1. DEFINITIONS AND INTERPRETATION.

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2. ISO OPERATIONS.

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2.2.6.4 Trades between Scheduling Coordinators. [Not Used] ~~Billing and settling an Inter-Scheduling Coordinator Energy or Ancillary Service Trade shall be done in accordance with the agreements between the parties to the trade. The parties to an Inter-Scheduling Coordinator Energy or Ancillary Service Trade shall notify the ISO, in accordance with the ISO Protocols, of the Zone in which the transaction is deemed to occur, which, for Inter-Scheduling Coordinator Energy Trades, shall be used for the purpose of identifying which Scheduling Coordinator will be responsible for payment of applicable Usage Charges~~;

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2.2.6.8 Annual and Weekly Forecasts. Submitting to the ISO the forecaste~~d~~**s as provided for in the Demand Forecast Protocol;** ~~weekly peak Demand on the ISO Controlled Grid and the forecasted Generation capacity. The forecasts shall cover a period of twelve (12) months on a rolling basis;~~

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2.2.7.2 [Not Used] ~~**Submitting Balanced Schedules.** A Scheduling Coordinator shall submit to the ISO only Balanced Schedules in the Day-Ahead Market and the Hour-Ahead Market. A Schedule shall be treated as a Balanced Schedule when aggregate Generation, Inter-Scheduling Coordinator Energy Trades (whether purchases or sales), and imports or exports to or from external Control Areas adjusted for Transmission Losses as appropriate, equals aggregate forecast Demand with respect to all~~

~~entities for which the Scheduling Coordinator schedules in each Zone. If a Scheduling Coordinator submits a Schedule that is not a Balanced Schedule, the ISO shall reject that Schedule provided that Scheduling Coordinators shall have an opportunity to validate their Schedules prior to the deadline for submission to the ISO by requesting such validation prior to the applicable deadline.~~

* * *

2.2.8.1 <u>**[Not Used]**</u> ~~**Preferred Schedule.** A Preferred Schedule shall be 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 2.5.10 and, where they elect to self provide Ancillary Services pursuant to Section 2.5.20.1, an Ancillary Service schedule meeting the requirements set forth in Section 2.5.20.6. The Preferred Schedule shall also include an indication of which resources (Generation or Load) if any may be adjusted by the ISO to eliminate Congestion. On receipt of the Preferred Schedule in the Day-Ahead scheduling process, 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 2.2.11.3.4. If the ISO notifies a Scheduling Coordinator that there will be no Congestion on the ISO Controlled Grid and, subject to Section 2.2.11.3.4, the Preferred Schedule shall become that Scheduling Coordinator's Final Schedule.~~

2.2.8.2 <u>**[Not Used]**</u> ~~**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.~~

2.2.8.3 **[Not Used]** ~~**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. 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 2.2.11.3.4.~~

2.2.8.4 **[Not Used]** ~~**Final Schedules.** If the ISO notifies a Scheduling Coordinator that there will be no Congestion on the ISO Controlled Grid, the Revised Schedule shall become that Scheduling Coordinator's Final Schedule. If no Scheduling Coordinator submits any changes to the Suggested Adjusted Schedules, all of the Suggested Adjusted Schedules shall become the Final Schedules. The Final Schedules shall serve as the basis for Settlement between the ISO and each Scheduling Coordinator.~~

* **

2.2.10 **[Not Used]**~~**Information to be Provided by the ISO to all Scheduling Coordinfators.**~~

~~By 6:00 p.m. two days prior to a Trading Day, the ISO shall publish on WEnet information, including the following to all Scheduling Coordinators for each Settlement Period of the Trading Day:~~

2.2.10.1 **[Not Used]** ~~**Scheduled Line Outages.** Scheduled transmission line Outages;~~

2.2.10.2 **[Not Used]**

2.2.10.3 **[Not Used]** ~~**Forecast Loop-Flow.** Forecast Loop Flow over ISO Inter-zonal Interfaces and Scheduling Points;~~

2.2.10.4 **[Not Used]** ~~**Advisory Demand Forecasts.** Advisory Demand Forecasts by location;~~

2.2.10.5 **[Not Used]**~~**Updated Transmission Loss Factors.** Updated Generation Meter Multipliers reflecting Transmission Losses to be supplied by each Generating Unit and by each import into the ISO Control Area; and~~

2.2.10.6 **[Not Used]**~~**Ancillary Services.** Expected Ancillary Services requirement by reference to Zones for each of the reserve Ancillary Services.~~

2.2.10.7 **[Not Used]**

2.2.10.8 **[Not Used]**

2.2.11 Information to Be Submitted by Scheduling Coordinators to the ISO.

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:

2.2.11.1 **[Not Used]** ~~**For Load:**~~

2.2.11.1.1 **[Not Used]** ~~**Designated Location Code.** For all Load the Location Code of the Take-Out Point;~~

2.2.11.1.2 **[Not Used]**~~**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~~;

2.2.11.1.3 **[Not Used]**~~**Flexibility.** Whether the Preferred Schedule is flexible for adjustment to eliminate Congestion;~~

2.2.11.1.4 **[Not Used]~~Adjustment Bids.~~** ~~The MW and $/MWh values representing the Adjustment Bid curve for any Dispatchable Load.~~

2.2.11.2 **For Generation:**

2.2.11.2.1 **[Not Used]~~Location of Generating Units.~~** ~~The Location Code of all Generating Units scheduled, if applicable, or the source Control Area and Scheduling Point;~~

2.2.11.2.2 **[Not Used]~~Quantity Scheduled.~~** ~~The aggregate quantity (in MWh) being scheduled from each Generating Unit and System Resource;~~

2.2.11.2.3 **[Not Used]~~Notification of Flexibility.~~** ~~Notification of whether the Preferred Schedule is flexible for adjustment to eliminate Congestion~~;

2.2.11.2.4 **[Not Used]~~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;~~

2.2.11.2.5 **[Not Used]~~Operating Characteristics.~~** ~~Operating characteristics for each Generating Unit and System Resource for which an Adjustment Bid has been submitted; and~~

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

2.2.11.3 **[Not Used]~~For deliveries to/from other Scheduling Coordinators:~~**

2.2.11.3.1 **[Not Used]~~Identification Code.~~** ~~Identification Code of Scheduling Coordinator to which Energy is provided or from which Energy is received;~~

2.2.11.3.2 **[Not Used]~~Quantity of Energy.~~** ~~Quantity (in MWh) of Energy being received or delivered;~~

2.2.11.3.3 **[Not Used]~~Zone.~~** ~~The Zone within which Energy is deemed to be provided by one Scheduling Coordinator to another under the Inter-Scheduling Coordinator Energy Trades.~~

2.2.11.3.4 **[Not Used]** ~~**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 in accordance with the procedures detailed in the ISO Protocols.~~

2.2.11.3.5 **[Not Used]** ~~The Generating Unit or Dispatchable Load that the source or recipient of Energy traded.~~

2.2.11.3.6 **[Not Used]** ~~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.~~

2.2.11.4 **For Self Provided Ancillary Services:** Scheduling Coordinators electing to self provide Ancillary Services shall supply the information referred to in Section 2.5.20.5 in relation to each Ancillary Service to be self provided.

2.2.11.5 **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 2.5.3.2 to cover such Interruptible Imports or to purchase such Operating Reserve from the ISO.

2.2.12 Timing of Day-Ahead Scheduling.

2.2.12.1 The ISO may in its sole discretion waive the timing requirements of this Section 2.2 where necessary to preserve System Reliability. The ISO may also waive the timing requirements of Section 2.2 where, because of error or delay, the ISO is unable to meet the timing requirements. Any such waiver shall be published on WEnet.

2.2.12.2 **[Not Used]** ~~**Reliability Must Run Information.** By no later than two hours before the close of the PX Day-Ahead Market for 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".~~

2.2.12.2.1 **[Not Used]** ~~No later than one hour before the close of the PX Day-Ahead Market for the Trading Day, any RMR Owner receiving an RMR Dispatch Notice as indicated in this Section 2.2.12.2 (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, of, (i) the amount of its obligation to deliver RMR Energy that it intends to satisfy by delivering the RMR Energy pursuant to a market transaction, and receiving only market compensation therefor (the "RMR Market Energy"), and (ii) the amount of its obligation to deliver RMR Energy that it intends to satisfy by delivering the RMR Energy as a contract transaction, and accepting payment under the relevant RMR Contract (the "RMR Contract Energy"). 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.~~

2.2.12.2.2 **[Not Used]** ~~***RMR Contract Energy --*** For each hour specified in the RMR Dispatch Notice, the Applicable RMR Owner shall bid the entire amount of the RMR Contract Energy for that hour into the PX Day-Ahead Market at zero dollars per MWh, unless the Applicable RMR Owner is precluded from bidding into the PX because of law, regulation, the applicable PX rate schedule, or the unavailability of the PX Day-Ahead Market. All RMR Energy delivered under this option shall be deemed delivered under a Nonmarket Transaction for the purposes of the RMR Contract.~~

