRR nominated. To the extent that an LSE prepays a quantity of the WAC and is not allocated the full amount of CRRs nominated, WAC prepayment for CRRs not allocated will be refunded by the CAISO within a reasonable time following the completion of the relevant allocation process.

36.9.3 CRR Eligible Quantities.

The CAISO will calculate the Seasonal and Monthly CRR Eligible Quantities for LSEs serving external Load as described in Section 36.8.2 with the following modifications. The Load data submitted by the

LSE from which the CAISO will construct load duration curves for determining the Seasonal and Monthly CRR Eligible Quantities must reflect the LSE's historical hourly exports at the Scheduling Point that is the CRR Sink of the nominated CRRs. LSEs that wish to nominate multiple Scheduling Points as CRR Sinks in the allocation process will have distinct CRR Eligible Quantities for each nominated Scheduling Point, and must submit historical hourly export data at each such Scheduling Point from which the CAISO will calculate the associated CRR Eligible Quantities.

36.9.4 Eligible Sources and Sinks.

Eligible CRR Sources will be the PNodes of the Generating Units for which the LSE has made a legitimate need showing as described above. Eligible CRR Sinks will be the Scheduling Points for which the CAISO has established CRR Eligible Quantities based on the LSE's submitted historical hourly export data. External Load Serving Entities requesting CRRs whose CRR Source is a specific Generating Unit will be limited to seventy-five percent (75%) of that Generating Unit's PMax in Tiers 1 and 2 of the annual CRR Allocation process in CRR Year One.

36.9.5 Priority Nomination Process.

CRRs allocated pursuant to this Section 36.9 shall be eligible for nomination in the Priority Nomination Process to the extent that the requirements of this Section 36.9 are met at the time of the relevant CRR Allocation.

36.10 CRR Allocation to Metered Subsystems.

An MSS that elects gross settlement may participate in the CRR allocation processes and be allocated CRR Obligations in accordance with Section 36.8. An MSS that elects net settlement may participate in the CRR allocation processes and be allocated CRRs in accordance with Section 36.8, except that its CRR Eligible Quantities will reflect its net load and its allocated CRRs will use MSS-LAPs as CRR Sinks. The MSS will be required to submit to the CAISO the appropriate hourly historical net Load data and net Load forecast data from which the CAISO will construct net Load duration curves to determine the CRR Eligible Quantities.

36.11 CRR Allocation to Merchant Transmission Upgrades.

Sponsors of merchant transmission upgrades who turn such facilities over to CAISO operational control and do not recover the cost of the transmission investment through the CAISO's TAC or WAC or other regulatory cost recovery mechanism may be allocated CRR Options that reflect the contribution of the upgrade to grid transfer capacity as determined in accordance with Section 24.7.3.

36.12 [NOT USED]

36.13 CRR Auction.

The CAISO shall conduct CRR Auctions on an annual and monthly basis subsequent to each annual and monthly CRR Allocation process. Candidate CRR Holders may bid to purchase and may acquire CRRs Obligations through the CAISO's annual and monthly CRR Auctions in accordance with the provisions of this Section 36.13.

36.13.1 Scope of the CRR Auctions.

The CAISO will conduct a CRR Auction corresponding to and subsequent to the completion of each CRR Allocation process, and prior to the start of the period to which the auctioned CRRs will apply. Each CRR Auction will release CRRs having the same seasons, months and time-of-use specifications as the CRRs released in the corresponding CRR Allocation. Each CRR Auction will utilize the same DC FNM that was utilized in the corresponding CRR Allocation. For each CRR Auction, the CRRs allocated in the corresponding CRR Allocation will be modeled as fixed injections and withdrawals on the DC FNM and will not be adjusted by the SFT in the CRR Auction process. Thus the CRR Auction will release only those CRRs that are feasible given the results of the corresponding CRR Allocation. CRRs released in a CRR Auction will be indistinguishable from CRRs released in the corresponding CRR Allocation for purposes of settlement and secondary trading. The following limitations apply. First, participants in the CRR Auctions will have more choices regarding CRR Sources and CRR Sinks than are eligible for nomination in the CRR Allocations, as described in Section 36.13.5. Second, to the extent a Market Participant receives CRRs in both a CRR Allocation and the corresponding CRR Auction, the CRRs obtained in the CRR Auction will not be eligible for nomination in the PNP. Third, the CRR Auction cannot be used by CRR Holders to offer for sale CRRs they acquired in a prior CRR Allocation or CRR Auction. Sales or transfers of CRR holdings may only be done through bilateral transactions, and then must be registered in the SRS as described in Section 36.7.

36.13.2 Responsibilities of the CAISO Prior to Each Auction.

The CAISO shall publish on the CAISO Website a notice of upcoming CRR Auctions at least seven (7) days prior to the CRR auction. The CAISO will also provide additional information needed by CRR Auction participants in accordance with the provisions of Section 6.5.1.

36.13.3 CRR Holder Creditworthiness.

All Market Participants are eligible to acquire CRRs by participating in the CRR Auction, provided that the Market Participant has met all the CRR Holder requirements described in Section 36.5, the creditworthiness provisions in Section 12 and the relevant Business Practice Manual.

36.13.4 Bids in the CRR Auctions.

Bids to purchase CRRs shall be submitted in accordance with the requirements set out in this Section 36.13.4 and as further specified in the applicable Business Practice Manuals. Once submitted to the CAISO, CRR bids may not be cancelled or rescinded by the Market Participant after the auction is closed. Market Participants may bid for Point-to-Point CRRs and Multi-Point CRRs. Each bid for a Point-to-Point CRR shall specify:

a) The associated month or season and time-of-use period;

b) The associated CRR Source and CRR Sink;

c) A monotonically non-increasing piecewise linear bid curve in quantities (denominated in tenths of MW) and prices ($/MW).

Each bid for a Multi-Point CRR shall specify:

d) The associated month or season and time-of-use period;

e) The associated CRR Sources and CRR Sinks;

f) For each CRR Source, a monotonically non-decreasing piecewise linear bid curve in quantities (denominated in tenths of MW) and prices ($/MW).

g) For each CRR Sink, a monotonically non-increasing piecewise linear bid curve in quantities (denominated in tenths of MW) and prices ($/MW).

Bid prices in all CRR bids may be negative.

36.13.5 Eligible Sources and Sinks for CRR Auction.

Allowable CRR Sources for CRRs acquired in the CRR Auction will be Generator PNodes, Scheduling Points, Trading Hubs, LAPs, MSS-LAPs and sub-LAPs. Allowable CRR Sinks for CRRs acquired in the

CRR Auction will be Generator PNodes, Scheduling Points, Trading Hubs, LAPs, MSS-LAPs and Sub-LAPs.

36.13.6 Clearing of the CRR Auction.

The SFT used to clear the CRR Auction will utilize the same DC FNM and optimization algorithm as the corresponding CRR Allocation, except that nominations to the CRR Auction will have associated price-quantity bid curves. The CRR Auction SFT will use the bid prices in determining which CRRs to award when not all nominations are simultaneously feasible, will select the set of simultaneously feasible CRRs with the highest total auction value as determined by the CRR bids, and will calculate nodal prices at each PNode of the DC FNM. In the event that there are two or more identical bids for a specific combination of CRR Source and CRR Sink, and there is insufficient network capacity to accommodate all of the identical bids, each such CRR bidder will receive a pro rata share of the CRRs that can be awarded. Based on the nodal prices calculated by the CRR Auction SFT, the CRR Market Clearing Price per MW for a specific CRR will equal the nodal price at the CRR Sink minus the nodal price at the CRR Source. For a Multi-Point CRR the CRR Market Clearing Price will equal the sum over all relevant CRR Sinks of the nodal price at each CRR Sink times that CRR Sink's share of the total MW of the CRR, minus the sum over all relevant CRR Sources of the nodal price at each CRR Source times that CRR Source's share of the total MW of the CRR Market Participants shall pay the associated CRR Market Clearing Prices for all CRRs bought through the CRR Auction.

36.13.7 Announcement of CRR Auction Results.

Within five (5) business days after the close of a CRR Auction, the CAISO shall post the results. The results shall include but are not limited to the MW quantity, the CRR Source and CRR Sink for each CRR awarded, the nodal prices calculated by the CRR Auction SFT, and the parties to whom the CRRs were awarded. The CAISO shall not disclose prices specified in any CRR bid.

~~36 FIRM TRANSMISSION RIGHTS.~~

~~36.1 General.~~

~~**36.1.1** Commencing in 2000, on the effective date established by the ISO Governing Board, the ISO shall make FTRs available in the amounts determined in accordance with Section 36.3, with the rights and other characteristics described in Sections 36.2, 36.6, 36.7 and 36.8, and through the processes described in Section 36.4. Proceeds of the ISO's auction of FTRs shall be distributed as described in Section 36.5. The owners of FTRs shall be entitled to share in Usage Charge revenues associated with Inter-Zonal Congestion in accordance with Section 36.6, and to scheduling priority in the event of Congestion in the Day-Ahead Market, as described in Section 36.7. For the purpose of Section 36, the term "Zone" shall be construed to mean both "Zone" and "Scheduling Point."~~

~~**36.2 Characteristics of Firm Transmission Rights**.~~

~~**36.2.1** Each FTR shall be defined by a transmission path from an originating Zone to a contiguous receiving Zone. Each FTR shall entitle the FTR Holder to a share of Usage Charges attributable to Inter-Zonal Congestion for transfers on that path from the designated originating Zone to the designated receiving Zone in accordance with Section 36.6. An FTR is a right in one direction only. An FTR Holder shall not be entitled to share in (i) Usage Charges attributable to Inter-Zonal Congestion from the designated receiving Zone to the designated originating Zone; or (ii) Usage Charges payable in accordance with Section 27.1.2.1.5.1 to a Scheduling Coordinator that counter-schedules from the designated originating Zone to the designated receiving Zone.~~

~~**36.2.2** The ISO Governing Board shall, from time to time, approve the amount of FTRs to be auctioned for each FTR Market and the ISO shall publish this information on the ISO Home Page at least thirty (30) days prior to the auction. The ISO may issue FTRs in one or more auctions in any year so long as the total FTRs for any interface do not exceed the maximum amount permitted in Section 36.3.~~

~~**36.2.2.1** Should the ISO create additional Zones or otherwise change the ISO's defined Inter-Zonal Interface, and if such changes would affect outstanding FTRs, such changes will not take effect prior to the expiration date of any such outstanding FTRs. The ISO shall also publish an announcement of any such pending changes on the ISO Home Page and WEnet at least thirty (30) days prior to the applicable FTR auction.~~

~~**36.2.2.2** Any additional FTRs auctioned as a result of changes in the ISO's defined Inter-Zonal Interfaces shall not affect the rights associated with existing FTRs.~~

~~**36.2.3** Each FTR shall be issued in the denomination of 1 MW. The initial release of FTRs shall start with the hour beginning at 12:00 a.m., on February 1, 2000 and end with the hour beginning at 11:00 p.m., on March 31, 2001. An FTR shall not afford the FTR Holder any right to share in Usage Charges attributable to Inter-Zonal Congestion occurring in any hour before or after the term of the FTR.~~

~~**36.2.4** The portion of the Usage Charges to which the FTR Holder is entitled shall be determined in accordance with Section 36.6.~~

~~**36.2.5** FTR Holders shall be entitled to priority in the scheduling of Energy in the Day-Ahead Market as specified in Section 36.7.~~

~~**36.2.6** Any entity, with the exception of the ISO, shall be eligible to acquire FTRs by participating in the ISO's auction of FTRs, as described in Section 36.4, or by purchasing FTRs in secondary markets. To participate in the ISO's auction of FTRs, an entity must either be a certified Scheduling Coordinator or have met financial requirements equivalent to the financial certification criteria required of all Scheduling Coordinators. An entity may not acquire FTRs with a total value that exceeds the financial security proved by that entity to the ISO. In addition, an FTR Bidder must have, or have access to, the necessary technical equipment to participate in the electronic auction.~~

~~**36.2.7** All entities which acquire FTRs by participating in the ISO's auction of FTRs, as described in Section 36.4, directly from the ISO pursuant to Section 36.4.3, or by purchasing FTRs in secondary markets, must register as an FTR Holder with the ISO. To complete this registration, the FTR Holder must notify the ISO, through the form specified for that purpose by the ISO, of all Affiliates of the FTR Holder that are themselves FTR Holders or Market Participants. The requirement that an FTR Holder notify the ISO of all Affiliates that are FTR Holders or Market Participants is continuing for as long as the FTR Holder owns FTRs, and FTR Holders must provide the ISO with supplemental notification concerning FTR Holders and/or Market Participants that become affiliated with the FTR Holder or Affiliates that subsequently become FTR Holders or Market Participants in order to satisfy this requirement.~~

~~**36.3 Maximum Number of Firm Transmission Rights.**~~

~~**36.3.1** On each Inter-Zonal Interface and direction combination for which FTRs are issued, the ISO shall issue a number of FTRs that is less than or equal to the difference between:~~

~~(i) The WECC approved path rating of the interface in the direction from the originating Zone to the receiving Zone or, if the interface has not received a WECC approved rating, a rating determined by a methodology that is consistent with the WECC's rating methodology; and~~

~~(ii) The portion of the transfer capability of the interface available for transmission scheduling under Existing Contracts as Existing Rights.~~

~~and ensures the ISO's ability to honor all of its FTRs simultaneously under normal operating conditions.~~

~~36.4 Issuance of Firm Transmission Rights by the ISO.~~

~~36.4.1~~ ~~The ISO shall make FTRs available by conducting an annual primary auction of FTRs, commencing approximately two months before the beginning of the term of the FTRs; provided; however that for the initial FTR release, the primary auction shall be as determined by the ISO Governing Board. The auction of FTRs shall be a simultaneous multi-round, clearing price auction conducted separately and independently, as set forth in Section 36.4.2, for each FTR Market. In addition, if the ISO Governing Board decides to make available, between annual auctions, FTRs in addition to those that were purchased in the last annual auction, the ISO may conduct additional auctions of such FTRs in accordance with Section 36.4.2. The term of such FTRs shall only be for the remaining duration of the FTR term defined for the primary auction applicable to the year during which they were issued.~~

~~36.4.2 The ISO shall conduct the auction of FTRs through the following procedures:~~

~~36.4.2.1~~ ~~At least thirty (30) days prior to the scheduled start of the auction, the ISO shall post on the ISO Home Page the following information:~~

~~(i) the number of FTRs to be issued for each FTR Market;~~

~~(ii) the starting bid price at which FTRs will be made available in each FTR Market in the first round of the auction, which price will be set in each FTR Market at a level equal to the greater of (a) $100 per MW-year; (b) twenty (20) percent of the ratio of the net Usage Charges collected by the ISO with respect to that FTR Market in the most recent twelve-month period for which data are available to the total MW-years of Energy scheduled over the Inter-Zonal Interface in the relevant direction during that period; or (c) twenty (20) percent of the ration of the net Grid~~

~~Operation Charges (for new Inter-Zonal Interfaces that previously were transmission paths within a Zone) collected by the ISO in the most recent twelve-month period for which data are available to the total MW-years of Energy scheduled over the transmission paths in the relevant direction during that period, provided that, if data are available for only a portion of the twelve-month period, such data shall be used on annualized basis;~~

~~(iii) the formula through which the ISO will determine how much to adjust the price of FTRs in each FTR Market for subsequent rounds of the auction, including the initial coefficients to be used in the formula and the range over which the coefficients may be adjusted in accordance with Section 36.4.2.3;~~

~~(iv) the date and time prior to the commencement of the auction by which each entity desiring to bid on FTRs must have satisfied the necessary financial requirements as outlined in Section 36.2.6;~~

~~(v) the specifications for the technical equipment necessary to participate in the auction, which will be conducted electronically, the date and time by which bids must be submitted in the first round of the auction, which shall be the same for all FTR Markets, and the form and format in which bids must be submitted; and~~

~~(vi) a schedule for the conduct of subsequent rounds of the auction, including the interval between rounds of the auction and the anticipated duration of the auction.~~

~~**36.4.2.2**~~ ~~On or before the date specified in Section 36.4.2.1(v), any entity desiring to obtain FTRs in the ISO's auction must submit, via equipment satisfying the technical requirements specified in accordance with Section 36.4.2.1(v), a bid for each FTR Market in which the entity desires to participate, specifying the number of FTRs the entity is willing to purchase at the price specified in Section 36.4.2.1(ii). All individual bids will remain confidential throughout all rounds of the auction in each FTR Market. Once submitted to the ISO, a bid for FTRs in any round of an auction may not be cancelled or rescinded by the FTR Bidder. The ISO shall announce simultaneously to all FTR Bidders the total quantity of FTRs for which valid bids are submitted for each FTR Market.~~

~~**36.4.2.3** In each round of the auction following the first round, the ISO will increase the price at which FTRs are made available in each FTR Market in accordance with the formula posted in accordance with Section 36.4.2.1(iii), or in accordance with any adjustment to the coefficients in that formula that is announced by the ISO to the FTR Bidders at least one round in advance of the round for which the adjustment is made. Price increases need not be uniform for all FTR Markets. In the case of an FTR Market in which the demand for FTRs in the preceding round is less than or equal to the quantity of FTRs being made available, the price shall not increase and the auction for that FTR Market shall close. After each round of the auction, the ISO shall announce simultaneously to all FTR Bidders the total quantity of FTRs for which valid bids were submitted in each FTR Market, whether the auction for each FTR Market is closed, and, the revised prices for the following round of the auctions that remain open. Within the timeframe set by the ISO in accordance with Section 36.4.2.1(vi), each FTR Bidder may submit bids for the quantity of FTRs it desires to purchase in each FTR Market at the revised price, provided that an FTR Bidder may not bid for a number of FTRs in an FTR Market that exceeds the total number of FTRs in that FTR Market for which that entity submitted bids in the preceding round of the auction. The ISO shall conduct subsequent rounds of the auction in each FTR Market until the demand for FTRs in the FTR Market is less than or equal to the quantity of FTRs being made available, at which point the auction shall be closed in that FTR Market.~~

~~**36.4.2.4** Subject to Section 36.4.2.5, each successful FTR Bidder shall receive a number of FTRs in each FTR Market equal to the number of FTRs for which it bid in the last round of the auction for that FTR Market.~~

~~**36.4.2.5** For any FTR Market in which, when the auction has closed, the number of FTRs being made available exceeds the demand for FTRs in that FTR Market in the last round of the auction, each FTR Bidder shall be awarded a number of FTRs determined in accordance with the following formula, provided that, if the number of FTRs that would be awarded under the formula to an FTR Bidder that did not submit a bid in the last round of the auction is less than five percent (5%) of the initial bid submitted by that FTR Bidder for the FTR Market, that FTR Bidder shall have the option of declining the award of FTRs resulting from the formula:~~

~~N = B + [(R / TR) * D]~~

~~where~~

~~N = The total number of FTRs awarded to an FTR Bidder for an FTR Market, which shall be in whole MWs and shall not exceed the number of FTRs for which that FTR Bidder bid in the round preceding the final round of the auction;~~

~~B = The number of FTRs for which an FTR Bidder bid in the final round of the auction for the FTR Market in accordance with Section 36.4.2.4 (or zero, if the FTR Bidder did not bid in that round);~~

~~R = The difference between the number of FTRs for which the FTR Bidder bid in the round preceding the final round of the auction and B, but not less than zero;~~

~~TR = The total of the demand reductions (R) for all FTR Bidders that submitted bids in the last round of the auction (treating the failure by an FTR Bidder to submit a bid as a bid of zero); and~~

~~D = The difference between the total demand for FTRs in the final round of the auction and the quantity of FTRs being made available for the FTR Market.~~