2.2.12.2.3 **[Not Used]** ~~***RMR Market Energy*** – For each hour specified in the RMR Dispatch Notice, the Applicable RMR Owner (i) may bid into the PX Day-Ahead Market any amount of the RMR Market Energy for that hour and (ii) may schedule as a bilateral Day-Ahead transaction any amount of RMR Energy for that hour.~~

2.2.12.2.3.1 **[Not Used]**

2.2.12.2.3.1.1 **[Not Used]** ~~The Preferred Day-Ahead Schedule of the Applicable RMR SC shall include as RMR Energy for each hour no less than the sum of the RMR Contract Energy for that hour and the amount of RMR Market Energy scheduled as a bilateral Day-Ahead transaction for that hour, unless the Applicable RMR Owner is required to bid the Contract Energy into the PX Day-Ahead Market and the amount awarded in the PX Day-Ahead Market is less than the amount of the RMR Contract Energy, in which case the Preferred Day-Ahead Schedule shall include the sum of that lesser amount and the amount of RMR Market Energy scheduled as a bilateral Day-Ahead transaction for that hour. If the Preferred Day-Ahead Schedule of the Applicable RMR SC for any hour includes Adjustment Bids for the RMR Unit, the Adjustment Bid shall specify the RMR Energy as the minimum MW output to which the Applicable RMR SC 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 SC shall be entitled to any payment from any source for RMR Energy that is not bid and scheduled as required by this Section 2.2.12.2.2. In the event that the RMR Energy is not delivered, (i) if the RMR Energy had been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and the Applicable RMR SC shall pay for the Imbalance Energy necessary to replace that RMR Energy, or (ii) if the RMR 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 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.~~

2.2.12.2.3.2 **<u>[Not Used]</u>** ~~If the Applicable RMR SC's Preferred Day-Ahead Schedule does not include the entire amount of RMR Energy for any hour, the Applicable RMR Owner shall bid all remaining RMR Energy for that hour, net of any RMR Market Energy the Applicable RMR Owner elects to provide through an Hour-Ahead bilateral transaction for that hour, into the next available PX Market for such hour at zero dollars per MWh.~~

2.2.12.2.3.2.1 **<u>[Not Used]</u>** ~~The Applicable RMR SC's Preferred Hour-Ahead Schedule for each hour shall include all RMR 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 PX Markets under Section 2.2.12.2.3.2 but was not awarded in such PX Markets for such hour. If the Preferred Hour-Ahead Schedule of the Applicable RMR SC for any hour includes Adjustment Bids for the RMR Unit, the Adjustment Bid shall specify the RMR Energy as the minimum MW output to which the Applicable RMR SC will allow the RMR Unit to be redispatched for that hour.~~

2.2.12.2.3.3 **<u>[Not Used]</u>** ~~Whether or not the RMR Energy is in the Final Preferred Schedule, the Applicable RMR Owner must deliver the RMR Energy pursuant to the RMR Dispatch Notice. If the amount of RMR Energy for any hour that is delivered is less than the amount specified for that hour in~~

~~the RMR Dispatch Notice, the RMR Energy delivered shall be deemed RMR Contract Energy in an amount not to exceed the amount that the Applicable RMR Owner elected to deliver as RMR Contract Energy for that hour; the remainder shall be deemed RMR Market Energy. Notwithstanding anything to the contrary in the RMR Contract, neither the Applicable RMR Owner nor the Applicable RMR SC shall be entitled to any payment from any source for RMR Energy that is not bid and scheduled as required by this Section 2.2.12.2. If the amount of RMR Energy for any hour that is bid and scheduled as required by this Section 2.2.12.2 is less than the amount of RMR Energy specified in the RMR Dispatch Notice for that hour, the RMR Energy bid and scheduled as required shall be deemed RMR Contract Energy in an amount not to exceed the amount that the Applicable RMR Owner elected to deliver as RMR Contract Energy; the remainder shall be deemed RMR Market Energy.~~

2.2.12.2.4 **[Not Used]** ~~If, at any time after two hours before the close of the PX Day-Ahead Market for 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"). No later than one hour before the close of the next PX Market for each hour specified in the Supplemental RMR Dispatch Notice, the Applicable RMR Owner must notify the ISO through the the Applicable RMR SC, with regard to each such hour, of (i) the amount of its obligation to deliver RMR Energy specified in the Supplemental RMR Dispatch Notice that it intends to satisfy by delivering RMR Contract Energy, and (ii) the amount of its obligation to deliver RMR Energy that it intends to satisfy by delivering RMR Market Energy. The Energy specified in the Supplemental Dispatch Notice shall be subject to the same bidding, scheduling, and delivery requirements and pricing provisions specified in this Section 2.2.12.2 as is RMR Energy not included in the Day-Ahead Schedule. If the ISO issues the Supplemental RMR Dispatch Notice less than two hours before the close of the last PX Market for any particular hour of the Trading Day, the Energy specified in the Supplemental Dispatch Notice for such particular hour shall be exempt from the bidding and scheduling requirements and the pricing provisions of this Section 2.2.12.2.~~

2.2.12.3 **[Not Used]** ~~**Non-PX Demand Information.** By 6:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator (other than the PX) shall provide to the ISO a Demand Forecast specified by UDC Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day. The ISO shall aggregate the Demand information by UDC Service Area and transmit the aggregate Demand information to each UDC serving such aggregate Demand.~~

2.2.12.4 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 **Energy** ~~Adjustment~~ Bids and Ancillary Services bids.

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

2.2.12.6 **[Not Used]** ~~**ISO Analysis of Preferred Schedules.** On receipt of the Preferred Schedules, the ISO will analyze the Preferred Schedules of Applicable RMR SCs to determine the compatibility of such Preferred Schedules with the RMR Dispatch Notices. 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 2.2.11.3.4. 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 2.2.11.3.4, the Preferred Schedules shall become the Final Schedules and the ISO shall notify Scheduling Coordinators accordingly.~~

2.2.12.7 **[Not Used]** ~~**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.~~

2.2.12.8 **[Not Used]** ~~**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 2.2.11.3.4.~~

2.2.12.8.1 **[Not Used]** ~~**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 2.2.11.3.4, the Revised Schedules and any unamended~~

~~Preferred Schedules shall become Final Day-Ahead Schedules and the ISO shall notify Scheduling Coordinators accordingly.~~

2.2.12.8.2 **[Not Used]** ~~**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 and the ISO Protocols to develop the Final Day-Ahead Schedules.~~

2.2.13 Timing of Hour-Ahead Scheduling.

2.2.13.1 **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~~ **Energy** Bids or Ancillary Services ~~B~~**b**~~B~~ids shall be submitted at least ~~two~~ **one** hour~~s~~ prior to the commencement of that ~~**Settlement Periodo**~~**operating hour** ~~Settlement Period~~.

2.2.13.1.1 **[Not Used]** ~~**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.~~

2.2.13.1.2 **[Not Used]** ~~**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.~~

2.2.13.2 **[Not Used]** ~~**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.~~

2.2.13.2.1 **[Not Used]** ~~**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.~~

2.2.13.2.2 [Not Used] ~~Congestion Management Provisions for Final Hour Ahead Schedules.~~ ~~If the ISO identifies Congestion, it shall use the Congestion Management provisions of Section 7.2 of this ISO Tariff and the ISO Scheduling Protocol to develop the Final Hour-Ahead Schedules.~~

2.2.13.2.3 ~~Unscheduled Demand.~~[Not Used]

2.2.13.2.3.1 [Not Used].~~Penalty on Unscheduled Demand.~~ ~~Any Scheduling Coordinator whose total metered Demand in a Zone in a Settlement Period exceeds the total Demand reflected in its Final Hour-Ahead Schedule by more than five (5) percent of such metered Demand shall pay the penalty set forth in Section 2.2.13.2.3.2 for each MWh of the excess, unless the Scheduling Coordinator's metered Demand is less than 200 MW, in which case the Scheduling Coordinator shall pay the penalty to the extent its metered Demand exceeds the Demand in its Final Hour-Ahead Schedule by more than ten (10) MWh.~~

2.2.13.2.3.2 [Not Used]~~Amount of Penalty.~~ ~~For each MW of unscheduled Demand subject to penalty as determined in accordance with Section 2.2.13.2.3.1, a Scheduling Coordinator shall pay a penalty equal to the lesser of: (a) two times the Market Clearing Price of Imbalance Energy; and (b) $100; but no less than $0. This penalty shall be payable in addition to any amounts payable for the purchase of Imbalance Energy.~~

2.2.13.2.3.3 [Not Used] ~~Allocation of Penalty Revenues.~~ ~~The revenues received by the ISO through the payment of the penalties described in Section 2.2.13.2.3.2 will be allocated in~~

~~proportion to metered Demand to those Scheduling Coordinators who do not incur penalties under Section 2.2.13.2.3.1 for the Settlement Period with respect to which the charges were assessed.~~

2.2.13.3 **Final Hour-Ahead Schedules.** The ISO shall inform each Scheduling Coordinator of its responsibilities to provide Ancillary Services in accordance with Section 2.5.21. 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 ~~be a Balanced Schedule and~~ contain the following information:

2.2.13.3.1 **Generation.**

2.2.13.3.1.1 Name and identification number of each Participating Generator appearing in the Final Schedule;

2.2.13.3.1.2 Location Code of each Generating Unit, System Resource and Scheduling Point;

2.2.13.3.1.3 The ~~changes in~~ final scheduled quantity (in MWh) for each such Generating Unit~~,~~ or System Resource~~ and scheduled vltage~~;

2.2.13.3.1.4 Notification if the scheduled Generation was adjusted~~ to resolve Congestion; and~~.

2.2.13.3.1.5 [Not Used]

2.2.13.3.2 **Load**

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

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

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

2.2.13.4 [Not Used] ***~~[Refer to Section 31.2.3.1.4.3]~~*** ~~**Usage Charges.** The ISO shall notify each Scheduling Coordinator of the applicable Usage Charge calculated in accordance with Section 7.3.~~

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2.3 System Operations under Normal and Emergency Operating Conditions.

2.3.1 ISO Control Center Operations.

2.3.1.1 ISO Control Center.

2.3.1.1.1 Establish ISO Control Center. The ISO shall establish a WSCC approved Control Area and control center to direct the operation of all facilities forming part of the ISO Controlled Grid, Reliability Must-Run Units and Generating Units providing **Energy and** Ancillary Services.

2.3.1.1.2 Establish Back-up Control Facility. The ISO shall establish back-up control facilities remote from the ISO Control Center sufficient to enable the ISO to continue to direct the operation of the ISO Controlled Grid, Reliability Must-Run Units and Generating Units providing **Energy and** Ancillary Services in the event of the ISO Control Center becoming inoperable.

2.3.1.1.3 ISO Control Center Authorities. The ISO shall have full authority, subject to Section 2.3.1.2 to direct the operation of the facilities referred to in Section 2.3.1.1.2 including (without limitation), to:

(a) direct the physical operation by the Participating TOs of transmission facilities under the Operational Control of the ISO, including (without limitation) circuit breakers, switches, voltage control equipment, protective relays, metering, and Load Shedding equipment;

(b) commit and dispatch **designated Capacity Resources and** Reliability Must-Run Units;

(c) order a change in operating status of auxiliary equipment required to control voltage or frequency;

(d) take any action it considers to be necessary consistent with Good Utility Practice to protect against uncontrolled losses of Load or Generation and/or equipment damage resulting from unforeseen occurrences;

(e) control the output of Generating Units that are selected to provide Ancillary Services and ~~Imbalance~~Energy;

(f) dispatch Loads through direct Load control or other means at the ISO's discretion that are curtailable as an Ancillary Service; and

(g) procure Supplemental Energy.

2.3.1.1.4 Coordination and Approval for Outages. The ISO shall have authority to coordinate and approve Outages and returns to service of all facilities comprised in the ISO Controlled Grid and Reliability Must-Run Units in accordance with Section 2.3.3.

2.3.1.1.5 Responsibility for Authorized Work on Facilities. The ISO shall have authority to approve requests by Participating TOs to work on all energized transmission equipment under the Operational Control of the ISO.

2.3.1.1.6 The ISO shall be the WSCC security coordinator for the ISO Controlled Grid.

2.3.1.2 Market Participant Responsibilities.

2.3.1.2.1 Comply with Operating Orders Issued. With respect to this Section 2.3.1.2, all Market Participants within the ISO Control Area **and all System Resources** shall comply fully and promptly with the ISO's operating orders, unless such operation would impair public health or safety. **In this regard, Final Hour-Ahead Schedules for Energy for Generating Units,**

System Resources, System Units and Dispatchable Loads are deemed to be operating orders. As such these Schedules are binding obligations and must be fulfilled unless otherwise directed by the ISO. Any Hour-Ahead Ancillary Services Schedule or Supplementary Energy Bid is a binding obligation, and a resource so scheduled or bid cannot be made unavailable or otherwise fail to respond to ISO operating orders except for conditions beyond the control of the resource owner. Any Day-Ahead commitment of a resource, either self-scheduled or committed in an ISO Energy market or through an ISO Residual Unit Commitment Process is a binding obligation, and such resource cannot be de-committed or otherwise made unavailable except for conditions beyond the control of the resource owner or as approved by the ISO. For this purpose ISO operating orders to shed Load shall not be considered as an impairment to public health or safety.

* * *

2.3.2.3.2 Before any such intervention the ISO must ~~(in the following order)~~: (a) dispatch all scheduled Generation and all other Generation offered or available to it regardless of price (including all ~~Adjustment Bids, Supplemental~~ Energy bids and~~,~~ Ancillary Services and ~~reserves~~); (b) dispatch all interruptible loads made available by UDCs to the ISO in accordance with the relevant agreements with UDCs; (c) dispatch or curtail all price-responsive Demand that has been bid into any of the markets and exercise its rights under all load curtailment contracts available to it; (d) exercise Load Shedding to curtail Demand on an involuntary basis to the extent that the ISO considers necessary.

2.3.2.3.3 The Administrative Price in relation to each of the markets for Imbalance Energy and Ancillary Services shall be set at the applicable Locational Marginal Price or Ancillary Services Marginal Price ~~Market Clearing Price~~ in the Settlement Period immediately preceding the Settlement Period in which the intervention took place. When Administrative Prices are imposed, ~~Inter Zonal~~ Congestion will be managed in accordance with DP 8.5 of the Dispatch Protocol.

* * *

2.3.2.8.2 Load Curtailment. A Scheduling Coordinator may specify that Loads will be reduced at specified Market Clearing Prices or offer the right to exercise Load curtailment to the ISO as an Ancillary Service or utilize Load curtailment itself (by way of self provision of Ancillary Services) as Non-Spinning Reserve~~ or Replacement Reserve~~. The ISO, at its discretion, may require direct control over such Curtailable Demand to assume response capability for managing System Emergencies. However, non-firm Loads shall not be eligible to provide Curtailable Demand if they are receiving incentives for interruption under existing programs approved by a Local Regulatory Authority, unless: a) participation in the ISO's Ancillary Services markets is specifically authorized by such Local Regulatory Authority, and b) there exist no contingencies on the availability, nor any unmitigated incentives encouraging prior curtailment, of such interruptible Load for Dispatch as Curtailable Demand as a result of the operation of such existing program. The ISO may establish standards for automatic communication of curtailment instructions to implement Load curtailment as a condition for accepting any offered Curtailable Demand as an Ancillary Service.

* * *

2.3.2.9.3 Imposing Sanctions. If the ISO finds that the operation and maintenance practices of any Participating TOs, Participating Generators, Eligible Customers, or UDCs prolonged the response time or contributed to the Outage, the ISO may impose sanctions on the responsible Participating TOs, Participating Generators, Eligible Customers, or UDCs provided that no sanction shall be imposed in respect of actions taken in compliance with the ISO's instructions or pursuant to a Remedial Action Scheme. The ISO shall develop and file with

FERC a schedule of such sanctions. Any dispute concerning whether sanctions should be imposed under this Section shall be resolved through the ISO ADR Procedures. The schedule of sanctions filed with FERC (including categories and levels of sanctions) shall not be subject to the ISO ADR Procedures. The ISO shall publish on the ISO Home Page~~t~~ details of all instances in which a sanction has been imposed.

* * *

2.3.3.5.3 Where, in the reasonable opinion of the ISO Outage Coordination Office, the requested Maintenance Outage or requested change to an Approved Maintenance Outage is likely to have a detrimental effect on the efficient use and reliable operation of the ISO Controlled Grid **or the adequacy of reserves in the ISO Control Area**, the ISO Outage Coordination Office may reject the requested Maintenance Outage or requested change to Approved Maintenance Outage. The determination of the ISO Outage Coordination Office shall be final and binding on the Operator. If, within fourteen (14) days of having made its determination, the Operator requests the ISO Outage Coordination Office to provide reasons for its determination, it shall do so as soon as is reasonably practicable. The ISO will give reasons for informational purposes only and without affecting in any way the finality or validity of the determination.

* * *

2.3.3.9.5 Within forty-eight (48) hours of the commencement of a Forced Outage, the Operator shall provide to the ISO an explanation of the Forced Outage, including a description of the equipment failure or other cause and a description of all remedial actions taken by the Operator. Upon request of the ISO, Operators, and where applicable, Eligible Customers, Scheduling Coordinators, UDCs and MSSs promptly shall provide information requested by the ISO to enable the ISO to review the explanation submitted by the Operator and to prepare reports on Forced Outages. If the ISO determines that any Forced Outage may have been the result of gaming or other questionable behavior by the Operator, the ISO shall submit a report describing the basis for its determination to the FERC. The ISO shall consider the following factors when evaluating the Forced Outage to determine if the Forced Outage was the result of gaming or other questionable behavior by the operator: 1) if the Forced Outage coincided with certain market conditions such that the Forced Outage may have influenced market prices or the cost of payments associated with **Exceptional** ~~out-of-sequence dispatches, out-of-market~~ **D**~~d~~ispatches, or **other** Real Time Market dispatches ~~above the Marginal Proxy Clearing Price or Non-Emergency Clearing Price Limit, as applicable~~; 2) if the Forced Outage coincided with a change in the bids submitted for any units or resources controlled by the Operator or the Operator's Scheduling Coordinator; 3) if the ISO had recently rejected a request for an outage for, or to shut down, the Generating Unit experiencing the Forced Outage; 4) if the timing or content of the notice of the Forced Outage provided to the ISO was inconsistent with subsequent reports of or the actual cause of the outage; 5) if the Forced Outage or the duration of the Forced Outage was inconsistent with the history or past performance of that Generating Unit or similar Generating Units; 6) if the Forced Outage created or exacerbated congestion; 7) if the Forced Outage was extended with little or no notice; 8) if the Operator had other alternatives to resolve the problems leading to the Forced Outage; 9) if the Operator took reasonable action to minimize the duration of the Forced Outage; or 10) if the Operator failed to provide the ISO an explanation of the Forced Outage within forty-eight (48) hours or failed to provide any additional information or access to the generating facility requested by the ISO within a reasonable time.