~~**36.4.2.6** The price of FTRs in an FTR Market shall be the last price at which the demand for FTRs in the FTR Market exceeded or equaled the quantity of FTRs being made available pursuant to Section 36.4.2.1(i), except that, if the demand for FTRs in an FTR Market in the first round of the auction was less than the quantity of FTRs being made available for that FTR Market, the price of FTRs in that FTR Market shall be the first round price and each FTR Bidder in that FTR Market will receive a number of FTRs equal to the quantity of bids they submitted in the first round. Any remaining FTRs in that FTR Market will not be awarded in that auction.~~

~~**36.4.2.7** Each FTR Bidder shall pay the ISO an amount equal to the sum, for all FTR Markets, of the products of the FTR price in each FTR Market (determined in accordance with Section 36.4.2.6) and the total quantity of FTRs awarded to that FTR Bidder in that FTR Market (determined in accordance with Section 36.4.2.4 or Section 36.4.2.5, as applicable). FTR Bidders shall pay the amount determined in accordance with the foregoing sentence within ten (10) Business Days of receiving an invoice from the ISO by making payment to the ISO Clearing Account in accordance with Section 11.10. If the FTR Bidder fails to make timely payment of the full amount due, the ISO may enforce any guarantee, letter of credit or~~

~~other credit support provided by the defaulting FTR Bidder in accordance with Section 36.2.6 and, if the ISO is required to institute proceedings to collect any unpaid amount, the defaulting FTR Bidder shall pay Interest on the unpaid amount for the period from the Payment Date until the date on which payment is remitted to the ISO Clearing Account.~~

~~**36.4.2.8** The ISO shall post on the ISO Home Page the prices at which FTRs are sold in each FTR Market through the primary auction.~~

~~**36.4.3** For the ten-year transition period described in Section 4 of Schedule 3 to Appendix F, a New Participating TO that has an obligation to serve Load shall receive FTRs for Inter-Zonal Interfaces to which the transmission facilities and Converted Rights for Inter-Zonal Interfaces that the New Participating TO turns over to the ISO's Operational Control give it transmission rights, provided such transmission facilities are Existing High Voltage Facilities. The amount of FTRs will be determined when the Transmission Control Agreement is executed and shall be commensurate with the transmission capacity the New Participating TO is turning over to ISO Operational Control. The ISO will submit to FERC in the transmittal letter for the amendment to the Transmission Control Agreement regarding each New Participating TO the amount of FTRs allocated to such New Participating TO. The amount of FTRs that has been determined will not be effective until after FERC issues an order concerning the amendment required by this section. No additional FTRs will be issued to New Participating TOs for building High Voltage Transmission Facilities after they become Participating TOs. FTRs issued in accordance with this section shall entitle the FTR Holder to receive Usage Charge revenues and to priority in the scheduling of Energy in the Day-Ahead Market in accordance with the provisions of the ISO Tariff. FTRs associated with Converted Rights shall terminate on the earlier of termination of the Existing Contract or the end of the ten-year transition period.~~

~~**36.5 Distribution of Auction Revenues Received by the ISO for Firm Transmission Rights.**~~

~~**36.5.1** For each Inter-Zonal Interface and direction for which an FTR is defined, the total proceeds received by the ISO through the auction described in Section 36.4 shall be allocated and paid by the ISO to the Participating TO that is entitled in accordance with Section 27.1.2.1.6 to receive Usage Charge revenues with respect to the corresponding Inter-Zonal Interface. Each Participating TO shall~~

~~credit its FTR auction proceeds against its high voltage TRBA if the FTR is for a High Voltage Transmission Facility or against its low voltage TRBA if the FTR is a for a Low Voltage Transmission Facility.~~

~~**36.5.2** In the event the transmission facilities or rights making up an Inter-Zonal Interface with respect to which FTRs are defined are owned by more than one Participating TO, the proceeds of the auction of such FTRs shall be allocated to those Participating TOs who auction FTRs in proportion to the FTRs associated with their Inter-Zonal Interface as of the date of the FTR auction compared to all FTRs auctioned for such Inter-Zonal Interface.~~

~~**36.5.3** In the event the transmission facilities or rights making up an Inter-Zonal Interface with respect to which FTRs are defined have been upgraded resulting in increased transmission capacity on the Inter-Zonal Interface, and the costs of construction and operation were paid for by a Project Sponsor pursuant to Section 24.7.1 and were not included in the ISO's transmission Access Charge or a reimbursement or direct payment from a Participating TO, the proceeds of the auction of such FTRs shall be allocated to the Project Sponsors according to the allocated shares determined as set forth in Section 24.7.3(d).~~

~~**36.6 Distribution of Usage Charges to FTR Holders.**~~

~~**36.6.1** The FTR Holder shall be entitled to receive from the ISO a portion of the total Congestion revenues related to Inter-Zonal Congestion calculated by the ISO in the Day-Ahead Market and collected by the ISO with respect to the Inter-Zonal Interface and direction combination for which the FTR was defined. This portion equals the Usage Charge calculated by the ISO in the Day-Ahead Market for the transfer of 1 MW from the originating Zone to the receiving Zone during each hour in which Usage Charges apply, multiplied by the number of FTRs owned by that FTR Holder, subject to adjustment in accordance with Section 36.6.3.~~

~~**36.6.2** In addition, an FTR Holder shall be entitled to receive a portion of the additional net Usage Charges related to Inter-Zonal Congestion calculated by the ISO in the Hour-Ahead Market and collected by the ISO with respect to the Inter-Zonal Interface and direction combination for which the FTR was defined. The FTR Holder shall receive a portion of the net Usage Charges in the Hour-Ahead Market proportionate to the share of the Usage Charges it received in the Day-Ahead Market in accordance with~~

~~Section 36.6.1.~~

~~**36.6.3** When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is less than its scheduling capacity, determined in accordance with Section 36.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be reduced until and unless the entitlements of Participating TOs associated with that FTR Market to Usage Charge revenues in accordance with Section 27.1.2.1.6 have been reduced to zero. In that event, the financial entitlements associated with the corresponding FTRs shall be multiplied by a factor equal to the amount of scheduling capability available to holders of the remaining FTRs divided by the number of such FTRs. When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is greater than its scheduling capacity, determined in accordance with Section 36.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be increased.~~

~~**36.6.4** When the Congestion Usage Charges calculated and collected by the ISO from the Hour-Ahead Market with respect to transfers across an Inter-Zonal Interface in a particular direction result in a net obligation to the ISO, in the circumstances described in Section 27.1.2.1.7, the provisions of this Section 9.6 shall continue to apply, and FTR Holders shall be required to pay the ISO these amounts.~~

~~**36.6.5** The ISO will calculate the Congestion Usage Charge revenues to be credited or debited to the account of each FTR Holder on an hourly basis. Such calculation will identify the Inter-Zonal Interface and direction to which each credit or debit applies.~~

~~**36.7 Scheduling Priority of FTR Holders.**~~

~~**36.7.1** FTRs will not affect the ISO's dispatch and operation of the ISO Controlled Grid except that each FTR Holder will have a priority, as described in this Section 36.7, for the scheduling of Energy in the Day-Ahead Market when an Inter-Zonal Interface experiences Inter-Zonal Congestion in the direction for which its FTR is defined. Any FTRs not used in Preferred Schedules in the Day-Ahead Market for any hour have no scheduling priority for that hour in the Trading Day. FTR Holders shall have no scheduling priority in the Hour-Ahead Market or in real-time operations.~~

~~**36.7.2** When Inter-Zonal Congestion is experienced or projected to be experienced in the Day-Ahead Market, the ISO shall first attempt to relieve the Inter-Zonal Congestion using Adjustment Bids~~

~~submitted by Scheduling Coordinators in accordance with Section 27.1.1.4.~~

~~**36.7.2.1** If the ISO is unable to relieve the Day-Ahead Inter-Zonal Congestion using Adjustment Bids, then the ISO will allocate Day-Ahead inter-zonal transmission capacity first to Schedules of Market Participants that are using Existing Contract rights that have higher scheduling priority than Converted Rights capacity and second to Market Participants who hold FTRs and have indicated to the ISO that they wish to exercise their scheduling priority option. The ISO will allocate any remaining transmission capacity to remaining Market Participants' Schedules pro rata.~~

~~**36.7.3** When the scheduling capability of an Inter-Zonal Interface is less than or greater than its normal scheduling capability prior to the Day-Ahead Market, as described in Section 36.6.3, the priority scheduling rights of FTR Holders, as described in Section 36.7.2, shall remain constant (in MWs) to the extent that the total scheduling rights of FTR Holders do not exceed the total Interface scheduling capability of the associated Inter-Zonal Interface after adjustments have been made for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights. If the total Interface scheduling capability, adjusted for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights, is less than the total of all scheduling capability represented by FTR Holders who have chosen to exercise the FTR scheduling priority option, scheduling capability shall be allocated to FTR Holders pro rata.~~

~~**36.7.4 The scheduling priority of FTR Holders:**~~

~~(i) Shall not apply in the Hour-Ahead Market or in real-time dispatch and operation of the ISO Controlled Grid;~~

~~(ii) Shall not apply to any transfer of Energy other than a transfer across the Inter-Zonal Interface in the direction for which the FTR was defined during the hour or hours during which the circumstances described in Section 36.7.2.1 apply; and~~

~~(iii) Shall not be transferable, except in connection with a transfer of the FTR that is registered with the ISO, as described in Section 36.8.~~

~~**36.8 Assignment of Firm Transmission Rights.**~~

~~**36.8.1** An FTR may be assigned, sold, or otherwise transferred by the FTR Holder to any entity eligible to be an FTR Holder in full MW increments, either for the entire term of the FTR or for any portion~~

~~of that term providing, however, that any such transfer shall be in full hour increments that correspond to the FTR issued to the FTR Holder. All FTRs that are so assigned, sold, or otherwise transferred by the FTR Holder are subject to the terms and conditions for FTRs approved by FERC and set forth in the ISO Tariff. Both the FTR Holder of record and the entity to which the FTRs have been transferred shall register the transfer of the FTR with the ISO by notifying the ISO through the form specified for that purpose by the ISO, and within the number of Business Days following the transfer published by the ISO on the ISO Home Page and WEnet but no later than such time as the ISO shall specify before the deadline applicable to scheduling Energy in the Day-Ahead Market, of (i) the identity of the FTR Holder of record; (ii) the identity of the entity to which the FTRs have been transferred; (iii) the quantity and identification numbers of the FTRs being transferred; (iv) the portion of the term of the FTR for which they are transferred; (v) the price at which the FTRs are being transferred; and (vi) whether the transfer of FTRs is subject to any conditions. The entity to which the FTRs have been transferred must also notify the ISO of all entities with which the transferee is affiliated that are FTR Holders or Market Participants as defined in the ISO Tariff, pursuant to Section 36.2.7. After the ISO receives such notices, the transferee shall be considered the FTR Holder of record with respect to the portion of the term of the FTR that is transferred. In order to use the Scheduling Priority of an FTR, pursuant to Section 36.7, an FTR must be registered with the ISO.~~

~~**36.8.2** The ISO shall publish on the ISO Home Page such information concerning the concentration of ownership of FTRs in each FTR Market as determined by the ISO Governing Board from time to time.~~

~~**36.8.3** To facilitate the operation of secondary markets in FTRs, the ISO shall post on WEnet and the ISO Home Page: (i) the identity of entities that hold FTRs that have been registered with the ISO, together with the quantity of FTRs held by such entities in each FTR Market and the path rating of the interface; and (ii) the name and a contact telephone number or telecopy number of any entity that operates a secondary market in FTRs and that requests the ISO to post such information. The ISO shall also post the prices at which FTRs are transferred through secondary market transactions and shall indicate whether such transfers are conditional.~~

37 ~~ENFORCEMENT PROTOCOL~~Rules of Conduct (Enforcement Protocol).

37.1 Objectives, Definitions, and Scope.

37.1.1 Purpose.

This Section sets forth the guiding principles for participation in the markets administered by the ~~California Independent System Operator~~CAISO. The specified Rules of Conduct are intended to provide fair notice to Market Participants of the conduct expected of them, to provide an environment in which all parties may participate on a fair and equal basis, to redress instances of gaming and other instances of anticompetitive behavior, and thereby to foster confidence of Market Participants, ratepayers and the general public in the proper functioning of the ~~ISO~~CAISO markets.

37.1.2 Objectives.

The objectives of this ~~ISO~~CAISO Tariff are to:

(a) Provide clear Rules of Conduct specifying the behavior expected of Market Participants; and

(b) Establish in advance the Sanctions and other potential consequences for violation of the specified Rules of Conduct.

37.1.3 Application of Other Remedies.

The activities and remedies authorized under this Section 37 are in addition to any other actions or relief that may be available to the ~~ISO~~CAISO elsewhere in the ~~ISO~~CAISO Tariff or under law, regulation or order. Nothing in this Section 37 limits or should be construed to limit the right of the ~~ISO~~CAISO to take action or seek relief otherwise available to it, and such action or relief may be pursued in lieu of or in addition to the action or relief specified in this Section 37.

37.1.4 FERC Authority.

In addition to any authority afforded Market Monitoring Unit in this Section 37, FERC shall have the authority to assess the sanctions, and otherwise to enforce the rules as set forth and described in this Section 37. FERC shall have authority to remedy a violation under this Section 37 from the date of the violation. Nothing in this Section 37 shall be deemed to be a limitation or condition on the authority of FERC or other entities under current law or regulation.

37.1.5 Administration.

The Marketing Monitor Unit will administer the Rules of Conduct specified herein, except for Section 37.7, which shall be administered by FERC, and except as provided in Section 37.2.5 and Section 37.4.4 . Nothing in this ~~ISO~~CAISO Tariff limits or should be construed to limit the ability of components of the ~~ISO~~CAISO organization other than the Market Monitoring Unit to ~~analyse~~analyze data and refer matters to the Market Monitoring Unit for enforcement.

37.2 Comply with Operating Orders.

37.2.1 Compliance with Orders Generally.

37.2.1.1 Expected Conduct.

Market Participants must comply with operating orders issued by the ~~ISO~~CAISO as authorized under the ~~ISO~~CAISO Tariff. For purposes of enforcement under this Section 37.2, an operating order shall be an order(s) from the ~~ISO~~CAISO directing a Market Participant to undertake, a single, clearly specified action (e.g., the operation of a specific device, or change in status of a particular Generating Unit) that is feasible and intended to resolve a specific operating condition. A Market Participant's failure to obey an operating order containing multiple instructions to address a specific operating condition will result in a single violation of Section 37.2. If some limitation prevents the Market Participant from fulfilling the action requested by the ~~ISO~~CAISO, then the Market Participant must promptly and directly communicate the nature of any such limitation to the ~~ISO~~CAISO. Compliance with ~~ISO~~CAISO operating orders requires a good faith effort to achieve full performance as soon as is reasonably practicable in accordance with Good Utility Practice.

37.2.1.2 Sanctions.

The Sanction for a violation of this Section shall be the greater of the quantity of Energy non-performance multiplied by the applicable ~~***Hourly Ex Post Price***~~ Dispatch Settlement Interval Locational Marginal Price or the following: for the first violation in a rolling twelve (12) month period, $5,000; for the second and subsequent violations in a rolling twelve (12) month period, $ 10,000. Sanctions under Section 37.2.1 will not be greater than $10,000 per violation and will be subject to the limitation stated in Section 37.2.6. If a quantity of energy cannot be objectively determined, then the financial sanctions specified above will apply. A Market Participant may incur Sanctions for more than one violation per day.

37.2.2 Failure to Curtail Load.

37.2.2.1 Expected Conduct.

A UDC or MSS Operator shall promptly comply with any ~~ISO~~CAISO operating order to curtail interruptible or firm load issued pursuant to the ~~ISO~~CAISO's authority under Section 7.7.11.3 ~~7.4.11.3~~ of the ~~ISO~~CAISO Tariff.

37.2.2.2 Sanctions.

The Sanction for non-compliance with an operating order to curtail load will be $10,000 for each violation.

37.2.3 Operations & Maintenance Practices.

37.2.3.1 Expected Conduct.

Market Participants shall undertake such operating and maintenance practices as necessary to avoid contributing to a major outage or prolonging response time as indicated by Section 7.7.13.3 ~~7.4.13.3~~ of the ~~ISO~~CAISO Tariff.

37.2.3.2 Sanctions.

The Sanction for a violation of Section 37.2.3 will be $10,000.

37.2.4 Resource Adequacy Availability.~~Must-Offer Denials/Revocations~~.

37.2.4.1 Expected Conduct.

A Market Participant shall start a Generating Unit ~~and have that Generating Unit~~ listed as a Resource Adequacy Resource by placing it on-line and/or available consistent with a DAM or RUC commitment or Real-Time Dispatch Instructions, unless the CAISO releases the Generating Unit after the RUC process is completed~~operating at minimum load within 30 minutes of the time at which a must-offer waiver revocation becomes effective~~, or ~~report the~~ a derate, outage or other event outside the control of the Market Participant ~~that~~ prevents the Generating Unit from being ~~started by such time~~ on-line and available. ~~Notwithstanding the foregoing, no violation shall occur unless the Market Participant has been provided advance notice of the waiver revocation consistent with the relevant start-up time set forth in the ISO Master File.~~ A Market Participant that fails to perform in accordance with the expected conduct described in this Section 37.2.4.1 shall be subject to Sanction.

37.2.4.2 Sanctions.

The Sanctions for a violation of Section 37.2.4 shall be as follows: for the first violation in a rolling twelve

(12) month period, $5,000; for the second and all subsequent violations in a rolling twelve (12) month period, $10,000. A Market Participant is limited to one Sanction per Generating Unit per calendar day.

37.2.5 Enhancements and Exceptions.

Except as otherwise specifically provided, penalty amounts shall be tripled for any violation of Section 37.2.1 through Section 37.2.4 if a~~n~~ ~~ISO~~CAISO System Emergency exists at the time an operating order becomes effective or at any time during the Market Participant's non-performance. Notwithstanding the foregoing, violations of Section 37.2.1 through Section 37.2.4 are subject to penalty under this rule only to the extent that the ~~ISO~~CAISO has issued a separate and distinct ~~non-automated~~ Dispatch Instruction to the Market Participant. Any penalty amount that is tripled under this provision and that would exceed the $10,000 per day penalty limit shall not be levied against a Market Participant until the ~~ISO~~CAISO proposes and the Commission approves such an enhancement. A Market Participant that is subject to an enhanced penalty amount under this Section 37.2.5 may appeal that penalty amount to FERC if the Market Participant believes a mitigating circumstance not covered in Section 37.9.2 exists. The duty of the Market Participant to pay the enhanced penalty amount will be tolled until FERC renders its decision on the appeal.

37.2.6 Per-Day Limitation on Amount of Sanctions.

The amount of Sanctions that any Market Participant will incur for committing two or more violations of Section 37.2.1 through Section 37.2.4 on the same day will be no greater than $10,000 per day.

37.3 Submit Feasible Energy ~~and~~ Bids, Ancillary Service Bids, and Submissions to Self-Provide an Ancillary Service ~~and Schedules~~.

37.3.1 Bidding Generally.

37.3.1.1 Expected Conduct.

Market Participants must submit Bids for~~bid~~ ~~and schedule~~ Energy and Ancillary Services and Submissions to Self-Provide an Ancillary Service from resources that are reasonably expected to be available and capable of performing at the levels specified in the ~~bid~~ Bid ~~and/or schedule~~, and to remain available and capable of so performing based on all information that is known to the Market Participant or should have been known to the Market Participant at the time of ~~bidding or scheduling~~submission.

37.3.1.2 Consequence for Non-Performance.

A Market Participant that fails to perform in accordance with the expected conduct described in Section 37.3.1.1 above shall be subject to having the payment rescinded for any portion of an Ancillary Service that is unavailable.

37.3.2 Exceptions.

Violations of Section 37.3.1 that result in circumstances in which an Uninstructed Deviation Penalty under Section ~~11.2.4.1.2~~ 11.23 of the ~~ISO~~CAISO Tariff may be assessed or for which payments have been eliminated under Section 8.10.~~2~~ 8 of the ~~ISO~~CAISO Tariff are not subject to Sanction under this section. The submission of a ~~Schedule~~ Bid or of a Submission to Self-Provide Ancillary Services that causes, or that the ~~ISO~~CAISO expects to cause ~~Intra-Zonal~~ Congestion shall not, by itself, constitute a violation of Section 37.3.1 unless the Market Participant fails to comply with an obligation under the ~~ISO~~CAISO Tariff to modify ~~Schedules~~ Bids as determined by the ~~ISO~~CAISO to mitigate such ~~congestion~~ Congestion or such ~~Schedules~~ Bids violate another element of this ~~R~~rule.

37.4 Comply with Availability Reporting Requirements.

37.4.1 Reporting Availability.

37.4.1.1 Expected Conduct.

A Market Participant shall report to the ~~ISO~~CAISO Control Center any Outage of a Generating Unit subject to Section 4.6 of the ~~ISO~~CAISO Tariff within thirty (30) minutes after the Outage occurs, in accordance with ~~Section 9.3.10.2~~ of the ~~ISO~~CAISO Tariff.

37.4.1.2 Sanctions.

The Sanctions for a violation of Section 37.4.1 shall be as follows: for the first violation in a rolling twelve (12) month period, a warning letter; for the second violation in a rolling twelve (12) month period, $1,000; for the third violation in a rolling twelve (12) month period, $2,000; for the fourth and subsequent violations in a rolling twelve (12) month period, $5,000. A Market Participant shall not be subject to more than one Sanction per Generating Unit per calendar day for violating Section 37.4.1. A “violation” shall mean each failure to report an Outage as required.

37.4.2 Scheduling and Final Approval of Outages.

37.4.2.1 Expected Conduct.

A Market Participant shall not undertake an Outage except as approved by the ~~ISO~~CAISO Outage

Coordination Office in accordance with Section 9.3.2, Section 9.3.9, and Section 9.3.6.6 of the ~~ISO~~CAISO Tariff. A Market Participant shall not commence any Outage without obtaining final approval from the ~~ISO~~CAISO Control Center in accordance with Sections 9.3.9 and 9.3.10 of the ~~ISO~~CAISO Tariff.

37.4.2.2 Sanctions.

The Sanctions for a violation of Section 37.4.2 shall be as follows: for the first violation within a rolling twelve (12) month period, $5,000; for subsequent violations within a rolling twelve (12) month period, $10,000. A "violation" shall mean each Outage undertaken for which all required approvals were not obtained.

37.4.3 Explanation of Forced Outages.

37.4.3.1 Expected Conduct.

A Market Participant, within two working days of the commencement of a Forced Outage, must provide an explanation of the Forced Outage to the ~~ISO~~CAISO that includes a description of the equipment failure or other cause and a description of all remedial actions taken by the Operator, in accordance with Section 9.3.10.5 of the ~~ISO~~CAISO Tariff. An Operator must promptly provide information requested by the ~~ISO~~CAISO to enable the ~~ISO~~CAISO to review the explanation submitted by the Operator and to prepare a report on the Forced Outage.

37.4.3.2 Sanctions.

The Sanction for failing to provide a timely explanation of Forced Outage shall be $500 per day for each day the explanation is late. The Sanction for failing to provide a timely response to information requested shall be as specified in Section 37.6.1.

37.4.4 Enhancements and Exceptions.

Except as otherwise specifically provided, penalty amounts shall be tripled for any violation of Section 37.4.1 through Section 37.4.3 that occurs during a~~n~~ ~~ISO~~CAISO System Emergency. Violations of the above rules that result in circumstances in which an Uninstructed Deviation Penalty under Section 11.23~~11.2.4.1.2~~ of the ~~ISO~~CAISO Tariff may be assessed shall not be subject to Sanction under this Section 37.4. A Market Participant that is subject to an enhanced penalty amount under this Section 37.4.4 may appeal that penalty amount to FERC if the Market Participant believes a mitigating circumstance not covered in Section 37.9.2 exists. The duty of the Market Participant to pay the enhanced penalty amount will be tolled until FERC renders its decision on the appeal.

37.5 Provide Factually Accurate Information.

37.5.1 Accurate Information Generally.

37.5.1.1 Expected Conduct.

All applications, ~~Schedules~~Bids, Submissions, reports, and other communications by a Market Participant or agent of a Market Participant to the ~~ISO~~CAISO, including maintenance and outage data, ~~bid~~ Bid data, transaction information, and load and resource information, must be submitted by a responsible company official who is knowledgeable of the facts submitted. The Market Participant shall provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with FERC, FERC-approved market monitors, FERC-approved regional transmission organizations, or FERC-approved independent system operators, or jurisdictional transmission providers, unless the Market Participant exercised due diligence to prevent such occurrences.

37.5.1.2 Sanctions.

The Sanctions for a violation of Section 37.5.1 shall be as follows: for the first violation within a rolling twelve (12) month period, $2,500; for the second violation within a rolling twelve (12) month period), $5,000; subsequent violations within a rolling twelve (12) month period, $10,000.

37.5.2 Inaccurate Meter Data.

37.5.2.1 Expected Conduct.

Market Participants shall provide complete and accurate Settlement Quality Meter Data for each ~~Trade~~ Trading ~~h~~Hour and shall correct any errors in such data prior to the issuance of Final Settlement Statements. Failure to provide complete and accurate Settlement Quality Meter Data, as required by Section 10 of the ~~ISO~~CAISO Tariff and that results in an error that is discovered after issuance of Final Settlement Statements, shall be a violation of this rule.

37.5.2.2 Sanctions.

Violations under this Section 37.5.2 shall be subject to Sanction described in Section 37.11.

37.5.2.3 Disposition of Sanction Proceeds.

For purposes of redistributing collected ~~penalties~~meter adjustments, any amounts collected under this provision shall be applied first to those parties affected by the conduct. Any excess amounts shall be disposed of as set forth in Section 37.9.4.

37.6 Provide Information Required by ~~ISO~~CAISO Tariff.

37.6.1 Required Information Generally.

37.6.1.1 Expected Conduct.

Except as provided below in Section 37.6.4 (Review by FERC), all information that is required to be submitted to the ~~ISO~~CAISO under the ~~ISO~~CAISO Tariff, ~~ISO~~CAISO ~~protocols~~Business Practice Manuals, or jurisdictional contracts must be submitted in a complete, accurate, and timely manner. Market Participants must comply with requests for information or data by the ~~ISO~~CAISO authorized under the ~~ISO~~CAISO Tariff, including timelines specified in the ~~ISO~~CAISO Tariff for submitting ~~Schedules~~ Bids and other information.

37.6.1.2 Sanctions.

Except as otherwise provided below, in Section 37.6.2 and Section 37.6.3, a violation of this rule is subject to a penalty of $500 for each day that the required information is late.

37.6.2 Investigation Information.

37.6.2.1 Expected Conduct.

Except as provided below in Section 37.6.4 (Review by FERC), Market Participants must submit timely information in response to a written request by the ~~ISO~~CAISO for information reasonably necessary to conduct an investigation authorized by the ~~ISO~~CAISO Tariff.

37.6.2.2 Sanctions.

The Sanction for a violation of Section 37.6.2 shall be as follows: for the first violation in a rolling 12-month period, $1000/day; for the second violation in a rolling 12-month period, $2000/day; for the third and subsequent violations in a rolling 12-month period, $5000/day. For purposes of this subsection, a violation shall be each failure to provide a full response to a written request and the Sanction shall be determined from the date that the response was due until a full response to the request is received.

37.6.3 Audit Materials.

37.6.3.1 Expected Conduct.

Except as provided below in Section 37.6.4 (Review by FERC), Market Participants shall comply with the ~~ISO~~CAISO's audit and/or test procedures, and further shall perform and timely submit an annual self-audit as required under the ~~ISO~~CAISO Tariff.

37.6.3.2 Sanctions.

For failure to submit an annual Scheduling Coordinator Self Audit report, the Sanction shall be $1000/day until such report is received by the ~~ISO~~CAISO. For all other violations of this rule the Sanctions shall be as follows: for the first violation in a rolling 12-month period, $1000/day; for the second violation in a rolling 12-month period, $2000/day; for the third and subsequent violations in a rolling 12-month period, $5000/day. For purposes of this subsection, a “violation” shall be each failure to provide all information required under the audit or test, from the date that the information was due until all required information is received by the ~~ISO~~CAISO.

37.6.4 Review by FERC.

A Market Participant who objects to an information, audit or test obligation that is enforceable under Section 37.6.1, Section 37.6.2 or Section 37.6.3 above shall have the right immediately (and in all events, no later than the due date for the information) to seek review of the obligation with FERC. In the event that such review is sought, the time for submitting the response or other information to the ~~ISO~~CAISO shall be tolled until FERC resolves the issue.

37.7 No Market Manipulation.

37.7.1 Market Manipulation Generally.

37.7.1.1 Expected Conduct.

Actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products are prohibited. Actions or transactions by a Market Participant that are explicitly contemplated in the ~~ISO~~CAISO Tariff or are undertaken at the direction of the ~~ISO~~CAISO are not in violation of this Rule of Conduct.

37.7.1.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.2 Wash Trades.

37.7.2.1 Expected Conduct.

Market Participants shall not engage in pre-arranged offsetting trades of the same product among the same parties, which involve no economic risk and no net change in beneficial ownership (sometimes called "wash trades").

37.7.2.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.3 False Information.

37.7.3.1 Expected Conduct.

A Market Participant shall not engage in transactions predicated on submitting false information to transmission providers or other entities responsible for operation of the transmission grid (such as inaccurate load or generation data; or ~~scheduling~~ submitting Bids for non-firm service or products sold as firm), unless the Market Participant exercised due diligence to prevent such occurrences.

37.7.3.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.4 Artificial Congestion.

37.7.4.1 Expected Conduct.

A Market Participant shall not engage in transactions in which it first creates artificial congestion and then purports to relieve such artificial congestion (unless the Market Participant exercised due diligence to prevent such an occurrence).

37.7.4.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.5 Collusion.

37.7.5.1 Expected Conduct.

Market Participants shall not engage in collusion with another party for the purpose of manipulating market prices, market conditions, or market rules for electric energy or electricity products.

37.7.5.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.8 Process for Investigation and Enforcement.

37.8.1 Purpose; Scope.

The provisions of this Section 37.8 set forth the procedures by which the Market Monitoring Unit will independently investigate potential violations of the Rules of Conduct and administer enforcement activities. Except as hereinafter provided, and except as provided in Section 37.2.5 and Section 37.4.4, the provisions of this section apply to the Rules of Conduct set forth in Sections 37.2 through 37.7.

37.8.2 Referrals to FERC.

Section 37.7 shall be enforced by FERC, in accordance with FERC's rules and procedures. The Market Monitoring Unit shall refer to FERC and its staff all matters in which it has formed a reasonable belief that a violation of Section 37.7 may have occurred. Although Sections 37.2 through 37.6 will generally be enforced by the Market Monitoring Unit, the Market Monitoring Unit shall refer to FERC any matter for which the particular circumstances preclude the objective determination of a Rules of Conduct violation, and shall refer to FERC any Sanction that it believes should be modified in accordance with Sections 37.2.5, 37.4.4, or 37.9.1. The time limitation contained in Section 37.10.1 to assess a Sanction under this Protocol shall be determined as of the date that a Sanction is initially assessed by the ~~ISO~~CAISO, excluding the time required for FERC to investigate a potential Rules of Conduct violation and/or determine a Sanction in accordance with this section, Sections 37.2.5, 37.4.4, or 37.9.1.

37.8.3 Investigation.

The Market Monitoring Unit shall conduct a reasonable investigation seeking available facts, data, and other information relevant to the potential Rules of Conduct violation.

37.8.4 Notice.

The Market Monitoring Unit shall provide notice of the investigation in sufficient detail to allow for a meaningful response to the Scheduling Coordinator and, as limited below, to all Market Participants the Scheduling Coordinator represents that are the subject(s) of the investigation. The Market Monitoring Unit shall contact the Market Participant(s) that may be involved, so long as the ~~ISO~~CAISO has sufficient objective information to identify and verify the role of the Market Participant(s) in the potential Rules of Conduct violation. Such Market Participant(s) will likely have an existing contractual relationship with the ~~ISO~~CAISO (e.g., UDC, MSS, ~~ISO~~CAISO Metered Entity, Participating Transmission Owner, Participating Generator, or Participating Load).

37.8.5 Opportunity to Present Evidence.

The Market Monitoring Unit shall provide an opportunity to the Market Participant(s) that are the subject(s) of the investigation to present any issues of fact or other information relevant to the potential Rules of Conduct violation being investigated. The Market Monitoring Unit shall consider all such information or data presented.

37.8.6 Results of Investigation.

The Market Monitoring Unit shall notify the Market Participant(s) that are the subject(s) of the investigation of the results of the investigation. The Market Participant(s) shall have 30 days to respond to the findings of the Market Monitoring Unit before the Market Monitoring Unit makes a determination of whether a Sanction is required by this ~~ISO~~CAISO Tariff.

37.8.7 Statement of Findings and Conclusions.

Where the investigation results in a Sanction, the Market Monitoring Unit shall state its findings and conclusions in writing, and will make such writing available to the Scheduling Coordinator and, as provided in Section 37.8.4, to the Market Participant(s) that are the subject(s) of the investigation.

37.8.8 Officer Representative.

Where an investigation results in a Sanction by the Market Monitoring Unit, the Market Monitoring Unit shall direct its notice of such result to a responsible representative of the Scheduling Coordinator and, as provided in Section 37.8.4, to the Market Participant(s) that are the subject(s) of the investigation at the officer level.

37.8.9 Record of Investigation.

Where an investigation results in a Sanction, the Market Monitoring Unit will maintain a record of the investigation until its decision has been finally reviewed, if review is sought, or until the period for seeking review has expired.

37.8.10 Review of Determination.

A Market Participant that receives a Sanction may obtain immediate review of the Market Monitoring Unit's determination by directly appealing to FERC, in accordance with FERC's rules and procedures. In such case, the applicable Scheduling Coordinator shall also dispute the Preliminary Settlement Statement containing the financial penalty, in accordance with Section 11 of the ~~ISO~~CAISO Tariff. The Preliminary Settlement Statement dispute and appeal to FERC must be made in accordance with the timeline for raising disputes specified in Section 11.29.8.2 ~~11.7.2~~ of the ~~ISO~~CAISO Tariff. The penalty will be tolled until FERC renders its decision on the appeal. The disposition by FERC of such appeal shall be final, and no separate dispute of such Sanction may be initiated under Section 13 of the ~~ISO~~CAISO Tariff, except as provided in Section 37.9.3.4. For the purpose of applying the time limitations set forth in Section 37.10.1, a sanction will be considered assessed when it is included on a Preliminary Settlement Statement, whether or not the ~~ISO~~CAISO accepts a Scheduling Coordinator's dispute of such Preliminary Settlement Statement pending resolution of an appeal to FERC in accordance with this section or Section 37.9.3.3.

37.9 Administration of Sanctions

37.9.1 Assessment; Waivers and Adjustments. Penalty amounts for violation of these Rules of Conduct shall be calculated as specified in Section 37.2 through Section 37.7. A Sanction specified in this Section 37 may be modified by FERC when it determines that such adjustment is just and reasonable. The ~~ISO~~CAISO may make a recommendation to FERC to modify a Sanction. An adjustment generally shall be deemed appropriate if the prescribed Sanction appears to be insufficient to deter the prohibited behavior, or if the circumstances suggest that the violation was inadvertent, unintentional, or some other mitigating circumstances exist.

37.9.2 Excuse.

The following circumstances shall excuse a violation of a Rule of Conduct under the terms of this ~~ISO~~CAISO Tariff:

37.9.2.1 Uncontrollable Force.

No failure by a Market Participant to satisfy the Rules of Conduct shall be subject to penalty to the extent and for the period that the Market Participant's inability to satisfy the Rules of Conduct is caused by an event or condition of Uncontrollable Force affecting the Market Participant; provided that the Market Participant gives notice to the ~~ISO~~CAISO of the event or condition of Uncontrollable Force as promptly as possible after it knows of the event or condition and makes all reasonable efforts to cure, mitigate, or remedy the effects of the event or condition.

37.9.2.2 Safety, Licensing, or Other Requirements.

Failure by a Market Participant to perform its obligations shall not be subject to penalty if the Market Participant is able to demonstrate that it was acting in accordance with Section 4.2.1 of the ~~ISO~~CAISO

Tariff.

37.9.2.3 Emergencies.

Failure by a Market Participant to perform its obligations may not be subject to penalty if the Market Participant is able to demonstrate that it was acting in good faith and consistent with Good Utility Practice to preserve System Reliability in a System Emergency, unless contrary to a~~n~~ ~~ISO~~CAISO operating order.

37.9.2.4 Conflicting Directives.

To the extent that any action or omission by a Market Participant is specifically required by a FERC Order or ~~ISO~~CAISO operating order, the Market Participant may not be subject to penalty for that act or omission.

37.9.3 Settlement.

37.9.3.1 Settlement Statements.

The ~~ISO~~CAISO will administer any penalties issued under this ~~Enforcement Protocol~~Section 37 through Preliminary Settlement Statements, and Final Settlement Statements issued to the responsible Scheduling Coordinator by the ~~ISO~~CAISO. Before invoicing a financial penalty through the Settlement process, the ~~ISO~~CAISO will provide a description of the penalty to the responsible Scheduling Coordinator and all Market Participants the Scheduling Coordinator represents that are liable for the penalty, when the ~~ISO~~CAISO has sufficient objective information to identify and verify responsibility of such Market Participants. The ~~ISO~~CAISO shall specify whether such penalty is modified pursuant to Section 37.2.5, Section 37.4.4 or Section 37.9.1. The description shall include the identity of the Market Participant that committed the violation and the amount of the penalty. Where FERC has determined the Sanction, the ~~ISO~~CAISO will provide such of the above information as is provided to it by FERC. The ~~ISO~~CAISO also may publish this information under the ~~ISO~~CAISO ~~Home Page~~Website after Final Settlement Statements are issued.

37.9.3.2 Payment.

Except as provided in Section 37.2.5, Section 37.4.4, Section 37.8.10 or Section 37.9.3.3 below, the Scheduling Coordinator shall be obligated to pay all penalty amounts reflected on the Preliminary and Final Settlement Statements to the ~~ISO~~CAISO pursuant to the ~~ISO~~CAISO's Settlement process, as set forth in Section 11 of the ~~ISO~~CAISO Tariff.

37.9.3.3 Other Responsible Party.

Where a party or parties other than the Scheduling Coordinator is responsible for the conduct giving rise to a penalty reflected on a Preliminary or Final Settlement Statement, and where the Scheduling Coordinator bears no responsibility for the conduct, such other party or parties ultimately shall be liable for the penalty. Under such circumstances, the Scheduling Coordinator shall use reasonable efforts to obtain payment of the penalty from the responsible party(ies) and to remit such payment to the ~~ISO~~CAISO in the ordinary course of the settlement process. In the event that the responsible party(ies) wish to dispute the penalty, or the Scheduling Coordinator otherwise is unable to obtain payment from the responsible parties, the Scheduling Coordinator shall notify the ~~ISO~~CAISO and dispute the Preliminary Settlement Statement. The ~~ISO~~CAISO promptly shall notify FERC. If the ~~ISO~~CAISO finds that a Market Participant separate from the Scheduling Coordinator that is unable to obtain payment from the responsible party(ies) is solely responsible for a violation, the Scheduling Coordinator that is unable to obtain payment may net its payment of its Invoice amount by the amount of the penalty in question. The ~~ISO~~CAISO may refuse to offer further service to any responsible party that fails to pay a penalty, unless excused under the terms of the Tariff~~ or this Enforcement Protocol~~, by providing notice of such refusal to the Scheduling Coordinator. Following such notice, the Scheduling Coordinator shall be liable for any subsequent penalties assessed on account of such responsible party.