* * *

2.3.4 Management of Overgeneration Conditions.

The ISO shall use default Energy Bids as set forth in Section 31.2.3.1.4.2 in SCUC to adjust Schedules to manage Overgeneration in the Day-Ahead and Hour-Ahead Energy Markets. ~~The~~

~~ISO's management of overgeneration relates only to real time.~~ Overgeneration in real time will be mitigated by the ISO as follows; provided that the ISO operator will have the discretion, if necessary to avoid a system emergency, to eliminate one or more of the following steps.

* * *

2.3.4.3 In addition to the action taken under 2.3.4.2, the ISO will, if it considers it necessary to maintain the reliable operation of the ISO Control Area, offer Energy for sale on behalf of Scheduling Coordinators to adjacent Control Area operators at the ~~estimated~~ **Dispatch Interval Locational Marginal Price** ~~BEEP Interval Ex Post Price~~ or, if the ISO considers it necessary, at a price established by the ISO on behalf of Scheduling Coordinators, to be paid to adjacent Control Area operators.

* * *

2.3.5.1.3 If the forecast shows that the applicable WSCC/NERC Reliability Criteria cannot be met during peak Load 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 2.3.1.3.2). The ISO shall solicit bids for ~~Replacement R~~reserves 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 Loads of those parties that win the contracts when there is insufficient Generation capacity to satisfy those Loads in addition to all other Loads. 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.

2.3.5.1.4 If ~~Replacement R~~reserves, 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.

* * *

2.3.5.1.9 Costs incurred by the ISO pursuant to any contract entered into under this Section 2.3.5.1 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 **the same way Residual Unit Commitment costs are allocated as set forth in Section 5.12.8.** ~~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 2.5.28.4 bears to the total deviation Replacement Reserve in that hour.~~

* * *

2.4.4.4.4.1 The holders of Existing Rights **shall not be charged the Locational Marginal Price at the Sink or paid the Locational Marginal Price at the Source for their Final Day-Ahead or Final Hour-Ahead Energy Schedules associated with Existing Rights.**~~will not be responsible for paying Usage Charges related to those rights, nor will they be entitled to receive Usage Charge revenues related to those rights.~~

* * *

2.5 Ancillary Services.

2.5.1 Scope.

The ISO shall be responsible for ensuring that there are sufficient Ancillary Services available to maintain the reliability of the ISO Controlled Grid consistent with WSCC and NERC criteria. The

ISO's Ancillary Services requirements may be self provided by Scheduling Coordinators. Those Ancillary Services which the ISO requires to be available but which are not being self provided will be competitively procured by the ISO from Scheduling Coordinators in the Day-Ahead Market, Hour-Ahead Market and in real time or by longer term contracts. The ISO will manage both ISO procured and self provided Ancillary Services as part of the real time dispatch. The ISO will calculate payments for Ancillary Services to Scheduling Coordinators and charge the cost to Scheduling Coordinators.

For purposes of this ISO Tariff, Ancillary Services are: (i) Regulation, (ii) Spinning Reserve, (iii) Non-Spinning Reserve, (iv) ~~Replacement Reserve, (v)~~ Voltage Support, and (v~~i~~) Black Start capability. Bids for Non-Spinning Reserve and Replacement Reserve may be submitted by the Demand-side as well as by owners of Generation. Identification of specific services in this ISO Tariff shall not preclude development of additional interconnected operation services over time. The ISO and Market Participants will seek to develop additional categories of these unbundled services over time as the operation of the ISO Controlled Grid matures.

2.5.2 Ancillary Services Standards.

All Ancillary Services shall meet the ISO's Ancillary Services standards.

2.5.2.1 Determination of Ancillary Service Standards. The ISO shall set the required standard for each Ancillary Service necessary to maintain the reliable operation of the ISO Controlled Grid. Ancillary Services standards shall be based on WSCC Minimum Operating Reliability Criteria (MORC) and ISO Controlled Grid reliability requirements. The ISO Grid Operations Committee, in conjunction with the relevant reliability council (WSCC), shall develop these Ancillary Services standards to determine reasonableness, cost effectiveness, and adherence to national and WSCC standards. The standards developed by the ISO shall be used as a basis for determining the quantity and type of each Ancillary Service which the ISO requires to be available.

2.5.2.2 Time-frame For Revising Ancillary Service Standards. The ISO Technical Advisory Committee shall periodically undertake a review of the ISO Controlled Grid operation to determine any revision to the Ancillary Services standards to be used in the ISO Control Area. At a minimum the ISO Grid Operations Committee shall conduct such reviews to accommodate revisions to WSCC and NERC standards. The ISO may adjust the Ancillary Services standards temporarily to take into account, among other things variations in system conditions, real time dispatch constraints, contingencies, and voltage and dynamic stability assessments. Where practicable, the ISO will provide notice, via the ISO Home Page, of any temporary adjustments to Ancillary Service standards **as set forth in Scheduling Protocol Section 3.2.1** ~~by 6:00 p.m. two days ahead of the Trading Day to which the adjustment will apply~~.

2.5.3 Quantities of Ancillary Services Required.

For each of the Ancillary Services, the ISO shall determine the quantity and **Ancillary Service Region** ~~and location~~ of the Ancillary Service which is required and which must be under the direct Dispatch control of the ISO on an hourly basis each day. The ISO shall determine the quantities it requires as follows:

2.5.3.1 Regulation Service. The ISO shall maintain sufficient Generating Units immediately responsive to AGC in order to provide sufficient Regulation service to allow the system to meet WSCC and NERC criteria.

2.5.3.2 Spinning And Non-Spinning Reserves. The ISO shall maintain minimum contingency Operating Reserve made up of Spinning Reserve and Non-Spinning Reserve in accordance with WSCC MORC criteria equal to (a) 5% of the Demand to be met by Generation from hydroelectric resources plus 7% of the Demand to be met by Generation from other resources, or (b) the single largest Contingency, if this is greater or (c) by reference to such more stringent criteria as the ISO may determine from time to time. When the level of Operating Reserve is determined by Demand, the ISO shall not maintain Operating Reserve with respect to Demand covered by firm purchases from outside the ISO Control Area. In addition, the ISO shall maintain Operating Reserve equal to the total amount of Interruptible Imports scheduled by Scheduling Coordinators for any hour. Such additional Operating Reserve must either be self-provided or purchased from the ISO by Scheduling Coordinators. To the extent such additional Operating Reserve is self-provided by a Scheduling Coordinator, it may consist entirely of Non-Spinning Reserve. To the extent that such additional Operating Reserve is not self-provided by a Scheduling Coordinator, the ISO will procure the necessary amounts of Operating Reserve, but not necessarily entirely from Non-Spinning Reserves.

2.5.3.3 **[Not Used]** ~~**Replacement Reserve.** The ISO shall make its determination of the required quantity of Replacement Reserve based on:~~

~~(a) historical analysis of the deviation between actual and Day-Ahead forecast Demand,~~

~~(b) historical patterns of unplanned Generating Unit Outages,~~

~~(c) historical patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand,~~

~~(d) historical patterns of unexpected transmission Outages, and~~

~~(e) such other factors affecting the ability of the ISO to maintain System Reliability as the ISO may from time to time determine.~~

~~The ISO shall have discretion to determine the quantity of Replacement Reserve it requires in each Zone.~~

2.5.3.4 Voltage Support.

The ISO shall determine on an hourly basis for each day the quantity and location of Voltage Support required to maintain voltage levels and reactive margins within WSCC and NERC criteria using a power flow study based on the quantity and location of scheduled Demand. The ISO shall issue daily voltage schedules, which are required to be maintained for ISO Controlled Grid reliability. All other Generating Units shall comply with the power factor requirements set forth in contractual arrangements in effect on the ISO Operations Date, or, if no such contractual arrangements exist and the Generating Unit exists within the system of a Participating TO, the power factor requirements applicable under the Participating TO's TO Tariff or other tariff on file with the FERC.

All Participating Generators shall maintain the ISO specified voltage schedule at the transmission interconnection points to the extent possible while operating within the power factor range specified in their interconnection agreements or, for Regulatory Must-Take Generation, Regulatory Must-Run Generation and Reliability Must-Run Generation consistent with existing obligations. For Generating Units, that do not operate under one of these agreements, the minimum power factor range will be within a band of 0.90 lag (producing VARs) and 0.95 lead (absorbing VARs) power factors. Participating Generators with Generating Units existing at the ISO Operations Date that are unable to meet this operating power factor requirement may apply to the ISO for an exemption. Prior to granting such an exemption, the ISO shall require the Participating TO or UDC to whose system the relevant Generating Units are interconnected to notify it of the existing contractual requirements for voltage support established prior to the ISO Operations Date for such Generating Units. Such requirements may be contained in CPUC Electric Rule 21 or the Interconnection Agreement with the Participating TO or UDC. The ISO shall not grant any exemption under this Section from such existing contractual requirements.

The ISO shall be entitled to instruct Participating Generators to operate their Generating Units at specified points within their power factor ranges. Generators shall receive no compensation for operating within these specified ranges.

If the ISO requires additional Voltage Support, it shall procure this either through Reliability Must-Run Contracts or Capacity Resources~~ACAP resources~~ or, if no other more economic sources are available by instructing a Generating Unit to move its MVar output outside its mandatory range. Only if the Generating Unit must reduce its MW output in order to comply with such an instruction will it be compensated in accordance with Section 2.5.18.

All Loads directly connected to the ISO Controlled Grid shall maintain reactive flow at grid interface points within a specified power factor band of 0.97 lag to 0.99 lead. Loads shall not be compensated for the service of maintaining the power factor at required levels within the bandwidth. A UDC interconnecting with the ISO Controlled Grid at any point other than a Scheduling Point shall be subject to the same power factor requirement.

The power factor for both the Generating Units and Loads shall be measured at the interconnection point with the ISO Controlled Grid. The ISO will develop and will be authorized to levy penalties against Participating Generators, UDCs or Loads whose Voltage Support does not comply with the ISO's requirements. The ISO will establish voltage control standards with UDCs and the operators of other Control Areas and will enter into operational agreements providing for the coordination of actions in the event of a voltage problem occurring.

Wheeling Through and Wheeling Out transactions may also be subject to a reactive charge as developed by the ISO. If the ISO shall determine that a reactive charge should be payable at a future date, it shall, subject to FERC acceptance and approval, publish annually the Voltage Support obligations and applicable charges for Wheeling Through and Wheeling Out transactions at Scheduling Points. The obligations shall be predetermined by the ISO based on the estimated amount of the Wheeling Through and Wheeling Out transactions each year.

2.5.3.5 Black Start Capability. The ISO shall determine the amount and location of Black Start Generation it requires through contingency studies that are used as the basis of the ISO's emergency plans. The studies shall specify:

(a) the initiating disturbance;

(b) the magnitude of the Outage, including the extent of the Outage (local area, ISO Controlled Grid, or WSCC), the assumed status of Generation after the initiating disturbance, the status of interconnections, the system load level at the time of the disturbance, the interconnection support, and assumptions regarding the availability of support from other utilities to help restore Generation and Demand;

(c) the Generator performance including a percentage of Black Start units (to be determined by the ISO) which are expected to fail to start, and

(d) expected transmission system damage.

The ISO shall also specify the following load restoration performance goals:

(i) Black Start unit ~~startup~~start-up and connection times;

(ii) ISO Controlled Grid restoration times; and

(iii) load restoration times.

Scheduling Coordinators shall provide the ISO with their load restoration time requirements for any Loads that provide emergency services.

2.5.3.6 The ISO, whenever possible, will increase its purchases of an Ancillary Service that can substitute for another Ancillary Service, when doing so is expected to reduce its total cost of procuring Ancillary Services while meeting reliability requirements. The ISO will make such adjustments in accordance with the following principles:

(a) The Regulation requirement must be satisfied by Regulation bids from Resources qualified to provide Regulation;

(b) Additional Regulation capacity can be used to satisfy requirements for any type of reserves (Spinning Reserve **or** Non-Spinning Reserve~~ or Replacement Reserve~~);

(c) Regulation and Spinning Reserve requirements must be satisfied by the combination of Regulation and Spinning Reserve bids;

(d) Additional Regulation and Spinning Reserve capacity can be used to satisfy requirements for Non-Spinning ~~and Replacement~~ Reserve~~, except that any Spinning Reserve capacity that 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 cannot be used to satisfy requirements for Replacement Reserve~~;

(e) Regulation, Spinning Reserve, Non-Spinning Reserve requirements must be satisfied by the combination of Regulation, Spinning Reserve and Non-Spinning Reserve bids;

(f) ~~Additional Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve capacity can be used to satisfy requirements for Replacement Reserve except that any Spinning and Non-Spinning Reserve capacity that 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 cannot be used to satisfy requirements for Replacement Reserve;~~

~~(fg)~~ Total MW purchased from the Regulation, Spinning Reserve and, Non-Spinning Reserve~~, and Replacement Reserve~~ markets will not be changed by this Section 2.5.3.6; and

(gh) All quantities of Ancillary Services so procured must be non-negative.

2.5.4 Locational Quantities of Ancillary Services.

For each of the Ancillary Services, the ISO shall determine the required locational dispersion in accordance with ISO Controlled Grid reliability requirements. **The designation of Ancillary Service Regions shall reflect the required locational dispersion.** These standards shall be used as guidance only. The actual location of Ancillary Services on a daily and hourly basis shall depend on the locational spread of Demand within the ISO Control Area, the A~~a~~vailable T~~t~~ransmission C~~c~~apacity, the locational mix of Generation, and historical patterns of transmission and Generation availability.

2.5.4.1 Black Start Units.

(a) must be located in the ISO Control Area;

(b) may be located anywhere in the ISO Control~~led~~ Area provided that the Black Start resource is capable of meeting the ISO performance requirements for starting and interconnection to the ISO Controlled Grid; but

(c) must be dispersed throughout the ISO Control Area.

2.5.5 Time-frame For Contracting for Ancillary Services.

The ISO shall procure on a daily and hourly basis, each day, Regulation, Spinning **and,** Non-Spinning~~ and Replacement~~ Reserves. The ISO shall procure reserves~~Replacement Reserve~~ on a longer term basis pursuant to Section 2.3.5.1.3 if necessary to meet reliability criteria. The

ISO Governing Board must approve all long term reserve~~Replacement Reserve~~ contracts. The ISO shall contract for Voltage Support annually (or for such other period as the ISO may determine is economically advantageous) and on a daily or hourly basis as required to maintain S~~s~~ystem R~~r~~eliability. The ISO shall contract annually (or for such other period as the ISO may determine is economically advantageous) for Black Start Generation.

2.5.6 Technical Requirements for Providing Ancillary Services.

All Generating Units, System Units, Loads and System Resources providing Ancillary Services shall comply with the technical requirements set out in Sections 2.5.6.1 to 2.5.6.4 below relating to their operating capabilities, communication capabilities and metering infrastructure. No Scheduling Coordinator shall be permitted to submit a bid to the ISO for the provision of an Ancillary Service from a Generating Unit, System Unit, Load or System Resource, or to submit a schedule for self provision of an Ancillary Service from that Generating Unit, System Unit, Load or System Resource, unless the Scheduling Coordinator is in possession of a current certificate issued by the ISO confirming that the Generating Unit, System Unit, Load or System Resource complies with the ISO's technical requirements for providing the Ancillary Service concerned. Scheduling Coordinators can apply for Ancillary Services certificates in accordance with the ISO’s Protocols for considering and processing such applications. The ISO shall have the right to inspect Generating Units, Loads or the individual resources comprising System Units and other equipment for the purposes of the issue of a certificate and periodically thereafter to satisfy itself that its technical requirements continue to be met. If at any time the ISO’s technical requirements arenot being met, the ISO may withdraw the certificate for the Generating Unit, System Unit, Load or System Resource concerned.

2.5.6.1 Operating Characteristics Required to Provide Ancillary Services. Each Generating Unit, System Unit, Load or System Resource which a Scheduling Coordinator wishes to schedule or bid to provide Ancillary Services must comply with the requirements for the specific Ancillary Service in regard to the following:

(a) ramp rate increase and decrease **over the operating range of the resource** (MW/minute);

(b) power factor (leading and lagging) as required by Section 2.5.3.4;

(c) maximum output (real and reactive), except that System Resources shall be required to comply only with the requirement for maximum real power;

(d) minimum output (real and reactive), except that System Resources shall be required to comply only with the requirement for minimum real power;

(e) AGC capability, control scheme, and range; and

(f) minimum length of time the resource can be available to provide the relevant Ancillary Service.

The ISO will **specify** ~~differentiate~~ the operating characteristics **necessary to provide each Ancillary Service in the Ancillary Services Requirements Protocol**.~~according to the Ancillary Service being provided~~.

* * *

2.5.7.2 ~~Usage Charge in~~ Accounting for Congestion in Ancillary Service Bid Evaluation.

~~As of the ISO Operations Date,~~ **T**~~t~~he ISO will **account for Congestion** ~~not incorporate forecast Usage Charges into~~ **in** its Ancillary Service bid evaluations **as set forth in Section 31.2.3.1.4.4** ~~the means to evaluate Ancillary Service bids across Zones when Congestion is present~~.