37.9.3.4 Dispute of FERC Sanctions.

The right that a Market Participant may otherwise have under the CAISO Tariff ~~or this Enforcement Protocol~~ to dispute a penalty that has been determined by FERC shall be limited to a claim that the ~~ISO~~CAISO failed properly to implement the penalty or other Sanction ordered by FERC, except as provided by Section 37.2.5 and Section 37.4.4.

37.9.4 Disposition of Proceeds.

The ~~ISO~~CAISO shall collect penalties assessed pursuant to this Section 37.9 and deposit such amounts in an interest bearing trust account. After the end of each calendar year, the ~~ISO~~CAISO shall distribute the penalty amounts together with interest earned through payments to Scheduling Coordinators as provided herein. For the purpose of this Section 37.9.4, "eligible Market Participants" shall be those Market Participants that were not assessed a financial penalty pursuant to this Section 37 during the calendar year.

Each Scheduling Coordinator that paid GMC during the calendar year will identify, in a manner to be specified by the ~~ISO~~CAISO, the amount of GMC paid by each Market Participant for whom that Scheduling Coordinator provided service during that calendar year. The total amount assigned to all Market Participants served by that Scheduling Coordinator in such calendar year (including the Scheduling Coordinator itself for services provided on its own behalf), shall equal the total GMC paid by that Scheduling Coordinator.

The ~~ISO~~CAISO will calculate the payment due each Scheduling Coordinator based on the lesser of the GMC actually paid by all eligible Market Participants represented by that Scheduling Coordinator, or the product of a) the amount in the trust account, including interest, and b) the ratio of the GMC paid by each Scheduling Coordinator ~~on behalf of~~ for eligible Market Participants, to the total of such amounts paid by all Scheduling Coordinators. Each Scheduling Coordinator is responsible for distributing payments to the eligible Market Participants it represented in proportion to GMC collected from each eligible Market Participant.

Prior to allocating the penalty proceeds, the ~~ISO~~CAISO will obtain FERC's approval of its determination of eligible Market Participants and their respective shares of the trust account proceeds. If the total amount in the trust account to be so allocated exceeds the total GMC obligation of all eligible Market Participants, then such excess shall be treated in accordance with Section 11.8.5.3(b).

37.10 Miscellaneous.

37.10.1 Time Limitation.

An investigation of events potentially subject to Sanction under this Section 37 must be commenced within 90 days of discovery of the events. Sanctions may be assessed under this Section 37 up to one year after discovery of the events constituting the violation, but no later than three years after the date of the violation. Nothing in this section shall limit the rights or liabilities of any party under any other provision of applicable laws, regulations or tariff provisions.

37.10.2 No Limitation on Other Rights.

Nothing contained in this Section 37 shall limit the ability of the ~~ISO~~CAISO to collect information from Market Participants or to establish new provisions pursuant to Section 15 of the ~~ISO~~CAISO Tariff.

37.11 Method for Calculating Penalties.

37.11.1~~.~~ Method for Calculating Inaccurate Meter Data Penalty.

There is no Sanction for the submission of inaccurate meter data used for Preliminary Settlement Statements. However, an error in submitted meter data that is discovered after issuance of Final Settlement Statements constitutes a Rule of Conduct violation. The level of the Sanction depends on whether the Scheduling Coordinator or the ~~ISO~~CAISO discovered the error. An increased penalty will apply for errors that are discovered by the ~~ISO~~CAISO.

Table A1 below shows how the level of the Sanction depends on the following factors: whether or not the Scheduling Coordinator finds the error; whether or not the Scheduling Coordinator owes the market, and whether or not the ~~ISO~~CAISO reruns settlement of the market. If the ~~ISO~~CAISO reruns the market, then settlement to all Scheduling Coordinators is recalculated, and the impact of such reruns on charges assessed will be considered. A penalty charge equal to 30% of the estimated value of the Energy error will apply if the Scheduling Coordinator discovers the error, or 75% of the estimated value of the Energy error if the ~~ISO~~CAISO discovers the error. Penalty assessment and disposition of penalty proceeds will be administered as described in Section 37.9.1 and Section 37.9.4 respectively. A Sanction will not be imposed unless such Sanction is more than $1,000 for at least one Trading Day during the period for which there was incomplete or inaccurate meter data.

Table A1 – Calculation of Inaccurate Meter Data Penalty When There Is A Market Rerun

Case	Does SC Owe Market?	
Case 1: SC Identifies Inaccurate Meter Data	Yes	Charge = (MWh x Hourly ~~Ex Post Price~~LMP[1]) x 0.30
Case 1: SC Identifies Inaccurate Meter Data	No	Charge = (MWh x Hourly ~~Ex Post Price[1]~~LMP) x 0.30
Case 2: ~~ISO~~CAISO Identifies Inaccurate Meter Data	Yes	Charge = (MWh x Hourly ~~Ex Post Price~~LMP[1]) x 0.75

Case 2: ~~ISO~~CAISO Identifies Inaccurate Meter Data	No	Charge = (MWh x Hourly ~~Ex Post Price~~LMP[1]) x 0.75

Note to Table A1:

The applicable price will be the greater of the Hourly ~~Ex Post Price~~LMP or $10/MWh. The Hourly ~~Ex Post Price~~ LMP used will be the value posted ~~under the ISO Home Page~~on OASIS for each Trading Hour of the applicable Trading Day.

2. Method for Calculating Inaccurate Meter Data Penalty When The Market Is Not Re-Run.

If the Market is not re-run, for cases of inaccurate meter data, Table A2 will be used to determine and allocate the penalty proceeds. This method approximates the financial impact on the market; however, it does not completely reflect all the settlement consequences of inaccurately submitted meter data. This will be considered a market adjustment. The approximated value of the inaccurate meter data in question will be calculated and returned to the Market based on the average of the pro rata share of Unaccounted For Energy (UFE) charged in the UDC territory during the period of the inaccurate meter data event. The 30% or 75% penalty will be distributed as discussed in Section 37.9.4. For cases where the market is not re-run and the Scheduling Coordinator does not owe the market, then no market adjustment will be performed.

TABLE A2- Calculation Of Inaccurate Meter Data Penalty When There Is No Market Re-Run

Case	Does SC Owe Market?	~~ISO~~CAISO does not perform a market settlement re-run
Case 1: SC Identifies Inaccurate Meter Data	Yes	Market Adjustment = (MWh x Hourly LMP~~Ex Post Price~~[~~1~~]) Penalty = (MWh x Hourly LMP~~Ex Post Price~~[~~1~~]) x 0.30
Case 1: SC Identifies Inaccurate Meter Data	No	No Market Adjustment will be made Penalty = (MWh x Hourly LMP~~Ex Post Price~~[~~1~~]) x 0.30

Case 2: ~~ISO~~CAISO Identifies Inaccurate Meter Data	Yes	Market Adjustment = (MWh x Hourly LMP~~Ex Post Price[1]~~) Penalty = (MWh x Hourly LMP~~Ex Post Price[1]~~) x 0.75
Case 2: ~~ISO~~CAISO Identifies Inaccurate Meter Data	No	No Market Adjustment will be made Penalty = (MWh x Hourly LMP~~Ex Post Price[1]~~) x 0.75

Notes to Table A2:

The applicable price will be the greater of the Hourly LMP ~~Ex Post Price~~ or $10/MWh. The Hourly LMP~~Ex Post Price~~ used will be the value posted ~~under the ISO Home Page~~on OASIS for each Trading Hour of the applicable Trading Day.

A Sanction will be imposed only if the Sanction is more than $1,000 for at least one Trading Day during the period for which there was incomplete or inaccurate meter data.

If the error is to the detriment of the responsible Scheduling Coordinator (e.g., under-reported generation or over-reported load), and the ~~ISO~~CAISO does not rerun the market, then no correction will be made, representing an implicit penalty of 100% of the value of the Energy. If the market is rerun after the error is corrected, then the Scheduling Coordinator will be given credit for the additional Energy through the normal Settlement process. If the Scheduling Coordinator is paid for an error due to a market rerun, then a Sanction will be assessed to assure that market reruns do not diminish the incentive to correct such errors. This Sanction would be 30% of the Energy value of the error if the Scheduling Coordinator discovers the error, or 75% estimated value of the error if the ~~ISO~~CAISO discovers the error.

If the error is to the detriment of the market, then a charge equal to 30% or 75% of the estimated value of the error, as appropriate, will be added to the charge for the Energy. If there is no market rerun, then the cost of Energy supplied by the ~~ISO~~CAISO (and inappropriately charged to the market as Unaccounted for Energy) must be recovered as well, and the charge will be equal to 130% or 175% of the estimated value of the error, as appropriate.

~~**ARTICLE IV – MARKET MONITORING AND MARKET POWER MITIGATION**~~

38 MARKET MONITORING.

38.1 Objectives and Scope.

This Section sets forth the ~~workplan and, where applicable, the rules~~framework under which the ~~ISO~~CAISO Department of Market ~~Analysis~~ Monitoring and ~~ISO~~CAISO Market Surveillance Committee will monitor the ~~ISO~~CAISO Markets to identify abuses of market power, to ensure to the extent possible the efficient working of the ~~ISO~~CAISO Markets immediately upon commencement of their operation, and to provide for their protection from abuses of market power in both the short term and the long term, and from other abuses that have the potential to undermine their effective functioning or overall efficiency in accordance with Section 38.1.1 of the ~~ISO~~CAISO Tariff. Such monitoring activities will be carried out by, among other ~~ISO~~CAISO departments, the ~~ISO~~CAISO Department of Market Monitoring ~~Analysis~~ and the ~~ISO~~CAISO Market Surveillance Committee to be established and to operate under the terms of this ~~Protocol~~CAISO Tariff, as set forth below. ~~These protocols~~This Section provides a general framework for the operation of the Department of Market Monitoring ~~Analysis~~ and the Market Surveillance Committee and are not intended to limit the activities or remedies available to these entities or to the ~~ISO~~CAISO as a whole elsewhere in the ~~ISO~~CAISO Tariff or otherwise under law.

38.1.1 Market Surveillance: Changes to Operating Rules and ~~Protocols~~Procedures.

The ~~ISO~~CAISO shall keep the operation of the markets that it administers under review to determine whether changes in its operating rules, Business Practice Manuals, or ~~ISO~~CAISO ~~Protocols~~ Tariff would improve the efficiency of those markets or prevent the exercise of market power by any Market Participant; and it shall institute necessary changes in accordance with this Section 38. ~~The details of the ISO Market Monitoring and Information Protocol are set forth in Appendix P.~~

38.1.2 Reporting Requirements.

This Section of the ~~ISO~~CAISO Tariff sets forth the information dissemination, publication and reporting activities and other means of providing information that the ~~ISO~~CAISO generally undertakes to meet its reporting requirements to regulatory agencies, Market Participants and others. The goal of the reporting provisions is to adequately inform regulatory agencies, law enforcement agencies, policymakers, Market

Participants and others of the state of the ~~ISO~~CAISO Markets, especially their competitiveness and efficiency. This function is designed to facilitate efficient corrective actions to be taken by the appropriate body or bodies when required.

38.2 Practices Subject to Scrutiny – General.

The Department of Market ~~Analysis~~ Monitoring shall monitor the activities of Market Participants that affect the operation of the ~~ISO~~CAISO Markets and that provide indications of the phenomena set forth below in this Section 38.2 and will monitor for violations of the behavior market rules specified in Section 37 and any FERC orders establishing market behavior rules for Market Participants. Any corrective actions taken in response to potential violations of market behavior rules shall be made consistent with Section 37 and/or the applicable FERC orders. Where appropriate, it will take such further action as it considers necessary under Section 38.4.

38.2.1 Abuse of Reliability Must-Run Unit Status.

Where Generating Units are determined by the ~~ISO~~CAISO to be Reliability Must-Run Units, circumstances that indicate that such Generating Units are being operated in a manner that will adversely affect the competitive nature and efficient workings of the ~~ISO~~CAISO Markets.

38.2.2 ~~ISO~~CAISO and Other Market Design Flaws.

Design flaws and inefficiencies in the ~~ISO~~CAISO Tariff, ~~ISO Protocols~~ Business Practices Manuals, and ~~o~~Operating ~~perational~~ Procedures~~rules and procedures of the ISO~~, including the potential for problems between the ~~ISO~~CAISO and other independent power markets or exchanges insofar as they affect the ~~ISO~~CAISO Markets.

38.2.3 Market Structure Flaws.

With respect to flaws in the overall structure of the California energy markets that may reveal undue concentrations of market power in Generation or other structural flaws, the Department of Market ~~Analysis~~ Monitoring shall provide such information or evidence of such flaws and such analysis as it may conduct to the ~~ISO~~CAISO CEO and/or to the ~~ISO~~CAISO Governing Board, subject to due protections of confidential or commercially sensitive information. After due internal consultation, if instructed by any of such ~~ISO~~CAISO institutions or persons, the Department of Market Monitoring ~~Analysis~~ shall also provide such information or evidence to the Market Surveillance Committee, the appropriate regulatory and antitrust enforcement agency or agencies, subject to due protections of confidential or commercially sensitive information. The Department of Market Monitoring ~~Analysis~~ shall, at the direction of the ~~ISO~~CAISO CEO and/or the ~~ISO~~CAISO Governing Board, or their designee, provide such other evidence, views, analyses or testimony as may be appropriate or required and as it is reasonably capable of providing to assist the investigations of such agencies.

38.3 Scrutiny of Market Participant Changes Potentially Affecting Market Structure.

The Department of Market Monitoring ~~Analysis~~ may undertake the following measures to monitor the special circumstances that may affect the operation of the ~~ISO~~CAISO Markets due to corporate reorganizations including bankruptcies or changes in affiliate relationships and may recommend corrective actions as provided in Section 38.4.

38.3.1 Exercises of Horizontal Market Power.

The Department of Market Monitoring ~~Analysis~~ may analyze the impact of changes in market structure on the ability of Market Participants to exercise short-term horizontal market power.

38.4 Response Action by ~~ISO~~CAISO.

38.4.1 Corrective Actions.

Where the monitoring activities or any consequent investigations carried out by the Department of Market Monitoring ~~Analysis~~ pursuant to Section 38.2 and Appendix P.1 reveal a significant possibility of the presence of or potential for exercises of market power that would adversely affect the operation of the ~~ISO~~CAISO Markets, or other markets interconnected or interdependent on the ~~ISO~~CAISO Markets, the Department of Market ~~Analysis~~ Monitoring shall take the appropriate measures under this section and under Appendix P to institute the corrective action most effective and appropriate for the situation or, in the case of markets interconnected to or interdependent on the ~~ISO~~CAISO Markets, the Department of Market Monitoring ~~Analysis~~ may recommend corrective actions to the appropriate regulatory agencies.

38.4.2 Further Actions.

Where the monitoring activities of or any consequent investigations carried out by the Department of Market Monitoring ~~Analysis~~ pursuant to Sections 38.2 and 38.3 reveal that activities or behavior of Market Participants in the ~~ISO~~CAISO Markets have the effect of, or potential for, undermining the efficiency, workability or reliability of the ~~ISO~~CAISO Markets to give or to serve such Market Participants an unfair competitive advantage over other Market Participants, the Department of Market Monitoring ~~Analysis~~ shall fully investigate and analyze the effect of such activities or behavior and make recommendations to the ~~ISO~~CAISO CEO and the ~~ISO~~CAISO Governing Board for further action by the ~~ISO~~CAISO or, where necessary, by other entities. The Department of Market Monitoring ~~Analysis~~ may, where appropriate, make specific recommendations to the ~~ISO~~CAISO CEO and to the ~~ISO~~CAISO Governing Board for amendment to rules and protocols under its control, or for changes to the structure of the ~~ISO~~CAISO Markets, and the Department of Market Monitoring ~~Analysis~~ may recommend actions, including fines or suspensions, against specific entities in order to deter such activities or behavior.

38.4.3 Adverse Effects of Transition Mechanisms.

Should the monitoring and analysis conducted ~~under Appendix P~~ reveal significant adverse effects of transition mechanisms on competition in or the efficient operation of the ~~ISO~~CAISO Markets, the Department of Market Monitoring ~~Analysis~~ shall examine and fully assess the efficacy of all possible measures that may be taken by the ~~ISO~~CAISO, in order to prevent or to mitigate such adverse effects. The Department of Market Monitoring ~~Analysis~~ shall make such recommendations to the CEO of the ~~ISO~~CAISO and to the ~~ISO~~CAISO Governing Board as it considers appropriate for action by the ~~ISO~~CAISO and/or for referral to regulatory or law enforcement agencies. Such proposed measures may include, but shall not be limited to the following:

38.4.3.1 the use of direct ~~bid~~ Bid caps as a mechanism to prevent or mitigate artificially high Market Clearing Prices caused by abuses of market power;

38.4.3.2 the use of contracts for differences for eliminating the incentive for Generators to bid ~~ISO~~CAISO prices to artificially high levels enabled by the presence of market power;

38.4.3.3 calling upon Reliability Must-Run Units to operate; and to modify Reliability Must-Run Contracts;

38.4.3.4 ~~bid~~ Bid floors to prevent or mitigate the possible exercise of below-cost bidding or predatory pricing.

In the event that the ~~ISO~~CAISO Governing Board adopts, and where necessary obtains regulatory approval for, any measure proposed pursuant to Section 38.4.3, the Department of Market Monitoring ~~Analysis~~ shall monitor the implementation and effect of such measure on the state of the ~~ISO~~CAISO

Markets and shall periodically report on them to the CEO and the ~~ISO~~CAISO Governing Board.

39 Market Power Mitigation Procedures

~~**39.1 Damage Control Bid Cap.**~~

~~Notwithstanding any other provision of this ISO Tariff, Damage Control Bid Cap provisions of Sections 39.2 and 39.3 shall apply to the ISO's Energy and Ancillary Service capacity markets.~~

39.1 ~~**MMIP 1**~~ These CAISO market power mitigation measures ("Mitigation Measures") are intended to provide the means for the CAISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the CAISO ~~Real Time~~ Markets while avoiding unnecessary interference with competitive price signals. These Mitigation Measures are intended to minimize interference with an open and competitive market, and thus to permit, to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the Mitigation Measures authorize the mitigation only of specific conduct ~~that exceeds well-defined thresholds~~identified through explicit procedures specified below. In addition, the CAISO shall monitor the markets it administers for conduct that it determines constitutes an abuse of market power but ~~does not trigger the thresholds~~is not addressed by the market power mitigation procedures specified below ~~for the imposition of mitigation measures by the ISO~~. If the CAISO identifies any such conduct~~, and in particular conduct exceeding the thresholds for presumptive market effects specified below~~, it shall make a filing under Section 205 of the Federal Power Act, 16 U.S.C. § 824d, with FERC requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the CAISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the CAISO's justification for imposing that mitigation measure.

~~**39.2 Maximum Bid Level.**~~

~~The maximum bid level shall be $250/MWh. Market Participants may submit bids above $250/MWh, however, any accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost justification and refund.~~

39.2 Conditions for the Imposition of Mitigation Measures

39.2.1 In general, the CAISO shall consider a Market Participant's conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the Market Participant in the absence of market power. The categories of conduct that are inconsistent with competitive conduct include, but may not be limited to, the four categories of conduct specified in Section 39.3 below.