* * *

2.5.7.4.2 Scheduling Coordinators may bid or self-provide external imports of Spinning Reserve or~~,~~ Non-Spinning Reserve~~ or Replacement Reserve~~ from resources located outside the ISO Control Area, where technically feasible and consistent with WSCC criteria; and provided that such Scheduling Coordinators have certified to the ISO their ability to deliver the service to the point of interchange with the ISO Control Area (including with respect to their ability to make changes, or cause such changes to be made, to interchange schedules during any interval of a Settlement Period at the discretion of the ISO).

* * *

2.5.9 Provision of System Information to Scheduling Coordinators.

By 6:00 p.m. two days prior to the Trading Day, the ISO shall make available to Scheduling Coordinators general system information including those items of information set forth in Section **<u>31.1</u>** ~~2.2.10~~. This information shall be provided at the same time as the ISO provides general system information to all Scheduling Coordinators wishing to schedule power on the ISO Controlled Grid.

2.5.10 Time Frame for Submitting And Evaluating Bids.

2.5.10.1 Day-Ahead Auction. Bids for the ISO's Day-Ahead Regulation, Spinning Reserve **<u>and</u>**~~,~~ Non-Spinning Reserve~~ and Replacement Reserve~~ service market must be received by 10:00 am on the day prior to the Trading Day. The bids shall include information for each ~~of the twenty-four (24)~~ Settlement Periods of the Trading Day. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO.

2.5.10.2 Hour-Ahead Auction. Bids for the ISO's Hour-Ahead Regulation, Spinning Reserve **<u>and</u>**~~,~~ Non-Spinning Reserve~~ and Replacement Reserve~~ service market for each Settlement Period must be received at least **<u>one hour</u>**~~two hours~~ prior to the commencement of that

Settlement Period. The bids shall include information for only the relevant Settlement Period. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO. Scheduling Coordinators wishing to buy back in the Hour-Ahead Market Regulation, Spinning Reserve, **or** Non-Spinning Reserve~~ or Replacement Reserve~~ capacity sold to the ISO in the Day-Ahead Market pursuant to section 2.5.21 must do so by submitting a revised bid in the Hour-Ahead Market for the Ancillary Service and resource concerned.

2.5.11 Information To Be Submitted By Bidders.

Bids shall be submitted by Scheduling Coordinators acting on behalf of Participating Generators, and owners or operators of Loads. Bids must be in the format specified by the ISO and include the bid information for each service described in the Schedules and Bids Protocol~~Sections 2.5.14 to 2.5.19~~ and such other information as the ISO may determine it requires to evaluate bids as published from time to time in ISO Protocols. The ISO will verify and respond to submitted bid data in accordance with Appendix E and the ISO Protocols. Bidders may submit new bids on a daily basis (or hourly basis for the Hour-Ahead Market).

2.5.12 Bid Evaluation Rules.

Bid evaluation shall be based on the following principles:

(a) the ISO shall not differentiate between bidders other than through price and capability to provide the service, and the required locational mix of services;

(b) to minimize the costs to users of the ISO Controlled Grid, the ISO shall select the bidders with lowest bids for capacity which meet its technical requirements, including location and operating capability;

(c) for the Day-Ahead Market, the Day-Ahead bids shall be evaluated **over the SCUC time horizon as set forth in Section 31.2.3.1.2.2**.~~independently for each of the 24 Settlement Periods of the following Trading Day~~;

(d) for the Hour-Ahead Market, the ISO shall evaluate bids **over the SCUC time horizon as set forth in Section 31.3.2**~~in the two hours preceding the hour of operation~~;

(e) the ISO will procure sufficient Ancillary Services in the Day Ahead Market to meet its forecasted requirements, as known at the close of the Day-Ahead Market, except that the ISO may elect to procure a portion of such requirements in the Hour-Ahead Markets if the ISO first provides notice to Scheduling Coordinators of such action, including the approximate hourly megawatt amounts of each Ancillary Service that it intends to procure in the Hour-Ahead Markets.

2.5.13 Evaluation of Ancillary Services Bids.

When Scheduling Coordinators bid into the Regulation, Spinning Reserve **and**~~,~~ Non-Spinning Reserve ~~and Replacement Reserve~~ markets, they may bid the same capacity into as many of these markets as desired by providing the appropriate bid information to the ISO. **Scheduling Coordinators shall submit Ancillary Services Bids in accordance with the Schedules and Bids Protocol.** The ISO shall evaluate bids in the markets for Regulation, Spinning Reserve **and**~~,~~ Non-Spinning Reserve ~~and Replacement Reserve~~ **simultaneously as set forth in Section 31.2.3.1.3**.~~sequentially and separately in the following order: Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve. Any capacity accepted by the ISO in one of these markets shall not be passed on to another market, except that capacity accepted in the Regulation market that represents the downward range of movement accepted by the ISO may be passed on to another market; any losing bids in one market may be passed onto~~

~~another market, if the Scheduling Coordinator so indicates to the ISO~~. A Scheduling Coordinator may specify capacity bid into only the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices~~ and different Energy prices~~ for the Spinning Reserve, Non-Spinning Reserve, ~~Replacement Reserve~~ and Regulation markets. ~~The bid information, bid evaluation and price determination rules set forth below shall be used in the Day-Ahead, Hour-Ahead and real time procurement of Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve~~.

A Scheduling Coordinator providing one or more Regulation, Spinning Reserve or~~,~~ Non-Spinning Reserve~~, and Replacement Reserve~~ services may not change the identification of the Generating Units or Loads offered in the Day-Ahead Market, the Hour-Ahead Market or in real time for such services unless specifically approved by the ISO.

2.5.14 [Not Used] ~~The Regulation Auction.~~

~~**Bid Information**. Each Scheduling Coordinator j shall submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:~~

~~(a) bidder name/Identification Code;~~

~~(b) resource identification (name and Location Code);~~

~~(c) the date for which the bid applies;~~

~~(d) maximum operating level (MW);~~

~~(e) minimum operating level (MW);~~

~~(f) ramp rate (MW/Min) $Ramp_{ijt}$;~~

~~(g) the upward and downward range of generating capacity over which Generating Unit or System Unit i from Scheduling Coordinator j is willing to provide Regulation for~~

~~Settlement Period t (~~$\cancel{Cap_{ijt}max}$ ~~(MW) where~~ $\cancel{Cap_{ijt}max \leq \text{Period}_{minutes} * Ramp_{ijt}}$. ~~Period~~ $\cancel{_{minutes}}$ ~~is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes. Bidders shall offer upward and downward range for Regulation service;~~

~~(h) the bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down (~~$\cancel{CapRes_{ijt}}$ ~~($/MW));~~

~~(i) the bid price of the Energy output from the reserved capacity (~~$\cancel{EnBid_{ijt}}$~~($/MWh));~~

~~If the bid is for the provision of Regulation from an external import of a System Resource, each Scheduling Coordinator j shall submit the following information for each System Resource i for each Settlement Period t of the following Trading Day:~~

~~(a) bidder name/Identification Code;~~

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

~~(c) Scheduling Point;~~

~~(d) interchange ID code;~~

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

~~(f) Schedule ID (NERC ID number) and complete WSCC tag;~~

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

~~(h) the contract reference number, if applicable;~~

~~(i) maximum operating level (MW);~~

~~(j) minimum operating level (MW);~~

~~(k) ramp rate (MW/Min) $Ramp_{ijt}$;~~

~~(l) the upward and downward range of generating capacity over which System Resource i from Scheduling Coordinator j is willing to provide Regulation for Settlement Period t ($Cap_{ijt}max$ (MW)) where $Cap_{ijt}max \leq Period_{minutes} * Ramp_{ijt}$. $Period_{minutes}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes. Bidders shall offer upward and downward range for Regulation service;~~

~~(m) the bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($CapRes_{ijt}$ ($/MW));~~

~~(n) the bid price of the Energy output from the reserved capacity ($EnBid_{ijt}$($/MWh)).~~

~~**Bid Evaluation**. Based on the quantity and location of the system requirements, the ISO shall select Generating Units, System Units, and System Resources with the bids, which minimize the sum of the total bids of the Generating Units, System Units, and System Resources selected for Regulation Up or Regulation Down, subject to two constraints:~~

~~(a) the sum of the selected bid capacities must be greater than or equal to the required Regulation capacity; and~~

~~(b) each Generating Unit's, System Unit's, or System Resource's bid capacity must be less than or equal to that Generating Unit's, System Unit's, or System Resource's ramp rate times $Period_{minutes}$.~~

~~The total bid for each Generating Unit, System Unit, or System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity.~~

~~Thus, subject to any locational requirements, the ISO will accept winning Regulation bids in accordance with the following criteria:~~

$$\cancel{Min \sum_{i,j} TotalBid_{ijt}}$$

~~Subject to~~

$$\cancel{\sum_{i,j} Cap_{ijt} \geq Requirement_t \text{ and } Cap_{ijt} \leq Cap_{ijtmax}}$$

~~Where~~

$\cancel{TotalBid_{ijt} = CapRes_{ijt} * Cap_{ijt}}$

~~$Requirement_t$ = Amount of upward and downward movement capacity required~~

<u>Price Determination</u>. ~~The price payable to Scheduling Coordinators for Regulation Capacity made available for upward and downward movement in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit, System Unit, and System Resource concerned, be the zonal market clearing price as follows:~~