39.3 ~~MMIP 2.4~~ Categories of Conduct that May Warrant Mitigation

39.3.1 **~~MMIP2.4.1~~** Mitigation Measures may be applied to bidding, scheduling or operation of an Electric Facility or as specified in Section 39.3.1. The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or generally the outcome of the ~~ISO~~ CAISO ~~Real Time~~ Markets if exercised from a position of market power. Accordingly, the ~~ISO~~ CAISO shall monitor the ~~ISO~~ CAISO Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

(1) Physical withholding of an Electric Facility, in whole or in part, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving a~~n~~ ~~ISO~~ CAISO Market. Such withholding may include, but not be limited to: (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become totally or partially unavailable, (ii) refusing to offer B~~b~~ids ~~or schedules~~ for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, (iii) declining ~~real-time~~ B~~b~~ids called upon by the ~~ISO~~ CAISO (unless the ~~ISO~~ CAISO is informed in accordance with established procedures that the relevant resource for which the B~~b~~id is submitted has undergone a forced outage or derate), or (iv) operating a Generating Unit in ~~real time~~Real-Time to produce an output level that is less than the ~~ISO~~ Dispatch I~~i~~nstruction.

(2) Economic withholding of an Electric Facility, that is, submitting B~~b~~ids for an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) so that: (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the B~~b~~ids will set ~~a Market Clearing Price~~LMPs.

(3) Uneconomic production from an Electric Facility that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint.

(4) Bidding practices that are contrary to the principle of price convergence between Day-Ahead and Real-Time markets.

39.3.2 ~~MMIP 2.4.2~~ Mitigation Measures may also be imposed to mitigate the market effects of a rule, standard, procedure, design feature, or known software imperfection of a~~n ISO~~ CAISO Market that allows a Market Participant to manipulate market prices or otherwise impair the efficient operation of that market, pending the revision of such rule, standard, procedure design feature, or software defect to preclude such manipulation of prices or impairment of efficiency.

39.3.3 ~~MMIP 2.4.3~~ Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than a~~n ISO~~ CAISO Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

39.3.4 ~~MMIP 2.4.4~~ The ~~ISO~~ CAISO shall monitor ~~ISO~~ CAISO Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices in a~~n ISO~~ CAISO Market or other payments. The ~~ISO~~ CAISO shall ~~: (i)~~ seek to amend the foregoing list as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the ~~ISO~~ CAISO Markets.

39.4 ~~MMIP Appendix A- Section 4.3~~Sanctions for Physical Withholding

The CAISO may report a Market Participant the CAISO determines to have engaged in physical withholding, including providing the CAISO false information regarding derating or outage of an Electric Facility, to the Federal Energy Regulatory Commission in accordance with Section 9.3.10.5 of the CAISO Tariff. In addition, a Market Participant that fails to operate a Generating Unit in conformance with CAISO Dispatch Instructions shall be subject to the penalties set forth in Section 11.23 ~~11.2.4.1.2~~ of the CAISO Tariff.

39.5 ~~MMIP Appendix A Section 5~~ FERC-Ordered Measures

In addition to any mitigation measures specified above, the CAISO shall administer, and apply when appropriate in accordance with their terms, such other mitigation measures as it may be directed to implement by order of the FERC.

39.6 Rules Limiting Certain Energy, ~~and~~ Ancillary Services, And Residual Unit Commitment Bids.

39.6.1 ~~39.1~~ Maximum Bid Prices~~Damage Control Bid Cap~~.

Notwithstanding any other provision of this ~~ISO~~ CAISO Tariff, maximum Bid price ~~Damage Control Bid Cap~~ provisions of Section~~s~~ 39~~.2 and 39.3~~ shall apply to limit, ~~the ISO's~~ Energy Bids, RUC Availability Bids, and Ancillary Service Bids as specified below ~~capacity markets~~.

39.6.1.1 ~~39.2~~ Maximum ~~Bid Level.~~Price for Energy Bids

For the twelve (12) months following the effective date of this Section, the maximum Energy Bid prices shall be $500/MWh. After the twelfth month following the effective date of this Section, the maximum Energy Bid price shall be $750/MWh. After the twenty-fourth month following the effective date of this Section, the maximum Energy Bid price shall be $1,000/MWh.

~~The maximum bid level shall be $250/MWh. Market Participants may submit bids above $250/MWh, however, any accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost-justification and refund.~~

39.6.1.2 Maximum RUC Availability Bid Prices

The maximum RUC Availability Bid price shall be $250/MW/h.

39.6.1.3 Maximum Ancillary Services Bid Prices

The maximum level for Ancillary Services Bid prices shall be $250/MWh.

39.6.1.4 ~~39.3~~ Minimum Bid Price for~~Negative Decremental~~ Energy Bids.

~~Negative decremental~~ Energy B~~b~~ids into the ~~ISO~~ CAISO Markets less than -$30/MWh ~~(minus thirty dollars per MWh)~~ are ~~shall~~ not ~~be~~ eligible to set any LMP. ~~Market Clearing Price and. if Dispatched, shall be paid as bid. If the ISO Dispatches a bid below -$30/MWh, the supplier must submit a detailed breakdown of the component costs justifying the bid to the ISO and to the Federal Energy Regulatory Commission no later than seven (7) days after the end of the month in which the bid was submitted. The ISO will treat such information as confidential and will apply the procedures in Section 20.4 of this ISO Tariff with regard to requests for disclosure of such information. The ISO shall pay suppliers for amounts in excess of $-30/MWh after those amounts have been justified.~~

39.6.1.5 Minimum Bid Price for Ancillary and RUC Bids.

Ancillary Service Bids and RUC Availability Bids submitted into CAISO markets must have Bid prices not less than $0/MW/h.

39.7 Local Market Power Mitigation for Energy Bids. Local market power mitigation is based on a periodic assessment and designation of transmission constraints as competitive or non-competitive. Such periodic assessment will be performed at a minimum on an annual basis and potentially more frequently if needed due to changes in system conditions, network topology, or market performance. Any changes in constraint designations will be publicly noticed prior to making the change. Upon determination that an *ad hoc* assessment is warranted, the CAISO will notice market participants that such an assessment will be performed. The determination whether a unit is being dispatched to relieve congestion on a competitive or non-competitive transmission constraint is based on two preliminary market runs that are performed prior to the actual pricing run of the market and are described in Sections 31 and 33 for the DAM and RTM, respectively.

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 Independent Entity charged with calculating the Default Energy Bid. 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.

39.7.1.1 Variable Cost Option.

The Variable Cost option will calculate the Default Energy Bid as Variable Costs plus ten percent (10%). Variable Cost will be comprised of two components: Fuel Cost and Variable Operation and Maintenance Cost. The Fuel Cost portion will be calculated for each Bid segment using the Heat Rate supplied by the resource owner on file in the Master File and applicable regional natural gas price indices as specified in the Business Practice Manual. The default value for the Variable Operation and Maintenance Cost portion will be $2/MWh. Generating Units that are of the Combustion Turbine or Reciprocating Engine technology will be eligible for a default Variable Operation and Maintenance Cost of $4/MWh. Resource specific values may be negotiated with the Independent Entity charged with calculating the Default Energy Bid.

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) days. The weighted average will be calculated based on the quantities Dispatched within each segment of the Default Energy Bid curve. To qualify for the LMP Option, at least fifty percent (50%) of the MWh Dispatched over the prior ninety (90) day time period must have been unmitigated.

39.7.1.3 Negotiated Option.

The Negotiated Option is a Default Energy Bid that is derived through consultation between the Scheduling Coordinator for a Generating Unit and the CAISO or an alternative independent entity selected by the CAISO to determine an amount for its Default Energy Bid.

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.

39.7.2 Competitive Path Designation

39.7.2.1 Timing of Assessments

The CAISO will complete the first assessment of competitiveness of transmission constraints prior to the effective date of this provision. Constraint designations resulting from the first assessment will be applied in the MPM-RRD mechanism on the day this CAISO Tariff becomes effective and will not be changed until a subsequent assessment has been performed. Subsequent annual assessments will be made in each subsequent year to be effective on January 1 of the following year (beginning on January 1, 2009). The CAISO may perform additional competitive constraint assessments during the year if changes in transmission infrastructure, generation resources, or Load, in the CAISO Control Area and adjacent Control Areas suggest material changes in market conditions or if market outcomes are observed that are inconsistent with competitive market outcomes.

39.7.2.2 Criteria

A transmission constraint, will be deemed competitive if no three unaffiliated suppliers are jointly pivotal in relieving congestion on that constraint. The determination of whether or not the pivotal supplier criteria for an individual constraint are violated will be assessed using the Feasibility Index described in Section 39.7.2.4 of this CAISO Tariff. Assessment of competitiveness will be performed assuming various system conditions potentially including but not limited to season, load, planned transmission and resource outages. If an individual constraint fails the pivotal supplier criteria under any of these system conditions, the constraint will be deemed uncompetitive for the entire year under all system conditions until a subsequent assessment deems the constraint competitive. In general, a constraint may be an individual transmission line or a collection of lines that create distinct transmission constraint. For purposes of the competitive assessment, the set of constraints that will be included in the network model are those modeled along with transmission limits to be enforced in the FNM used in clearing the CAISO Markets.

39.7.2.3 Candidate Path Identification

The first assessment of competitive constraints will be determined prior to the effective date of this provision and will consider all interfaces to neighboring control areas and all inter-zonal interfaces for zones that existed prior to the effective date of this provision to be competitive. The set of candidate constraints that will be evaluated for competitiveness in the initial assessment will be limited to intra-zonal constraints for zones that existed prior to the effective date of this provision, that were managed for Congestion in Real-Time in greater than 500 hours in the 12-month period from April 1, 2006 to March 31, 2007. For the second competitive path assessment, the 12-month period of historical data would include a few months of operation before the effective date of this provision and a few months after the effective date of this provision. The Congestion frequency threshold of 500 hours for designation of competitive constraint candidates will be based on the combination of real-time intra-zonal congestion hours that pre-dated the effective date of this provision, and congestion in IFM and Real-Time markets after the effective date of this provision for the 12 months of historical data. Subsequent annual assessments will again consider all pre-existing interfaces to neighboring control areas and all inter-zonal interfaces to be competitive and will not be included in the set of candidate constraints for assessment. The set of candidate constraints will be further reduced to those remaining constraints that were congested or managed for congestion in greater than 500 hours in the prior 12 months.

39.7.2.4 Feasibility Index

The CAISO will perform a pivotal supplier test on all suppliers in the CAISO Control Area for each path to be assessed using the Feasibility Index (FI). The FI requires solving the network model having removed all internal resources of a supplier and modifying the candidate constraints of the network model such that the flow limits of the set of candidate constraints can be exceeded with a penalty imposed for excess flow. The resulting solution to the network model produces constraint flows that can be used to calculate the FI. The FI is calculated for each constraint as the proportion of the constraint limit that is exceeded to solve the FNM without the specified supplier's supply. FI values less than zero indicate the supplier is pivotal in relieving Congestion on the specified constraint. The process is repeated by removing the supply portfolio of two and three suppliers for paths with non-negative FI. If any three suppliers are jointly pivotal in relieving congestion on a candidate path, as indicated by an FI value less than zero, the candidate path will be deemed uncompetitive. Otherwise, the candidate path will be deemed competitive. The portfolio of each supplier will be based on ownership information available to the CAISO, taking into account any material transfer of sufficient length that the transfer of control could have persistent impact on the relative shares of supply within the CAISO Control Area. These transfers of control will be utilized in the assessment as provided to the CAISO by the supplier reflecting its triennial filing with FERC for market-based rate authority.

39.8 Eligibility for Bid Adder

A Scheduling Coordinator submitting Bids for Generating Units is eligible to have a Bid Adder applied to a Generating Unit for the next operating month if the criteria in Section 39.8.1 are met as determined on a monthly basis in the preceding month.

39.8.1 Bid Adder Eligibility Criteria.

To receive a Bid Adder, a Generating Unit must: (i) have a Mitigation Frequency that is greater than eighty (80) percent in the previous 12 months; (ii) have run for more than 200 hours in the previous 12 months; and (iii) must not have an contract to be a Resource Adequacy Resource for its entire net dependable capacity or be subject to an obligation to make capacity available under this CAISO Tariff. Additionally, the Scheduling Coordinator for the Generating Unit must agree to be subject to the Frequently Mitigated Unit Option for a Default Energy Bid. Run hours are those hours during which a

Generating Unit has positive metered output. During the first 12 months after the effective date of this Section, the Mitigation Frequency will be based on a rolling 12-month combination of RMR dispatches and incremental bids dispatched out of economic merit order to manage local congestion from the period prior to the effective date of this Section, which will serve as a proxy for being subject to Local Market Power Mitigation, and a Generating Unit's Local Market Power Mitigation frequency after the effective date of this Section. Generating Units that received RMR dispatches and/or incremental bids dispatched out of economic merit order to manage local Congestion in an hour prior to the effective date of this Section will have that hour counted as a mitigated hour in their Mitigation Frequency. After the first 12 months from the effective date of this Section, the Mitigation Frequency will be based entirely on a Generating Unit being mitigated under the MPM-RRD procedures in Sections 31 and 33.

39.8.2 New Generating Units.

For new Generating Units, with less than 12-months of operation, determination of eligibility for the Bid Adder will be based on data beginning with the first date the Generating Unit participated in the CAISO Markets through the end date of the period for which the Mitigation Frequency is being calculated. The 200 run hour criteria will be pro-rated for the proportion of a 12-month period that the new Generating Unit submitted effective Bids in the CAISO markets.

39.8.3 Bid Adder Values.

The value of the Bid Adder will be either: (i) a unit-specific value determined in consultation with the CAISO or an independent entity selected by the CAISO, or (ii) a default Bid Adder of $24/MWh. For Generating Units with a portion of their capacity identified as meeting an LSE's Resource Adequacy Requirements, that Generating Unit's Bid adder value will be reduced by the percent of the Generating Unit's capacity that is identified as meeting an LSE's Resource Adequacy Requirements. The reduced Bid Adder will be applied to that Generating Unit's entire Default Energy Bid curve.

39.9 CRR Monitoring and Affiliate Disclosure Requirements.

The CAISO will monitor the CRR holdings and CAISO Markets activity for anomalous market behavior, gaming, or exercise of market power resulting from CRR ownership concentrations that are not aligned with actual transmission usage as a result of secondary market auction outcomes. If the CAISO identifies such behavior it may seek FERC approval to impose position limits on the total number or MW quantity of

CRRs that may be held by any single entity and its affiliates. CRR Holders must notify the CAISO of all entities with which the CRR Holder is affiliated that are CRR Holders or Market Participants.

ARTICLE V – RESOURCE ADEQUACY

40 RESOURCE ADEQUACY DEMONSTRATION FOR ALL SCHEDULING COORDINATORS SCHEDULING DEMAND IN THE CAISO CONTROL AREA.

40.1 Applicability

Each Scheduling Coordinator must inform the CAISO on an annual basis, in the manner and on the schedule set forth in the Business Practices Manual, whether each Load Serving Entity (LSE) for whom the Scheduling Coordinator submits Demand Bids and settles such transactions including Demand Charges associated with the RTM elects to be either: (i) a Reserve Sharing LSE or a (ii) Modified Reserve Sharing LSE. The CAISO may confirm with the CPUC or other Local Regulatory Authority, as applicable, the accuracy of the election by the Scheduling Coordinator for the LSEs under its jurisdiction. The determination of the CPUC or Local Regulatory Authority will be deemed binding by the CAISO on the Scheduling Coordinator and the LSE.

A Scheduling Coordinator for a Load-following MSS is not required to make an election under this Section 40. Scheduling Coordinators for Load-following MSSs are subject solely to Sections 40.2.3 and 40.3.

The State Water Resources Development System commonly know as the State Water Project of the California Department of Water Resources shall be required to develop, in cooperation with the CAISO, a program that ensures the Load Serving Entity will not unduly rely on the resource procurement practices of other Load Serving Entities.

40.2 Information Requirements Regarding Resource Adequacy Programs

40.2.1. Reserve Sharing LSEs

Scheduling Coordinators for any Reserve Sharing LSE must provide the CAISO with the following information:

(a) For a CPUC Load Serving Entity, all information or data to be provided to the CAISO as required by the CPUC and pursuant to the schedule adopted by the CPUC, including, but not limited to, annual and monthly Resource Adequacy Plans.

(b) For a Non-CPUC Load Serving Entity electing Reserve Sharing LSE status:

1. The applicable Reserve Margin, which, for each month of the year, shall not be less than 15% of each month's peak hour Demand of the Non-CPUC Load Serving Entity as determined by the Demand Forecasts as developed in accordance with Section 40.2.1(b)(3);

2. A description of the criteria for determining qualifying resource types and the Qualifying Capacity from such resources and any modifications thereto as they are implemented from time to time. The Reserve Sharing LSE may elect to utilize the criteria set forth in Section 40.8;

3. An annual and monthly Demand Forecasts on the schedule set forth in the Business Practices Manual. The annual Demand Forecast shall set forth the Non-CPUC Load Serving Entity's annual non-coincident peak Demand for its Service Area, MSS area, or TAC Area in which the Non-CPUC Load Serving Entity serves Load, unless the Non-CPUC Load Serving Entity agrees to utilize coincident peak Demand determinations provided by the California Energy Commission for such Non-CPUC Load Serving Entity. The monthly Demand Forecast shall set forth the Non-CPUC Load Serving Entity's monthly non-coincident peak Demand for its Service Area, MSS area, or the TAC Area in which the Non-CPUC Load Serving Entity serves Load, unless the Non-CPUC Load Serving Entity agrees to utilize coincident peak Demand determinations provided by the California Energy Commission for such Non-CPUC Load Serving Entity. Scheduling Coordinators for Non-CPUC Load Serving Entities electing Reserve Sharing LSE status must provide data and/or supporting information, as requested by the CAISO, for the Demand Forecasts required by this Section for each Non-CPUC Load Serving Entity and a description of the criteria upon which the Demand Forecasts were developed, and any modifications thereto as they are implemented from time to time; and

4. Annual and monthly Resource Adequacy Plans, on a schedule and in the reporting formats set forth in the CAISO's Business Practice Manual, for each Non-CPUC Load Serving Entity electing Reserve Sharing LSE status served by the Scheduling Coordinator. The annual Resource Adequacy Plan should set forth the Local Capacity Area Resources, if any,

procured by the Non-CPUC Load Serving Entity as described in Section 40.3. The monthly Resource Adequacy Plan should identify the resources the Non-CPUC Load Serving Entity will rely upon to satisfy its forecasted monthly Demand and Reserve Margin, for the relevant reporting period and must utilize the Net Qualifying Capacity requirements of Section 40.4.

40.2.2 Modified Reserve Sharing LSEs

Scheduling Coordinators for any Modified Reserve Sharing LSE must provide the CAISO with the following information:

(a) A description of the criteria for determining qualifying resource types and the Qualifying Capacity from such resources and any modifications thereto as they are implemented from time to time. The Modified Reserve Sharing LSE may elect to utilize the criteria set forth in Section 40.8;

(b) Data or supporting information, as requested by the CAISO, for the Demand Forecasts required by Section 40.5.1 for each Modified Reserve Sharing LSE served by a Scheduling Coordinator and a description of the criteria upon which the Demand Forecast was developed, and any modifications thereto as they are implemented from time to time; and

(c) Annual and monthly Resource Adequacy Plans, on a schedule and in the format set forth in the CAISO's Business Practice Manual, for each Modified Reserve Sharing LSE served by the Scheduling Coordinator. The annual Resource Adequacy Plan should set forth the Local Capacity Area Resources, if any, procured by the Modified Reserve Sharing LSE as described in Section 40.3. The monthly Resource Adequacy Plan should identify the resources the Modified Reserve Sharing LSE will rely upon to satisfy its forecasted monthly Demand and Reserve Margin as set forth in Section 40.5.1, for the relevant reporting period and must utilize the Net Qualifying Capacity requirements of Section 40.4.

40.2.3 Load-Following MSS

A Scheduling Coordinator for a Load-following MSS must provide an annual Resource Adequacy Plan, on a schedule and format set forth in the CAISO's Business Practice Manual. The annual Resource

Adequacy Plan should set forth the Local Capacity Area Resources, if any, procured by the Load-following MSS as described in Section 40.3.

40.3 Local Capacity Area Resource Requirements Applicable to Scheduling Coordinators for All Load Serving Entities

40.3.1 CAISO Technical Study

The CAISO will, on an annual basis, publish a technical study that determines the minimum amount of Local Capacity Area Resources that must be available to the CAISO within each Local Capacity Area identified in the technical study. The CAISO shall collaborate with the CPUC, Local Regulatory Authorities within the CAISO Control Area, and other market participants to establish the parameters, assumptions, and other criteria to be used in the technical study that Applicable Reliability Criteria.

40.3.2 Allocation of Local Capacity Area Resource Obligations

The CAISO will allocate responsibility for Local Capacity Area Resources to Scheduling Coordinators Load Serving Entities in the following sequential manner:

i. The responsibility for the aggregate Local Capacity Area Resources required for all Local Capacity Areas within each TAC Area will be allocated to all Scheduling Coordinators for Load Serving Entities that serve Load in the TAC Area in accordance with the Load Serving Entity's proportionate coincident share, on a gross Load basis, of the previous annual peak Demand in the TAC Area under the conditions used in the technical study. This will result in a MW responsibility for the entire TAC Area that may be met by procurement of that MW quantity in any Local Capacity Area in the TAC Area.

ii. For Scheduling Coordinators for Non-CPUC Load Serving Entities, the Local Capacity Area Resource obligation will be allocated based on Section 40.3.2(i) above.

iii. For Scheduling Coordinators for CPUC Load Serving Entities, the CAISO will allocate the Local Capacity Area Resource obligation based on an allocation methodology, if any, adopted by the CPUC. However, if the allocation methodology adopted by the CPUC does not fully allocate the total sum of each CPUC Load Serving Entity's proportionate share calculated under Section 40.3.2(i), the CAISO will allocate the difference to all Scheduling Coordinators for CPUC Load Serving Entities in accordance with their proportionate share calculated under 40.3.2(i). If the CPUC does not adopt an allocation methodology, the CAISO will allocate Local Capacity Area Resources to Scheduling Coordinators for CPUC Load Serving Entities based on Section 40.3.2(i).

Once the CAISO has determined the total responsibility, the CAISO will inform each Scheduling Coordinator for LSE of its specific allocated responsibility for Local Capacity Area Resources.

40.3.3 Procurement of Local Capacity Area Resource Obligations by Load Serving Entities

Nothing in this Section 40 obligates any Scheduling Coordinator to demonstrate on behalf of a Load Serving Entity that the Load Serving Entity has procured Local Capacity Area Resources to satisfy capacity requirements for each Local Capacity Area identified in the technical study. Scheduling Coordinators for Load Serving Entities may aggregate responsibilities for procurement of Local Capacity Area Resources. If a Load Serving Entity has procured Local Capacity Area Resources that satisfy generation capacity requirements for Local Capacity Areas, the Scheduling Coordinator for such Load Serving Entity shall include this information in its annual and monthly Resource Adequacy Plan(s).

40.3.4 Procurement of Local Capacity Area Resources by the CAISO

The CAISO may procure Local Capacity Area Resources, pursuant to applicable provisions of the CAISO Tariff, including any mechanism incorporated into the CAISO Tariff specifically to permit procurement of Local Capacity Area Resources by the CAISO, to the extent (i) a Scheduling Coordinator representing one or more Load Serving Entities with Load in the TAC Area in which the Local Capacity Area is located fails to demonstrate in its annual Resource Adequacy Plan procurement of its share of the Local Capacity Area Resource obligation, as determined in Section 40.3.2, in which case, the CAISO may procure Local Capacity Area Resources in the amount of the deficiency and allocate the costs of such procurement to the Scheduling Coordinator representing the deficient Load Serving Entity and/or (ii) the Local Capacity Area Resources specified in a Scheduling Coordinator's annual Resource Adequacy Plans, regardless of whether such resources meet the minimum amount of Local Capacity Area Resources that must be secured within each Local Capacity Area identified in the technical study, fail to permit or ensure compliance with Applicable Reliability Criteria, in which case, the CAISO will procure Local Capacity Area Resources in an amount and location sufficient to permit or ensure compliance with Applicable Reliability Criteria and allocate the costs of such procurement in accordance with Sections 41 and 42 of this CAISO Tariff and/or any other mechanism that may be incorporated into this CAISO Tariff specifically to address the cost allocation of Local Capacity Area Resource procurement by the CAISO under this Section. To the extent the cost of CAISO procurement under this Section is allocated to a Scheduling Coordinator, that Scheduling Coordinator will receive credit toward its Local Capacity Area Resource obligation of its pro rata share of the procured Local Capacity Area Resource.

40.4 General Requirements on Resource Adequacy Resources

40.4.1 Designation of Eligible Resources and Determination of Qualifying Capacity

The CAISO shall use the criteria provided by the CPUC or Local Regulatory Authority to determine and verify, if necessary, the Qualifying Capacity of all Resource Adequacy Resources; however, to the extent a resource is listed by one or more Scheduling Coordinators in their Resource Adequacy Plans, which apply the criteria of more than one Local Regulatory Authority that leads to conflicting Qualifying Capacity values for that resource, the CAISO will accept the methodology that results in the highest Qualifying Capacity value. Only if a Local Regulatory Authority has not established any Qualifying Capacity criteria, or chooses to rely on the criteria in this CAISO Tariff, will the provisions of Section 40.8 apply.

40.4.2 Net Qualifying Capacity Report

The CAISO shall produce an annual report posted to the CAISO Website setting forth the Net Qualifying Capacity of all Participating Generators. All other Resource Adequacy Resources may be included in the annual report under Section 40.4.2 upon their request. Any disputes as to the CAISO's determination regarding Net Qualifying Capacity shall be subject to the CAISO ADR Procedures.

40.4.3 General Qualifications for Supplying Net Qualifying Capacity

Resource Adequacy Resources included in a Resource Adequacy Plan submitted by a Scheduling Coordinator on behalf of a Load Serving Entity serving Load in the CAISO Control Area are subject to the following:

(1) Be available for testing by the CAISO to validate Qualifying Capacity and determine Net Qualifying Capacity;

(2) Provide any information requested by the CAISO to apply the performance criteria to be adopted by the CAISO pursuant to Section 40.4.5;

(3) Submit Bids into the CAISO Markets as required by this CAISO Tariff;

(4) Be in compliance with the criteria for Qualifying Capacity established by the relevant Local Regulatory Authority and provided to the CAISO; and

(5) Be subject to sanctions for non-performance as specified in the CAISO Tariff.

40.4.4. Reductions for Testing

In accordance with the procedures specified in the Business Practice Manual, Participating Generators or other Generating Units or System Units included in a Resource Adequacy Plan submitted by a Scheduling Coordinator on behalf of a Load Serving Entity serving can have its Qualifying Capacity reduced if a CAISO testing program determines that it is not capable of supplying the full Qualifying Capacity amount.

40.4.5 Reductions for Performance Criteria

No later than 12 months after the effective date of this Section 40, the CAISO will issue a report outlining a proposal with respect to performance criteria. The Scheduling Coordinator of a Resource Adequacy Resource shall provide or make available to the CAISO, subject to the confidentiality provisions of this CAISO Tariff, all documentation requested by the CAISO to determine, develop or implement the performance criteria, including, but not limited to, NERC Generating Availability Data System data. The CAISO will begin reducing Qualifying Capacity based on performance criteria after adoption of performance criteria by the CPUC and/or Local Regulatory Authorities.

40.4.6 Reductions for Deliverability

40.4.6.1 Deliverability Within the CAISO Control Area

In order to determine Net Qualifying Capacity from Resource Adequacy Resources subject to this Section 40.4, the CAISO will determine that a Resource Adequacy Resource is available to serve the aggregate of Load by means of a deliverability study. Documentation explaining the CAISO's deliverability analysis will be posted on the CAISO Website. The deliverability study shall focus on peak Demand conditions. The CAISO will update the deliverability baseline study on an annual basis, or more frequently in accordance with Good Utility Practice. To the extent the deliverability study shows that the Qualifying Capacity is not deliverable to the aggregate of Demand under the conditions studied, the Qualifying Capacity of the Resource Adequacy Resource will be reduced on a MW basis for the capacity that is undeliverable. The CAISO will utilize its interconnection process and procedures under Section 25 of the CAISO Tariff to prevent degradation of the deliverability of an existing Generating Unit that could result from the interconnection of additional Generation.

40.4.6.2 Deliverability of Imports

The CAISO shall, by means of an annual deliverability study, establish the total import capacity for each import path to be allocated to Scheduling Coordinators for Load Serving Entities. The study results shall be posted on the CAISO Website. For the purpose of accounting for import Resource Adequacy Capacity, the import capability of the system will be allocated by branch group to Scheduling Coordinators for Non-CPUC Load Serving Entities individually and to the Scheduling Coordinators for CPUC Load Serving Entities as an aggregated allocation, which will be subject to the allocation rules of the CPUC. The allocation to Scheduling Coordinators for CPUC Load Serving Entities will be the total import value by branch group minus import capacity associated with (i) Existing Transmission Contracts, (ii) Encumbrances and Transmission Ownership Rights, and (iii) resource commitments outside the CAISO Control Area of Non-CPUC Load Serving Entities, as of October 27, 2005. The allocation to Scheduling Coordinators for Non-CPUC Load Serving Entities will be the resource commitments outside the CAISO Control Area of Scheduling Coordinators for Non-CPUC Load Serving Entities, as of October 27, 2005. Import capacity associated with (i) Existing Transmission Contracts and (ii) Encumbrances and

Transmission Ownership Rights shall be reserved for holders of such commitments as part of the deliverability study and will not be subject to allocation under these rules. Resource commitments outside the CAISO Control Area of any Load Serving Entity entered into after October 27, 2005 will be given identical allocation priority. This allocation does not guarantee or result in any actual transmission service being allocated and is only used for determining the maximum Resource Adequacy Capacity that can be credited towards satisfying a Scheduling Coordinator's obligations under its Resource Adequacy Plan. Upon the request of the CAISO, Scheduling Coordinators must provide the CAISO with information on existing Energy or capacity import contracts and any trades or sales of their Load share allocation. Such information will be subject to the confidentiality provisions of this CAISO Tariff. The CAISO will inform the CPUC if a Resource Adequacy Plan submitted by a Scheduling Coordinator for a CPUC Load Serving Entity exceeds its allocation of import capacity. The CAISO will inform the Scheduling Coordinator for a Non-CPUC Load Serving Entity if its Resource Adequacy Plan exceeds the Non-CPUC Load Serving Entity's allocation of import capacity and will either: (i) reduce all Resource Adequacy Capacity from imports of that Scheduling Coordinator on a pro rata basis or (ii) reduce a specific Resource Adequacy Capacity from imports as instructed by the Scheduling Coordinator so as to equal the allocated amount of import capacity.

40.4.7 Submission of Supply Plans

Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity shall provide the CAISO with an annual and/or monthly plan, as applicable, on the schedule set forth in the Business Practices Manual verifying their agreement to provide the Resource Adequacy Capacity listed on the annual and/or monthly Resource Adequacy Plan, as applicable, submitted by a Scheduling Coordinator for a Load Serving Entity. The Supply Plan must be in the form of the template provided on the CAISO Website.

40.5 Requirements Applicable to Modified Reserve Sharing LSEs Only

40.5.1 Forecast Requirements

Scheduling Coordinators on behalf of Modified Reserve Sharing LSEs for whom they submit Demand Bids must:

(1) Submit, as part of its monthly Resource Adequacy Plan, a Demand Forecast reflecting the non-coincident peak hour Demand to be served by each Modified Reserve Sharing LSE for the relevant month, measured in megawatts. This Demand Forecast plus the applicable Reserve Margin of 15% of the Demand Forecast shall establish the Scheduling Coordinator's monthly Resource Adequacy Plan demonstration for each Modified Reserve Sharing LSE for the relevant month.

(2) Submit, on the schedule and in the manner set forth in the Business Practices Manual, hourly Demand Forecasts for each Trading Hour of the next Trading Day for each Modified Reserve Sharing LSE represented.

40.5.2 Day Ahead Scheduling and Bidding Requirements

Scheduling Coordinators on behalf of Modified Reserve Sharing LSEs serving Load within the CAISO Control Area for whom they submit Demand Bids:

(1) Submit into the IFM, a Self-Schedule or Bid equal to 115% of the hourly Demand Forecasts for each Modified Reserve Sharing LSE it represents for each Trading Hour for the next Trading Day. Subject to Section 40.5.6, the resources included in a Self-Scheduled and/or bid in each Trading Hour to satisfy 115% of the Modified Reserve Sharing LSE's hourly Demand Forecasts will be deemed Resource Adequacy Resources and (i) shall be those resources listed in the Modified Reserve Sharing LSE's monthly Resource Adequacy Plan and (ii) shall include all Local Capacity Area Resources listed in the Modified Reserve Sharing LSE's annual Resource Adequacy Plan, if any, except to the extent the Local Capacity Area Resources, if any, are unavailable due to any outages or reductions in capacity reported to the CAISO in accordance with this CAISO Tariff.

i. A Local Capacity Area Resource that has not fully submitted a Bid or Self-Schedule for all of its Resource Adequacy capacity of will be subject to the CAISO's optimization for the remainder of its capacity, which must be Bid into the Day-Ahead Market; however, to the extent the Generating Unit providing Local Capacity Area Resource capacity constitutes a Use-Limited Resource under Section 40.6.4, the provisions of Section 40.6.4 will apply.

ii. If the Resource Adequacy Resource submits a Bid for Ancillary Services, the Energy Bid associated with the Bid for Ancillary Services will be optimized by the CAISO. However, pursuant to Section 8.6.2, to the extent the Local Capacity Area Resource Self-Provides Ancillary Services and local constraints result is a solution in the MPM-RRD that involves Load reduction, then Self-Provided AS from the Local Capacity Area Resource will be converted into Ancillary Service Bids at the Minimum Bid Price for Ancillary Services as prescribed in Section 39.6.1.5.

iii. Resource Adequacy Resources must participate in the RUC to the extent that the resource has not submitted a Self-Schedule or already committed to provide Energy or capacity in the IFM. Resource Adequacy Resources will be required to offer into RUC and will be considered based on a $0 RUC Availability Bid.

iv. Capacity from Resource Adequacy Resources selected in RUC will not be eligible to receive a RUC Availability Payment.

(2) Resource Adequacy Resources of Modified Reserve Sharing LSEs that do not clear in the IFM or are not committed in RUC shall have no further offer requirements in HASP or Real-Time, except under System Emergencies as provided in this CAISO Tariff.

(3) Resource Adequacy Resources committed by the CAISO must maintain that commitment through Real-Time. In the event of a forced outage on a Resource Adequacy Resource committed in the Day-Ahead Market to provide Energy, the Scheduling Coordinator for the Modified Reserve Sharing LSE will have up to the next HASP bidding opportunity, plus one hour, to replace the lesser of:(i) the committed resource suffering the forced outage, (ii) the quantity of Energy committed in the Day-Ahead Market, or (iii) 107% of the hourly forecast load.

40.5.3 Demand Forecast Accuracy

On a monthly basis, the CAISO will review meter data to evaluate the accuracy or quality of the hourly Day-Ahead Demand Forecasts submitted by the Scheduling Coordinator on behalf of Modified Reserve Sharing LSEs. If the CAISO determines, based on its review, that one or more Demand Forecasts materially under-forecasts the Load of the Modified Reserve Sharing LSEs for whom the Scheduling Coordinator schedules, after accounting for weather adjustments, the CAISO will notify the Scheduling Coordinator of the deficiency and will cooperate with the Scheduling Coordinator and Modified Reserve Sharing LSE(s) to revise its Demand Forecast protocols or criteria. If the material deficiency persists for three (3) consecutive months with respect to the monthly Demand Forecast or ten (10) hourly occurrences over a minimum of two (2) non-consecutive week days within a month, the CAISO may: (i) inform State authorities including, but not necessarily limited to the Legislature, and identify the Modified Reserve Sharing LSE(s) represented by the Scheduling Coordinator and (ii) assign to the Scheduling Coordinator responsibility for all Tier 1 RUC charges as specified in Section 11.8.6.5 to address the uncertainty caused by the Scheduling Coordinator's deficient hourly Demand Forecasts until the deficiency is addressed.

40.5.4 Requirement to Make Resources Available During System Emergencies

Scheduling Coordinators for Modified Reserve Sharing LSEs that are MSS Operators shall make resources available to the CAISO during a System Emergency in accordance with the provisions of Section 4.9 and their Metered Subsystem Agreement. Scheduling Coordinators for all other Modified Reserve Sharing LSEs shall make available to the CAISO upon a warning or emergency notice of an actual or imminent System Emergency all resources that have not submitted a Self-Schedule or Economic Bid in the IFM that were listed in the Modified Reserve Sharing LSEs monthly Resource Adequacy Plan that are physically capable of operating without violation of any applicable law.

40.5.5 Consequence of Failure to Meet Scheduling Obligation

(1) If the Scheduling Coordinator for the Modified Reserve Sharing LSE fails to submit a Self-Schedule or submit Bids equal to 115% of its hourly Demand Forecasts for each Trading Hour for the next Trading Day in the IFM and RUC, the Scheduling Coordinator will be charged a capacity surcharge of three times the price of the relevant Day-Ahead Hourly LAP LMP in the amount of the shortfall. To the extent the Scheduling Coordinator for the Modified Reserve Sharing LSE schedules imports on one or more Scheduling Points in an aggregate megawatt amount greater than its aggregate import deliverability allocation under Section 40.4.6.2, the quantity of megawatts in excess of its import deliverability allocation

will not count toward satisfying the Modified Reserve Sharing LSE's scheduling obligation, unless it clears the Day-Ahead Market.

(2) If the Scheduling Coordinator for the Modified Reserve Sharing LSE cannot fulfill its obligations under Section 40.5.2(3) of this CAISO Tariff, the Scheduling Coordinator for the Modified Reserve Sharing LSE will be charged a capacity surcharge of two times the average of the six (6) Settlement Interval LAP prices for the hour in the amount of the shortfall. Energy scheduled in the HASP will not net against, or be used as a credit to correct, any failure to fulfill the Day-Ahead IFM hourly scheduling and RUC obligation in Section 40.5.3.

(3) Any Energy surcharge received by the CAISO pursuant to Section 40.5.5, shall be allocated to Scheduling Coordinators representing other Load Serving Entities in proportion to metered Demand during the relevant Trading Hour(s).

40.5.6 Substitution of Resources

Subject to the provisions of this Section 40.5, the Scheduling Coordinator for a Modified Reserve Sharing LSE may substitute for its Resource Adequacy Resources listed in its monthly Resource Adequacy Plan provided:

(1) Substitutions must occur no later than the close of the IFM; and

(2) Resources eligible for substitution are either imports or capacity from Non-Resource Adequacy Resources or Resource Adequacy Resources with additional available capacity defined as Net Qualifying Capacity in excess of previously sold Resource Adequacy Capacity; however the Local Capacity Area Resource may be substituted only with capacity from Non-Resource Adequacy Resources located in the same Local Capacity Area.

40.6 Requirements Applicable to Scheduling Coordinators for Reserve Sharing LSEs and Resources Providing Resource Adequacy Capacity to Reserve Sharing LSEs

This Section 40.6 does not apply to Resource Adequacy Resources of Load-following MSSs and those entities that participate in the Modified Reserve Sharing program in Section 40.5. 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 report-month in accordance with this Section 40.6.

40.6.1 Day-Ahead Availability

Scheduling Coordinators supplying Resource Adequacy Capacity shall make the Resource Adequacy Capacity, except for that subject to Section 40.6.4, available Day-Ahead to the CAISO as follows:

(1) Resource Adequacy Resources physically capable of operating must Self-Schedule or submit Economic Bids or Self-Schedules for their Resource Adequacy Capacity into the IFM and RUC.