$\cancel{PAGC_x = MCP_{xt}}$

~~Where:~~

~~The zonal market clearing (MCP_{xt}) price is the highest priced winning Regulation capacity bid in Zone X based on the capacity reservation bid price, i.e.~~

$\cancel{MCP_{xt} = Max\ (CapRes_{ijt}) \text{ in zone } x \text{ for Settlement Period } t}$

~~The ISO's auction does not compensate the Scheduling Coordinator for the minimum Energy output of Generating Units, System Units, or System Resources bidding to provide Regulation. Therefore, disposition of any minimum Energy associated with Regulation selected in the ISO's~~

~~Ancillary Services markets is the responsibility of the Scheduling Coordinator selling the Regulation.~~

~~The price payable to Scheduling Coordinators for Regulation capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21 shall be the bid price of the Regulation Capacity reserved ($CapRes_{ijt}$ ($/MW)).~~

2.5.15 [Not Used] ~~The Spinning Reserve Auction.~~

~~**Bid Information**. If the bid is for the provision of Spinning Reserve from a Generating Unit or System Unit, each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:~~

~~(a) bidder name/Identification Code;~~

~~(b) resource identification (name and Location Code);~~

~~(c) the date for which the bid applies;~~

~~(d) maximum operating level (MW);~~

~~(e) minimum operating level (MW);~~

~~(f) ramp rate (MW/min);~~

~~(g) MW additional capability synchronized to the system, immediately responsive to system frequency, and available within 10 minutes ($Cap_{ijt}max$) for Generating Unit i, or System Unit I, from Scheduling Coordinator j, for Settlement Period t.~~

~~(h) bid price of capacity reserved ($CapRes_{ijt}$ ($/MW));~~

~~(i) bid price of Energy output from reserved capacity ($EnBid_{ijt}$ ($/MWh)); and~~

~~(j) 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.~~

~~If the bid is for the provision of Spinning Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:~~

~~(a) bidder name/Identification Code;~~

~~(b) the date for which the bid applies;~~

~~(c) ramp rate if applicable (MW/Min);~~

~~(d) MW additional capability synchronized to the system, immediately responsive to system frequency and available at the point of interchange with the ISO Control Area, within 10 minutes ($Cap_{ijt}max$) of the ISO calling for the external import of System Resource i, from Scheduling Coordinator j, for Settlement Period t;~~

~~(e) bid price of capacity reserved ($CapRes_{ijt}$ ($/MW));~~

~~(f) bid price of Energy output from reserved capacity ($EnBid_{ijt}$ ($/MWh)); and~~

~~(g) 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~~

~~**<u>Bid Evaluation</u>**. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units and external imports of System Resources with the~~

~~bids which minimize the sum of the total bids of the Generating Units, System Units and external imports of System Resources selected subject to two constraints:~~

~~(a) the sum of the selected bid capacities must be greater than or equal to the required Spinning Reserve capacity; and~~

~~(b) each Generating Unit's, System Unit's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's or external import's ramp rate times 10 minutes.~~

~~The total bid for each Generating Unit, System Unit or external import of a System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity. Thus, subject to any locational requirements, the ISO will select the winning Spinning Reserve bids in accordance with the following criteria:~~

$\cancel{and\ Cap_{ijt} \leq Cap_{ijt} max}$

~~Where~~

$\cancel{TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}}$

$\cancel{Requirement_t}$ ~~= the amount of Spinning Reserve capacity required~~

~~Price Determination~~. ~~The price payable to Scheduling Coordinators for Spinning Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit or external import of a System Resource concerned be the zonal market clearing price for Spinning Reserve calculated as follows:~~

$\cancel{Psp_{xt} = MCP_{xt}}$

~~Where the zonal market clearing price (MCP_{xt}) for Spinning Reserve is the highest priced winning Spinning Reserve capacity bid in Zone X based on the capacity reservation bid price, i.e.:~~

~~$MCP_{xt} = Max(CapRes_{ijt})$ in zone x for Settlement Period t~~

~~The ISO's auction does not compensate a Scheduling Coordinator for the minimum Energy output of Generating Units, System Units or System resources bidding to provide Spinning Reserve. Therefore, any minimum Energy output associated with Spinning Reserve selected in the ISO's auction is the responsibility of the Scheduling Coordinator selling the Spinning Reserve.~~

~~The price payable to Scheduling Coordinators for Spinning Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21 shall be the bid price of the Spinning reserve capacity reserved ($CapRes_{ijt}$($/MW)).~~

2.5.16 [Not Used] ~~The Non-Spinning Reserve Auction.~~

~~**Bid information**. If the bid is for the provision of Non-Spinning Reserve from a Generating Unit or System Unit, each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:~~

~~(a) bidder name/Identification Code;~~

~~(b) Generating Unit or System Unit identification (name and Location Code);~~

~~(c) the date for which the bid applies;~~

~~(d) maximum operating level (MW);~~

~~(e) minimum operating level (MW);~~

~~(f) ramp rate (MW/Min);~~

~~(g) the MW capability available within 10 minutes ($Cap_{ijt}max$);~~

~~(h) the bid price of the capacity reserved ($CapRes_{ijt}$($/MW));~~

~~(i) time to synchronization following notification (min);~~

~~(j) the bid price of the Energy output from the reserved capacity ($EnBid_{ijt}$($/MWh)); and~~

~~(k) 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.~~

~~If the bid is for the provision of Non-Spinning Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:~~

~~(a) bidder name/Identification Code;~~

~~(b) the date for which the bid applies;~~

~~(c) ramp rate if applicable (MW/Min);~~

~~(d) the MW capability available at the point of interchange with the ISO Control Area, within 10 minutes ($Cap_{ijt}max$) of the ISO calling for the external import of System Resource I, from Scheduling Coordinator j, for Settlement Period t;~~

~~(e) the bid price of the capacity reserved ($CapRes_{ijt}$($/MW)); and~~

~~(f) the bid price of Energy output from reserved capacity ($EnBid_{ijt}$($/MWh)); and~~

~~(g) 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.~~

~~If the bid is for the provision of Non-Spinning Reserve from a Load located within the ISO Control Area, each Scheduling Coordinator j must submit the following information for each Load i for each Settlement Period t of the following Trading Day:~~

~~(a) bidder name/Identification Code;~~

~~(b) Load identification name and Location Code;~~

~~(c) the date for which the bid applies;~~

~~(d) Demand reduction available within 10 minutes (~~$Cap_{ijt}max$~~);~~

~~(e) to interruption following notification (min);~~

~~(f) maximum allowable curtailment duration (hr);~~

~~(g) the bid price of the capacity reserved (~~$CapRes_{ijt}$~~($/MW));~~

~~(h) the bid price for Demand reduction from the reserved capacity (~~$EnBid_{ijt}$~~($/MWh)); and~~

~~(i) an indication whether the capacity reserved would be available for Demand reduction only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency~~

~~**Bid Evaluation**. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Loads or external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units, Loads or external imports of System Resources selected subject to two constraints:~~

~~(a) the sum of the selected bid capacities must be greater than or equal to the required Non-Spinning Reserve capacity; and~~

~~(b) each Generating Unit's, System Unit's, Load's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's, Load's or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 10 minutes and the time to synchronize in the case of a Generating Unit or System Unit or to interruption in the case of a Load. The total bid for each Generating Unit, System Unit, Load or external import of a System Resource is calculated by multiplying the capacity reservation bid by the bid capacity.~~

~~Thus subject to any locational requirements, the ISO will accept the winning Non-Spinning Reserve bids in accordance with the following criteria:~~

~~Where~~

$\cancel{TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}}$

~~$Requirement_t$ = the amount of Non-Spinning Reserve capacity required~~

~~**Price Determination**. The price payable to Scheduling Coordinators for Non-Spinning Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall for each Generating Unit, System Unit, Load or external import of a System Resource concerned be the zonal market clearing price for Non-Spinning Reserve calculated as follows:~~

$\cancel{Pnonsp_{xt} = MCP_{xt}}$

~~Where the zonal market clearing price (MCP_{xt}) for Non-Spinning Reserve is the highest priced winning Non-Spinning Reserve bid in Zone X based on the capacity reservation bid price, i.e.:~~

~~$MCP_{xt} = Max(CapRes_{ijt})$ in zone x for Settlement Period t.~~

~~The price payable to Scheduling Coordinators for Non-Spinning Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21 shall be the bid price of the Non-Spinning Capacity reserved ($CapRes_{ijt}$($/MW)).~~

2.5.17 [Not Used] ~~The Replacement Reserve Auction.~~

~~**Bid Information**. If the bid is for the provision of Replacement Reserve from a Generating Unit or System Unit each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:~~

~~(a) bidder name/Identification Code;~~

~~(b) Generating Unit or System Unit identification (name and Location Code);~~

~~(c) the date for which the bid applies;~~

~~(d) maximum operating level (MW);~~

~~(e) minimum operating level (MW);~~

~~(f) ramp rate (MW/Min);~~

~~(g) the MW capacity available within 60 minutes ($Cap_{ijt}max$);~~

~~(h) the bid price of the capacity reserved ($CapRes_{ijt}$ ($/MW));~~

~~(i) time to synchronize following notification (min);~~

~~(j) the bid price of the Energy output from the reserved capacity ($EnBid_{ijt}$ ($/MWh)).~~