(2) Any inter-temporal constraints such as Minimum Run times must not be more restrictive than those pre-specified in the Master File limitations or as otherwise required by this CAISO Tariff or by Good Utility Practice.

(3) Resource Adequacy Resources that do not submit Self-Schedules or Economic Bids reflecting all of their Resource Adequacy Capacity will be subject to the CAISO's optimization for the remainder of their Resource Adequacy Capacity Bids into the Day-Ahead Market. If the Resource Adequacy Resource submits a Bid for Ancillary Service(s), the Energy Bid associated with the Bid for Ancillary Services will be optimized by the CAISO.

(4) Resource Adequacy Resources must participate in the RUC to the extent that the resource has available Resource Adequacy Capacity that is not reflected in a Self-Scheduled is already committed to provide Energy or capacity in the IFM. Resource Adequacy Resources will be subject to RUC and will be optimized at a zero dollar RUC Availability Bid.

(5) Capacity from Resource Adequacy Resources selected in RUC will not be eligible to receive a RUC Availability Payment.

40.6.2 Real-Time Availability.

Resource Adequacy Resources that have been committed by the CAISO in the Day-Ahead Market or the RUC for part of their Resource Adequacy Capacity or have submitted a Self-Schedule for part of their Resource Adequacy Capacity must remain available to the CAISO through Real-Time, including capacity reflected in the Day-Ahead Schedule and any remaining capacity, for the scheduled and non-scheduled portions of their Resource Adequacy Capacity, subject to the provisions of Section 40.6.4.

40.6.3 Additional Availability Requirements For Short-Start Units.

Short Start Units must meet the following Real-Time availability requirements:

(1) Submit a Bid for the resource in the HASP; or

(2) Submit a Bid for the resource into the Real-Time Market.

The CAISO may waive these availability obligations for Short-Start Units not have not submitted a Bid or Self-Schedule or selected in the IFM or RUC based on the procedure published on the CAISO Website.

40.6.4 Additional Availability Requirements for Use-Limited Resources

40.6.4.1 Registration of Use-Limited Resources

Scheduling Coordinators for Use-Limited Resources, other than for hydro Generating Units, must provide the CAISO an application in the form specified on the CAISO Website requesting registration of a specifically identified resource as a Use-Limited Resource. This application shall include specific operating data and supporting documentation including, but not limited to;

(1) a detailed explanation of why the unit is subject to operating limitations;

(2) historical data to show attainable MWhs for each 24-hour period during the preceding year. This data should include, as applicable, environmental restrictions for NOx, SOx, or other factors.

(3) further data or other information as may be requested by the CAISO to understand the operating characteristics of the unit.

Within, 5 days upon receipt of the application, the CAISO will respond to the Scheduling Coordinator as to whether or not the CAISO agrees that the facility is eligible to be a Use-Limited Resource. If the CAISO determines the facility is not a Use-Limited Resource, the Scheduling Coordinator may challenge that determination in accordance with the CAISO ADR Procedures.

40.6.4.2 Use Plan

With regard to Use-Limited Resources, the Scheduling Coordinator will provide by September for the following year, a proposed annual use plan for each Use-Limited Resource that is a Resource Adequacy Resource. The proposed annual use plan will delineate on a month-by-month basis the total MWhs of generation, total run hours, expected daily supply capability (if greater than four hours) and the daily energy limit, operating constraints, and the timeframe for each constraint. The CAISO will have an opportunity to discuss the proposed annual use plan with the Scheduling Coordinator and suggest potential revisions to meet reliability needs of the system. The Scheduling Coordinator shall then submit its final annual plan by October of each year. The Scheduling Coordinator will be able to update the projections made in the annual use plan in the monthly Resource Adequacy Plans. The annual use plan must reflect the potential operation of the Use-Limited Resource at a level no less than the minimum criteria set forth by the Local Regulatory Authority for qualification of the resource.

40.6.4.3 Bidding Requirements on Use-Limited Resources

40.6.4.3.1 Non-Hydro and Dispatchable Use Limited Resources

Use-Limited Resources, other than those subject to the provisions of 40.6.4.3.2, must submit a Supply Bid or Self-Schedule for their Resource Adequacy Capacity in the Day-Ahead Market whenever the Use-Limited Resources are physically capable of operating in accordance with their operating criteria, including environmental or other regulatory requirements. Use-Limited Resources will also provide a daily energy limit as part of its Day-Ahead Market offer to enable the CAISO to schedule them for the period in which they are capable of providing the Energy. To the extent that the daily Energy limit has been Self-Scheduled, no further action is necessary by the CAISO, unless rescheduling of the Energy is necessary for system reliability. Use-Limited Resources will attempt to reschedule the Energy in recognition of the system reliability concern, to the extent that the change is possible without violating a Use-Limited Resource's operating criteria.

40.6.4.3.2 Hydro and Non-Dispatchable Use Limited Resources

Hydro resources and Non-Dispatchable Use-Limited Resources shall submit Self-Schedule 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 HASP. Such Resources shall also revise their Self-Schedules or submit additional Bids in HASP based on the most current information available regarding expected Energy deliveries. Hydro resources and Non-Dispatchable Use-Limited Resources will not be subject to commitment in the RUC process. The CAISO will retain discretion as to whether a particular resource should be considered a Non-Dispatchable Use-Limited Resource, and this decision will be made in accordance with the provisions of Section 40.6.4.1.

40.6.4.3.3 Availability of Use Limited Resources During System Emergencies

All Use-Limited Resources remain subject to Section 7.7.2.3 regarding System Emergencies to the extent the Use-Limited Resource is owned or controlled by a Participating Generator.

40.6.5 Additional Availability Requirements for System Resources

In the IFM, the multi-hour block constraints of the System Resource are honored in the optimization. The CAISO anticipates that multi-hour block System Resources that are Resource Adequacy Resources must be capable of hourly selection by the CAISO if not fully committed in the IFM. If selected in the RUC, the System Resource must be dispatchable in those hours in the HASP and Real Time Market. For existing System Resources with a call-option that expires prior to the completion of the IFM, such System Resources listed on a Resource Adequacy Plan must be reported to the CAISO for consideration in any CAISO multi-day RUC/unit commitment process.

40.6.6 Availability Requirements for Partial Resource Adequacy Resources

A Partial Resource Adequacy Resource has capacity that is not committed to meet a Resource Adequacy obligation in the CAISO Control Area. Only that output of the resource that is designated by a Scheduling Coordinator as Resource Adequacy Capacity in its monthly or annual Resource Adequacy Plan shall have an availability obligation to the CAISO.

40.6.7 Availability Requirements for Long Start Units

40.6.7.1 Release of 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 submit a Self-Schedule a Wheel-Out in the HASP, unless precluded by terms of its contract or other restrictions.

40.6.7.2 Obligation of Long-Start Units to Offer Remaining Capacity in Real-Time

Long Start Units that have been committed by the CAISO in the Day-Ahead Market or the RUC for part of their Resource Adequacy Capacity or have submitted a Self-Schedule for part of their Resource

Adequacy Capacity must remain available to the CAISO through Real-Time for the full value of their Resource Adequacy Capacity.

40.6.8 Use of Default Energy Bids

Prior to completion of the Day-Ahead Market, the CAISO will determine if dispatchable Resource Adequacy Capacity from Resource Adequacy Resources has not been reflected in a Bid and will insert a Default Energy Bid for any dispatchable Resource Adequacy Capacity that is not reflected in a Bid into the CAISO Day-Ahead Market and for which the CAISO has not received notification of an Outage. 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 HASP process and will insert a Default Energy Bid for any remaining dispatchable Resource Adequacy Capacity for which the CAISO has not received notification of an Outage.

40.6.9 Availability Requirements for Grandfathered Firm Liquidated Damages Contracts

Resource Adequacy Capacity represented by a Firm Liquidated Damages Contract and relied upon by a Scheduling Coordinator in a monthly or annual Resource Adequacy shall be Self-Scheduled or Bid in the Day-Ahead IFM to the extent such scheduling right exists under the Firm Liquidated Damages Contract. For purposes of this Section, Firm Liquidated Damages Contracts are those transactions utilizing or consistent with Service Schedule C of the Western Systems Power Pool Agreement or the Firm Liquidated Damages product of the Edison Electric Institute pro forma agreement, or any other similar firm energy contract that does not require the seller to source the energy from a particular unit, and specifies a delivery point internal to the CAISO Control Area.

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 a Resource Adequacy Resource to prevent or alleviate a System Emergency.

40.6.12 Participating Loads

Participating Loads included in a Resource Adequacy Plan and Supply Plan, if the Scheduling Coordinator for the Participating Loads is not the same as that for the Load Serving Entity, will be dispatched by the CAISO in accordance with the terms and conditions established by the CPUC or the Local Regulatory Authority.

40.7 Compliance

If the CAISO's review of an annual or monthly Resource Adequacy Plan reveals resource deficiencies, the CAISO will report the deficiencies to the CPUC or Local Regulatory Authority and Scheduling Coordinator submitting Bids for the Load Serving Entity and will coordinate with the CPUC or Local Regulatory Authority to request that the Scheduling Coordinator scheduling Demand revise the plan, as appropriate.

40.7.1 Other Compliance Issues

Scheduling Coordinators representing Generating Units, System Units or System Resources supplying Resource Adequacy Capacity that fail to provide the CAISO with an annual and/or monthly plan, as applicable, as set forth in Section 40.7, shall be subject to Section 37.6.1.

40.7.2 Penalties for Non-Compliance

The failure of a Resource Adequacy Resource or Resource Adequacy Capacity to make itself available to the CAISO in accordance with the requirements of Sections 40 and/or to operate the Resource Adequacy Resource by placing it online and/or in a manner consistent with a submitted Bid or Default Energy Bid shall be subject to the sanctions set forth in Section 37.2.

40.8 CAISO Default Qualifying Capacity Criteria

40.8.1 Applicability

The criteria in this Section 40.8 shall apply only: (i) where the CPUC or Local Regulatory Authority has not established and provided to the CAISO criteria to determine the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity for such eligible resource types and (ii) until the CAISO has been notified in writing by the CPUC of its intent to overturn, reject or fundamentally modify the capacity-based framework in CPUC Decisions 04-01-050 (Jan. 10, 2004), 04-10-035 (Oct. 28, 2004), and 05-10-042 (Oct. 31, 2005).

40.8.1.2 Nuclear and Thermal

Nuclear and thermal units, other than Qualifying Facilities with effective contracts under the Public Utility Regulatory Policies Act addressed in Section 40.8.1.8 below, must be a Participating Generator or a System Unit. The Qualifying Capacity of nuclear and thermal units, other than Qualifying Facilities addressed in Section 40.8.1.8, will be based on net dependable capacity defined by North American Electric Reliability Council ("NERC") Generating Availability Data System ("GADS") information.

40.8.1.3 Hydro

Hydro units, other than Qualifying Facilities with contracts under the Public Utility Regulatory Policies Act, must be either Participating Generators or System Units. The Qualifying Capacity of a pond or pumped storage hydro unit, other than a QF, will be determined based on net dependable capacity defined by NERC GADS minus variable head derate based on an average dry year reservoir level. The Qualifying Capacity of a pond or pumped storage hydro unit that is a QF will be determined based on historic performance during the Standard Offer 1 peak hours of noon to 6:00 p.m., using a three-year rolling average.

The Qualifying Capacity of all run-of-river hydro units, including Qualifying Facilities, will be based on net dependable capacity defined by NERC GADS minus an average dry year conveyance flow, stream flow, or canal head derate. As used in this section, average dry year reflects a one-in-five year dry hydro scenario (for example, using the 4th driest year from the last 20 years on record).

40.8.1.4 Unit-Specific Contracts

Unit-specific contracts with Participating Generators or System Units will qualify as Resource Adequacy Capacity subject to the verification that the total MW quantity of all contracts from a specific unit do not exceed the total Net Qualifying Capacity (MW) consistent with the Net Qualifying Capacity determination for that unit.

40.8.1.5 Contracts with Liquidated Damage Provisions

Firm energy contracts with liquidated damages provisions, as generally reflected in Service Schedule C of the Western Systems Power Pool Agreement or the Firm LD product of the Edison Electric Institute pro forma agreement, or any other similar firm energy contract that does not require the seller to source the energy from a particular unit, and specifies a delivery point internal to the CAISO Control Area entered into before October 27, 2005 shall be eligible to count as Qualifying Capacity until the end of 2008. A Scheduling Coordinator, however, cannot have more than 75% of its portfolio of Qualifying Capacity met by contracts with liquidated damage provisions for 2006. This percentage will be reduced to 50% for 2007 and 25% for 2008.

40.8.1.6 Wind and Solar

As used in this Section, wind units are those wind Generating Units without backup sources of generation and solar units are those solar Generating Units without backup sources of generation. Wind and Solar units, other than Qualifying Facilities with effective contracts under the Public Utility Regulatory Policies Act, must be participants in the CAISO's Participating Intermittent Resource Program ("PIRP") or subject to availability provisions of Section 40.6 of this CAISO Tariff.

The Qualifying Capacity of all wind or solar units, including Qualifying Facilities, will be based on their monthly historic performance during the Standard Offer 1 peak hours of noon to 6:00 p.m., using a three-year rolling average.

40.8.1.7 Geothermal

Geothermal units, other than Qualifying Facilities addressed in Section 40.8.1.8, must be Participating Generators or System Units. The Qualifying Capacity of geothermal units, other than Qualifying Facilities addressed in Section 40.8.1.8, will be based on NERC GAD net dependable capacity minus a derate for steam field degradation.

40.8.1.8 Treatment of Qualifying Capacity for Qualifying Facilities

Qualifying Facilities must be Participating Generators (signed a Participating Generator or QF Participating Generator Agreement) or System Units, unless they have a PURPA contract. Except for hydro, wind, and solar Qualifying Facilities addressed pursuant to Sections 40.8.1.3 and 40.8.1.6 above, the Qualifying Capacity of Qualifying Facilities under PURPA contracts, will be based on historic monthly generation output during Standard Offer 1 peak hours of noon to 6:00 p.m. (net behind the meter loads) during a three-year rolling average.

40.8.1.9 Participating Loads

The Qualifying Capacity of Participating Loads shall be the average reduction in demand for over a three-year period on a per dispatch basis or, if the Participating Load does not have three years of performance history, based on comparable evaluation data using similar programs. Participating Loads must be available at least 48 hours and if the Participating Loads can only be dispatched for a maximum of two hours per event, than only .89 of a Scheduling Coordinator's portfolio may be made up of such Participating Loads.

40.8.1.10 Jointly-Owned Facilities

A jointly-owned facility must be either a Participating Generator or a System Unit. The Qualifying Capacity for the entire facility will be determined based on the type of resource as described elsewhere in this Section. In addition, the Scheduling Coordinator must provide the CAISO with a demonstration of its entitlement to the output of the jointly-owned facility's Qualified Capacity and an explanation of how that entitlement may change if the facility's output is restricted.

40.8.1.11 Facilities under construction

The Qualifying Capacity for facilities under construction will be determined based on the type of resource as described elsewhere in this Section. In addition, the facility must have been in commercial operation for no less than one month to be eligible to be included as a Resource Adequacy Resource in a Scheduling Coordinator's monthly plan.

40.8.1.12 System Resources

40.8.1.12.1 Dynamic System Resources

Dynamic System Resources shall be treated similar to resources within the CAISO Control Area, except with respect to the deliverability screen under Section 40.4.6.1. However, eligibility as a Resource

Adequacy resource is contingent upon a showing by the Scheduling Coordinator that the Dynamic System Resource has secured transmission through any intervening Control Areas for the operating hours that cannot be curtailed for economic reasons or bumped by higher priority transmission and that the Load Serving Entity upon which the Scheduling Coordinator is submitting Demand Bids has an allocation of import capacity at the import Scheduling Point under Section 40.4.6.2 of the CAISO Tariff that is not less than the Resource Adequacy Capacity provided by the Dynamically Scheduled System Resource.

40.8.1.12.2 Non-Dynamic System Resources.

For Non-Dynamic System Resources, the Scheduling Coordinator must demonstrate that the Load Serving Entity upon which the Scheduling Coordinator is scheduling Demand has an allocation of import allocation at the import Scheduling Point under Section 40.4.6.2 of the CAISO Tariff that is not less than the Resource Adequacy Capacity from the Non-Dynamic System Resource. The Scheduling Coordinator must also demonstrate that the Non-Dynamic System Resource is covered by Operating Reserves, unless, unit contingent, in the sending Control Area and cannot be curtailed for economic reasons. Eligibility as Resource Adequacy Capacity would be contingent upon a showing of securing in any intervening Control Areas transmission for the operating hours making use of highest priority transmission offered by the intervening Transmission Operator that cannot be curtailed for economic reasons. With respect to Non-Dynamic System Resources, any inter-temporal constraints such as multi-hour run blocks, must be explicitly identified in the monthly Resource Adequacy plan, and no constraints may be imposed beyond those explicitly stated in the plan.

~~ARTICLE V – RESOURCE ADEQUACY~~

~~40 RESOURCE ADEQUACY.~~

~~40.1 Must-Offer Obligations.~~

~~40.1.1 Applicability.~~

~~The requirements of Section 40.1 shall apply to (a) all Participating Generators, and (b) all persons, regardless of whether the person is a "public utility" as defined in Section 201 of the Federal Power Act, that own or control one or more non-hydroelectric Generating Units, System Units or System Resources located in California from which energy or capacity is either: (i) sold through any market operated by the ISO, or (ii) transmitted over the ISO Controlled Grid. Each person described in this Section 40.1.1 is referred to in the ISO Tariff as a "Must-Offer Generator." The requirements of this Section 40.1 shall apply to all non-hydroelectric Generating Units located in California that are owned or controlled by a Must-Offer Generator.~~

~~40.1.2 Available Generation.~~

~~For the purposes of this Section 40.1, a Must-Offer Generator's "Available Generation" from a non-hydroelectric Generating Unit shall be: (a) the Generating Unit's maximum operating level adjusted for any outages or reductions in capacity reported to the ISO in accordance with Section 7 or 40.1.3 and for any limitations on the Generating Unit's operation under applicable law, including contractual obligations, which shall be reported to the ISO, (b) minus the Generating Unit's scheduled operating point as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the Generating Unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the Must-Offer Generator's Native Load.~~

~~40.1.3 Reporting Requirements for Non-Participating Generators.~~

~~So that the ISO may determine the Available Generation of all Must-Offer Generators, Must-Offer Generators that are not Participating Generators shall be required to file with the ISO, for each non-hydroelectric Generating Unit located in California they own or control: (i) the Unit's minimum operating level; (ii) the Unit's maximum operating level; and (iii) the Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch Must-Offer Generators. In addition, Must-Offer Generators that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 40.1, notify the ISO, as soon as practicable, of any Planned Maintenance Outages,~~

~~Forced Outages, Force Majeure Event outages or any other reductions in their maximum operating levels.~~

~~40.1.4 Obligation To Offer Available Capacity.~~

~~Except as set forth in Section 40.1.6, all Must-Offer Generators shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 40.1.2.~~

~~40.1.5 Submission of Bids and Applicability of the Proxy Price.~~

~~For each Operating Hour, Must-Offer Generators shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 34.2. In addition, the ISO shall calculate for each gas-fired Must-Offer Generator, in accordance with Section 34.9, a Proxy Price for Energy.~~

~~If a Must-Offer Generator fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the unbid quantity of the Must-Offer Generator's Available Generation will be deemed by the ISO to be bid at the Must-Offer Generator's Proxy Price for that hour if: (i) the applicable Generating Unit is a gas-fired unit and (ii) the Must-Offer Generator has provided the ISO with adequate data in compliance with Sections 40.1.7 and 40.1.3 for the applicable Generating Unit. For all other Generating Units owned or controlled by a Must-Offer Generator, the unbid quantity of the Must-Offer Generator's Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order, the ISO will insert this unbid quantity into the Must-Offer Generator's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the Must-Offer Generator's Available Generation.~~

~~40.1.6 Must-Offer Obligation Process.~~

~~Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 40.1.4 of this ISO Tariff, for one or more of their Generating Units.~~

~~All Must-Offer Generators obligated under the must-offer obligation that have not submitted Day-Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all available capacity. If conditions permit, and at the ISO's non-discriminatory and sole~~

~~discretion, the ISO may grant waivers and allow a Must-Offer Generator to remove one or more Generating Units from service.~~

~~The hours for which waivers are not granted shall constitute Waiver Denial Periods. A Waiver Denial Period shall be extended as necessary to accommodate Generating Unit minimum up and down times. Units shall be on-line in real time during Waiver Denial Periods, or they will be in violation of the must-offer obligation. Exceptions shall be allowed for verified forced outages. The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). The ISO shall inform a Must-Offer Generator that its Waiver request has been approved, disapproved or revoked, and shall provide the Must-Offer Generator with the reason(s) for the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify Must-Offer Generators of the ISO decisions on pending Waiver requests received no later than 10:00 a.m. (beginning of Hour Ending 11) no later than 11:30 a.m. (middle of Hour Ending 12) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m. on the following day, notify Must-Offer Generators of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m. (beginning of Hour Ending 11) on the day before; (3) end Waiver Denial Periods at any time; and (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to the time a unit would be required to be on-line generating at its Pmin.~~

~~40.1.6.1 Recovery of Minimum Load Costs By Must-Offer Generators.~~

~~40.1.6.1.1 Eligibility.~~

~~Except as set forth below, Generating Units shall be eligible to recover Minimum Load Costs during Waiver Denial Periods. Units from Must-Offer Generators that incur Minimum Load Costs during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Must-Offer Generator has a Final Hour-Ahead Energy Schedule, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a Must-Offer Generator generating at minimum load in compliance with the must-offer obligation, produces a quantity of Energy that varies from its minimum operating level by more than the Tolerance Band, the Must-Offer Generator shall not be eligible to~~

~~recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a Must-Offer Generator's resource produces a quantity of Energy above minimum load due to an ISO Dispatch Instruction, the Must-Offer Generator shall recover its Minimum Load Costs and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible Must-Offer Generator for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from Must-Offer Generators that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) To the extent the Instructed Imbalance Energy payments are not sufficient to cover the generator's Minimum Load Cost as defined in Section 40.1.6.1.2 of this Tariff, the generator will also receive an uplift payment for its Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.~~

~~40.1.6.1.1.1 Payments for Imbalance Energy Above the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.~~

~~When, on a Settlement Interval basis, a Must-Offer Generator's Generating Unit produces a quantity of Energy above the Generating Unit's minimum operating level due to an ISO Dispatch Instruction, the Must-Offer Generator shall recover its Minimum Load Costs and its bid costs, based on the ISO's instruction, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band.~~

~~40.1.6.1.1.2 Payments for Imbalance Energy for the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.~~

~~A Generating Unit operating at or near its operating level during a Waiver Denial Period either (1) without a forward Schedule for its minimum operating level Energy or (2) with a Schedule to a special-purpose Demand ID for the sole purpose of Scheduling the minimum operating level Energy shall be paid, in addition to being paid its Minimum Load Costs subject to eligibility as set forth in Section 40.1.6.1.1, an amount equal to the Resource Specific Settlement Interval Ex Post Price times the amount of Energy actually delivered.~~

~~40.1.6.1.2 Minimum Load Costs.~~

~~The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: 1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.1.7) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas; and 2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.~~

~~40.1.6.1.3 Invoicing Minimum Load Costs.~~

~~The ISO shall determine each Scheduling Coordinator's Minimum Load Costs and make payments for these costs as part of the ISO's market settlement process. Scheduling Coordinators may submit to the ISO data detailing the hours for which they are eligible to recover Minimum Load Costs. Scheduling Coordinators who elect to submit data on hours they are eligible to recover Minimum Load Costs must: 1) use the Minimum Load Cost invoice template posted on the ISO Home Page, and 2) submit the invoice on or before fifteen (15) Business Days following the last Trading Day in the month in which such costs were incurred, except that Scheduling Coordinators seeking reimbursement for Minimum Load Costs incurred between May 29, 2001, and June 30, 2002 must submit their data to the ISO by August 5, 2002.~~

~~40.1.6.1.4 Allocation of Minimum Load Costs.~~

~~For each Settlement Interval, the ISO shall determine that the Minimum Load Costs for each unit operating during a Waiver Denial Period are due to (1) local reliability requirements, (2) zonal requirements, or (3) Control Area-wide requirements. For each such month, the ISO shall sum the Settlement Interval Minimum Load Costs and shall allocate those costs as follows:~~

~~(1) if the Generating Unit was operating to meet local reliability requirements, the incremental locational cost shall be allocated to the Participating TO in whose PTO Service Territory the Generating Unit is located, or, where the Generating Unit is located outside the PTO Service Territory of any Participating TO, to the Participating TO or Participating TOs whose PTO Service Territory or Territories are contiguous to the Service Area in which the Generating Unit is located, in proportion to the benefits that each such Participating TO receives, as determined by the ISO. Where the costs allocated under this section are allocated to two or more Participating TOs, the ISO shall file the allocation under Section 205 of the Federal Power Act. For the purposes of this section, the incremental locational cost shall be the additional costs associated with committing and operating a particular unit or units to meet a local reliability requirement over the costs of a less expensive unit or units that would have been committed and operated absent the local reliability requirement. If a unit is committed in real-time for local reliability, its Minimum Load costs shall be considered incremental locational costs. Costs allocated under this part (1) shall be considered Reliability Services Costs.~~

~~(2) if the Generating Unit was operating due to Inter-Zonal Congestion, the Minimum Load Costs shall be allocated on a monthly basis to each Scheduling Coordinator in the constrained Zone based on the ratio of that Scheduling Coordinator's monthly Demand to the sum of all Scheduling Coordinator's monthly Demand in that Zone;~~

~~(3) if the Generating Unit was operating to satisfy an ISO Control Area-wide need, the ISO shall allocate the Minimum Load Costs in the following way:~~

~~a. first, to the monthly absolute total of all Net Negative Uninstructed Deviation (determined for each Settlement Interval based on Final Hour-Ahead Schedules) at a per-MWh rate that shall not exceed a figure that is determined by dividing the total Minimum Load Cost in that~~

~~month by the sum of the minimum loads for Generating Units operating under Waiver Denial Periods in that month;~~

~~b. finally, all remaining costs not allocated per (a) shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's monthly Control Area Gross Load and Demand within California outside the ISO Control Area that is served by exports to the monthly sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators.~~

~~40.1.6.1.5 Payment Of Available Capacity Under The Must-Offer Obligation.~~

~~Available capacity that is required to be offered to the Real Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Minimum Load Cost compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period, as defined in Section 40.1.6.1.1, that the unit generated above minimum load in compliance with ISO Dispatch Instructions.~~

~~40.1.6.2 Criteria for Issuing Must-Offer Waivers.~~

~~The ISO shall grant waivers so as to: 1) provide sufficient on-line generating capacity to meet operating reserve requirements; and 2) account for other physical operating constraints, including Generating Unit minimum up and down times. The ISO shall grant, deny or revoke waivers using a security-constrained unit commitment software application to minimize start-up and Minimum Load Costs.~~

~~40.1.7 Requirement of Must-Offer Generators to File Heat Rate and Emissions Rate Data.~~

~~Must-Offer Generators, as defined in Section 40.1 of this ISO Tariff, that own or control gas-fired Generating Units must file with the ISO and the FERC, on a confidential basis, the heat rates and emissions rates for each gas-fired Generating Unit that they own or control. Heat rate and emissions rate data shall be provided in the format specified by the ISO as posted on the ISO Home Page. Heat rate data provided to comply with this requirement shall not include start-up or minimum load fuel costs. Must-Offer Generators must also file periodic updates of this data upon the direction of either FERC or the ISO. The ISO will treat the information provided to the ISO in accordance with this Section 40.1.7 as~~

~~confidential and will apply the procedures in Section 20.4 of this ISO Tariff with regard to requests for disclosure of such information.~~

~~40.1.8 Calculation of the Proxy Price.~~

~~The ISO shall calculate each day separate Proxy Prices for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator by applying the filed heat rates for those Generating Units to a daily proxy figure for natural gas costs with an additional $6/MWh allowed for operations and maintenance expenses. The proxy figures for natural gas costs shall be based on the most recent data available and shall be posted on the ISO Home Page by 8:00 AM on the day prior to which the figures will be used for calculation of the Proxy Price.~~

~~40.1.9 Emissions Costs.~~

~~40.1.9.1 Obligation to Pay Emissions Cost Charges.~~

~~Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Emissions Costs incurred by a Must-Offer Generator as a direct result of an ISO Dispatch instruction, in accordance with this Section 40.1.9. The ISO shall levy this administrative charge (the "Emissions Cost Charge") each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Emissions Cost Charges in accordance with the ISO Payments Calendar.~~

~~40.1.9.2 Emissions Cost Trust Account.~~

~~All Emissions Cost Charges received by the ISO shall be deposited in the Emissions Cost Trust Account. The Emissions Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.~~

~~40.1.9.3 Rate For the Emissions Cost Charge.~~

~~The rate at which the ISO will assess the Emissions Cost Charge shall be at the projected annual total of all Emissions Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instruction, adjusted for interest projected to be earned on the monies in the Emissions Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators for the~~

~~applicable year (“Emissions Cost Demand”). The initial rate for the Emissions Cost Charge, and all subsequent rates for the Emissions Cost Charge, shall be posted on the ISO Home Page.~~

~~40.1.9.4 Adjustment of the Rate For the Emissions Cost Charge.~~

~~The ISO may adjust the rate at which the ISO will assess the Emissions Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:~~

~~(a) the difference, if any, between actual Emissions Cost Demand and projected Emissions Cost Demand;~~

~~(b) the difference, if any, between the projections of the Emissions Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions and the actual Emissions Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions as invoiced to the ISO and verified in accordance with this Section 40.1.9; and~~

~~(c) the difference, if any, between actual and projected interest earned on funds in the Emissions Cost Trust Account.~~

~~The adjusted rate at which the ISO will assess the Emissions Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Home Page at least five (5) days in advance of the date on which the new rate shall go into effect.~~

~~40.1.9.5 Credits and Debits of Emissions Cost Charges Collected from Scheduling Coordinators.~~

~~In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Emissions Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.~~

~~40.1.9.6 Submission of Emissions Cost Invoices.~~

~~Scheduling Coordinators for Must-Offer Generators that incur Emissions Costs as a direct result of an ISO Dispatch instruction may submit to the ISO an invoice in the form specified on the ISO Home Page (the “Emissions Cost Invoice”) for the recovery of such Emissions Costs. Emissions Cost Invoices shall not include any Emissions Costs specified in an RMR Contract for a unit owned or controlled by a Must-~~

~~Offer Generator. All Emissions Cost Invoices must include a copy of all final invoice statements from air quality districts demonstrating the Emissions Costs incurred by the applicable Generating Unit, and such other information as the ISO may reasonably require to verify the Emissions Costs incurred as a direct result of an ISO Dispatch instruction.~~

~~40.1.9.7 Payment of Emissions Cost Invoices.~~

~~The ISO shall pay Scheduling Coordinators for all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction. If the Emissions Costs indicated in the applicable air quality districts' final invoice statements include emissions produced by operation not resulting from ISO Dispatch instructions, the ISO shall pay an amount equal to Emissions Costs multiplied by the ratio of the MWh associated with ISO Dispatch instruction to the total MWh associated with such Emissions Costs. The ISO shall pay Emissions Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Emissions Cost Trust Account. To the extent there are insufficient funds available in Emissions Cost Trust Account in any month to pay all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction, the ISO shall make pro rata payment of such Emissions Costs and shall adjust the rate at which the ISO will assess the Emissions Cost Charge in accordance with Section 40.1.9.4. Any outstanding Emissions Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Emissions Costs is limited to the obligation to pay Emissions Cost Charges received. All disputes concerning payment of Emissions Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.~~

~~40.1.10 Start-Up Costs.~~

~~40.1.10.1 Obligation to Pay Start-Up Cost Charges.~~

~~Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Start-Up Costs incurred by a Must-Offer Generator as a direct result of an ISO Dispatch instruction, in accordance with this Section 40.1.10. Such Start-Up Costs shall include (1) fuel and (2) auxiliary power. The ISO shall levy this charge (the "Start-Up Cost Charge"), each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within~~

~~California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Start-Up Cost Charges in accordance with the ISO Payments Calendar.~~

~~40.1.10.2 Start-Up Cost Trust Account.~~

~~All Start-Up Cost Charges received by the ISO shall be deposited in the Start-Up Cost Trust Account. The Start-Up Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.~~

~~40.1.10.3 Rate For the Start-Up Cost Charge.~~

~~The rate at which the ISO will assess the Start-Up Cost Charge shall be at the projected annual total of all Start-Up Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instruction, adjusted for interest projected to be earned on the monies in the Start-Up Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area ("Start-Up Cost Demand"). The initial rate for the Start-Up Cost Charge, and all subsequent rates for the Start-Up Cost Charge, shall be posted on the ISO Home Page.~~

~~40.1.10.4 Adjustment of the Rate For the Start-Up Cost Charge.~~

~~The ISO may adjust the rate at which the ISO will assess the Start-Up Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:~~

~~(a) the difference, if any, between actual Start-Up Cost Demand and projected Start-Up Cost Demand;~~

~~(b) the difference, if any, between the projections of the Start-Up Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions and the actual Start-Up Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions as invoiced to the ISO and verified in accordance with this Section 40.1.10; and~~

~~(c) the difference, if any, between actual and projected interest earned on funds in the Start-Up Cost Trust Account.~~

~~The adjusted rate at which the ISO will assess the Start-Up Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and~~

~~calculations used by the ISO as a basis for such an adjustment on the ISO Home Page at least five (5) days in advance of the date on which the new rate shall go into effect.~~

~~40.1.10.5 Credits and Debits of Start-Up Cost Charges Collected from Scheduling Coordinators.~~

~~In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Start-Up Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.~~

~~40.1.10.6 Submission of Start-Up Cost Invoices.~~

~~Scheduling Coordinators for Must-Offer Generators that incur Start-Up Costs as a direct result of an ISO Dispatch instruction or if the ISO revokes a waiver from compliance with the must-offer obligation while the unit is off-line in accordance with Section 40.1.6 of this ISO Tariff, and Scheduling Coordinators for Generating Units operating under Condition 2 of the relevant RMR Contract which are called out-of-market in accordance with Section 11.2.4.2 of this ISO Tariff may submit to the ISO an invoice in the form specified on the ISO Home Page (the "Start-Up Cost Invoice") for the recovery of such Start-Up Costs. Such Start-Up Costs shall not exceed the costs which would be incurred within the start-up time for a unit specified in Schedule 1 of the Participating Generator Agreement. Start-Up Cost Invoices shall use the applicable proxy figure for natural gas costs as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas. Start-Up Cost Invoices shall specify the amount of auxiliary power used during the start-up and the actual price paid for that power. Start-Up Cost Invoices shall not include any Start-Up Costs specified in an RMR Contract for a unit owned or controlled by a Must-Offer Generator.~~

~~40.1.10.7 Payment of Start-Up Cost Invoices.~~

~~The ISO shall pay Scheduling Coordinators for all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction. The ISO shall pay such Start-Up Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the~~

~~Start-Up Cost Trust Account. To the extent there are insufficient funds available in the Start-Up Cost Trust Account in any month to pay all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch instruction, the ISO shall make pro rata payment of such Start-Up Costs and shall adjust the rate at which the ISO will assess the Start-Up Cost Charge in accordance with Section 40.1.10.4. Any outstanding Start-Up Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Start-Up Costs is limited to the obligation to pay Start-Up Cost Charges received. All disputes concerning payment of Start-Up Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.~~

~~40.2 Procurement of RMR.~~

~~40.3 Assurance of Adequate Generation and Transmission to meet Applicable Operating and Planning Reserve.~~

~~40.3.1 Generation Planning Reserve Criteria.~~

~~Generation planning reserve criteria shall be met as follows:~~

~~40.3.1.1~~ ~~On an annual basis, the ISO shall prepare a forecast of weekly Generation capacity and weekly peak Demand on the ISO Controlled Grid. This forecast shall cover a period of twelve months and be posted on the WEnet and the ISO may make the forecast available in other forms at the ISO's option.~~

~~40.3.1.2~~ ~~If the forecast shows that the applicable WECC/NERC Reliability Criteria can be met during peak Demand periods, then the ISO shall take no further action.~~

~~40.3.1.3~~ ~~If the forecast shows that the applicable WECC/NERC Reliability Criteria cannot be met during peak Demand periods, then the ISO shall facilitate the development of market mechanisms to bring the ISO Controlled Grid during peak periods into compliance with the Applicable Reliability Criteria (or such more stringent criteria as the ISO may impose pursuant to Section 7.2.2.2). The ISO shall solicit bids for Replacement Reserve in the form of Ancillary Services, short-term Generation supply contracts of up to one (1) year with Generators, and Load curtailment contracts giving the ISO the right to reduce the Demands of those parties that win the contracts when there is insufficient Generation capacity to satisfy those Demands in addition to all other Demands. The curtailment contracts shall provide that the ISO's~~

~~curtailment rights can only be exercised after all available Generation capacity has been fully utilized unless the exercise of such rights would allow the ISO to satisfy the Applicable Reliability Criteria at lower cost, and the curtailment rights shall not be exercised to stabilize or otherwise influence prices for power in the Energy markets.~~

~~**40.3.1.4**~~ ~~If Replacement Reserve, short-term Generation supply contracts or curtailment contracts are required to meet Applicable Reliability Criteria, the ISO shall select the bids that permit the satisfaction of those Applicable Reliability Criteria at the lowest cost.~~

~~**40.3.1.5**~~ ~~Notwithstanding the foregoing, if the ISO concludes that it may be unable to comply with the Applicable Reliability Criteria, the ISO shall, acting in accordance with Good Utility Practice, take such steps as it considers to be necessary to ensure compliance, including the negotiation of contracts through processes other than competitive solicitations. The steps can include the negotiation of contracts for Ancillary Services on a real time basis. If the ISO is unable to obtain such Ancillary Services from within the ISO Controlled Grid, the ISO may solicit Ancillary Services from other Control Areas on a real-time basis.~~

~~**40.3.1.6**~~ ~~The ISO may, in addition to the required annual forecast, publish a forecast of the peak Demands and Generation resources for two or more additional years. This forecast would be for information purposes to allow Market Participants to take appropriate steps to satisfy the Applicable Reliability Criteria, and would not be used by the ISO to determine whether additional resources are necessary.~~

~~**40.3.1.7**~~ ~~In fulfilling its requirement to ensure that the applicable Generation planning reserve criteria are satisfied, the ISO shall rely to the maximum extent possible on market forces.~~

~~**40.3.1.8**~~ ~~Except where and to the extent that such costs are recovered from Scheduling Coordinators pursuant to Section 8, and except as provided in Section 40.3.1.9, all costs incurred by the ISO in any hour pursuant to any contract entered into under this Section 40.3.1 shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (including exports) bears to the total metered hourly Demand (including exports) served in that hour.~~

~~**40.3.1.9** Costs incurred by the ISO pursuant to any contract entered into under this Section 40.3.1 for resources to meet any portion of the anticipated difference between forward schedules and the real-time deviations from those schedules shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator's obligation for deviation Replacement Reserve in the hour, determined in accordance with Section 8.12.3A bears to the total deviation Replacement Reserve in that hour.~~