~~If the bid is for the provision of Replacement Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each~~

~~external import of a System Resource i for each Settlement Period t of the following Trading Day:~~

~~(a) bidder name/Identification Code;~~

~~(b) the date for which the bid applies;~~

~~(c) ramp rate applicable (MW/Min);~~

~~(d) the MW capability available at the point of interchange with the ISO Control Area, within 60 minutes ($Cap_{ijt}max$) of the ISO calling for the external import of System Resource i, from Scheduling Coordinator j, for Settlement Period t;~~

~~(e) bid price of capacity reserved ($CapRes_{ijt}$;($/MW)); and~~

~~(f) bid price of Energy output from reserved capacity ($EnBid_{ijt}$ ($/MWh)).~~

~~If the bid is for the provision of Replacement Reserve from a Load located within the ISO Control Area, each Scheduling Coordinator j must submit the following information for each Load i for each Settlement Period t of the following Trading Day:~~

~~(a) bidder name/Identification Code;~~

~~(b) Load identification (name and Location Code);~~

~~(c) the date for which the bid applies;~~

~~(d) the Demand reduction available within 60 minutes (Cap_{ijt} (MW));~~

~~(e) time to interruption following notification (min);~~

~~(f) maximum allowable curtailment duration (hr);~~

~~(g) the bid price of the capacity reserved ($CapRes_{ijt}$ ($/MW));~~

~~(h) the bid price of the Demand reduction from the reserved capacity ($EnBid_{ijt}$ ($/MWh)).~~

~~**Bid Evaluation**. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Loads or external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units, Loads or external imports of System Resources selected subject to two constraints:~~

~~(a) the sum of the selected bid capacities must be greater than or equal to the required Replacement Reserve capacity; and~~

~~(b) each Generating Unit's, System Unit's, Load's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's, Load's or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 60 minutes and the time to synchronize in the case of Generating Unit or System Unit, or to interruption in the case of Load.~~

~~The total bid for each Generating Unit, System Unit, Load or external import of System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity.~~

~~Thus, subject to any locational requirements, the ISO will select the winning Replacement Reserve bids in accordance with the following criteria:~~

~~Where~~

$\cancel{TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}}$

$\cancel{Requirement_t}$ ~~= the amount of Replacement Reserve capacity~~

~~**Price Determination.** The price payable to Scheduling Coordinators for Replacement Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit, System Unit, Load or external import of a System Resource, be the zonal market clearing price for Replacement Reserve calculated as follows:~~

~~$PRepRes_{xt} = MCP_{xt}$~~

~~Where the zonal market clearing price (MCP_{xt}) for Replacement Reserve is the highest priced winning Replacement Reserve bid in Zone X based on the capacity reservation bid price, i.e.:~~

~~$MCP_{xt} = Max(CapRes_{ijt})$ in zone x for Settlement Period t.~~

~~The price payable to Scheduling Coordinators for Replacement Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services schedules issued in accordance with section 2.5.21 shall be the bid price of the Replacement Reserve capacity reserved ($CapRes_{ijt}(\$/MW)$).~~

2.5.18 Voltage Support.

As of the ISO Operations Date, the ISO will contract for Voltage Support service with the owners of Reliability Must-Run Units. Payments for public utilities under the FPA shall be capped at the FERC authorized cost based rates unless and until FERC authorizes different pricing. The ISO shall pay owners of Reliability Must-Run units for long term Voltage Support through their Scheduling Coordinators.

In addition, any Participating Generator's **Generating Unit or Capacity~~ACAP~~ R~~r~~esource that** ~~who~~ is producing Energy shall, upon the ISO's specific request, provide reactive energy output outside the Participating Generator's Voltage Support obligation defined in Section 2.5.3.4.

The ISO shall select Participating Generator's Generating Units which have been certified for Voltage Support to provide this additional Voltage Support. Subject to any locational requirements, the ISO shall select the least costly Generating Units from a computerized merit order stack to back down to produce additional Voltage Support in each location where Voltage Support is needed.

The ISO shall pay to the Scheduling Coordinator for that Participating Generator the opportunity cost of reducing Energy output to enable reactive energy production. This opportunity cost shall be:

Max{0, Zonal ~~BEEP Interval~~**Dispatch Interval** ~~Ex Post Price~~**Locational Marginal Price**- Generating Unit bid price } x reduction in Energy output (MW).

If necessary, the ISO shall develop a regulatory cost based determination of marginal operating cost to be used in place of the Generating Unit bid price.

2.5.19 Black Start Capability and Energy Output.

As of the ISO Operations Date, the ISO will contract for Black Start capability and Energy with owners of Reliability Must-Run Units and Black Start Generators. Public utilities under the FPA will be paid rates capped at the FERC authorized cost base rates unless and until FERC authorizes different pricing. The ISO shall pay owners of Reliability Must-Run Units for Black Start Energy output through their Scheduling Coordinators. The ISO shall pay Black Start Generators for Black Start Energy output directly.

2.5.20 Obligations for and Self Provision of Ancillary Services.

2.5.20.1 Ancillary Service Obligations. Each Scheduling Coordinator shall be assigned a share of the total Regulation, Spinning Reserve **and**~~,~~ Non-Spinning~~ and Replacement~~ Reserve requirements by the ISO. Any references in this Tariff to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up or ~~"~~Regulation Down". The share assigned to each Scheduling Coordinator is described in Section 2.5.20 and in Section 2.5.28 as that Scheduling Coordinator's obligation. Each Scheduling Coordinator's Regulation obligation in each **Ancillary**

__Services Region__~~Zone~~ shall be pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (excluding exports) bears to the total metered Demand (excluding exports) served in each hour in that **__Ancillary Services Region__**~~Zone~~. Each Scheduling Coordinator’s Operating Reserve obligation in each **__Ancillary Services Region__**~~Zone~~ shall be pro rata based upon the same proportion as the ratio of the product of its percentage obligation based on metered output and the sum of its metered Demand and firm exports bears to the total of such products for all Scheduling Coordinators in the **__Ancillary Services Region__**~~Zone~~. The Scheduling Coordinator’s percentage obligation based on metered output shall be calculated as the sum of 5% of its real time Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from hydroelectric resources plus 7% of its Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from non-hydroelectric resources in that **__Ancillary Services Region__**~~Zone~~, plus 100% of any Interruptible Imports and on-demand obligations which it schedules. ~~Each Scheduling Coordinator’s Replacement Reserve obligation in each Zone is calculated as described in Section 2.5.28.4.~~ Scheduling Coordinator obligations for each Ancillary Service will be calculated based on the requirement for each Ancillary Service as the ISO determines prior to the adjustment set forth in Section 2.5.3.6.

2.5.20.2 Right to Self Provide.

Each Scheduling Coordinator may choose to self provide all, or a portion, of its Regulation and~~,~~ Operating Reserve~~, and Replacement Reserve~~ obligation in each **__Ancillary Services Region__**~~Zone~~. The ISO shall schedule self provided Ancillary Services, Day-Ahead and Hour-Ahead, and Dispatch self provided Ancillary Services in real time. To the extent that a Scheduling Coordinator self provides, the ISO shall correspondingly reduce the quantity of the Ancillary Services concerned, which it procures as described in Sections **__31.2.3.1.3__** ~~2.5.14 to~~

~~2.5.17~~. In accordance with Section 2.5.22.11 and Section 2.5.26.2, if a Scheduling Coordinator uses capacity scheduled to self-provide Spinning Reserve**,** or~~,~~ Non-Spinning Reserve~~, or Replacement Reserve~~ to supply Uninstructed Imbalance Energy to the ISO from a Generating Unit, ~~Curtailable Demand~~ **Dispatchable Load**, or System Resource under circumstances that would cause the elimination of payments to the Scheduling Coordinator under Section 2.5.26.2 if the capacity had been bid and was selected by the ISO to supply the Ancillary Service, the Scheduling Coordinator shall pay to the ISO the amount of the payment that would be eliminated under that section. Scheduling Coordinators may trade Ancillary Services obligations so that any Scheduling Coordinator may reduce its Ancillary Services obligation through purchase of Ancillary Services capacity from another Scheduling Coordinator, or self-provide in excess of its obligation to sell Ancillary Services to another Scheduling Coordinator, subject to the limits specified under Section 2.5.20.5.2. If a Scheduling Coordinator's Day-Ahead self-provided Ancillary Service schedule is decreased in the Hour-Ahead Market, such decrease shall be deemed to be replaced ~~at the Market Clearing Price in the Hour-Ahead Market,~~ pursuant to Section **31.3.4** ~~2.5.21~~.

2.5.20.3 [Not Used]

2.5.20.4 Services Which May Be Self Provided. The ISO shall permit Scheduling Coordinators to self provide the following Ancillary Services:

(a) Regulation;

(b) Spinning Reserve; **and**

(c) Non-Spinning Reserve.~~; and~~

(d) ~~Replacement Reserve.~~

The ISO may from time to time add other Ancillary Services to this list as it considers appropriate.

* * *

2.5.21 Scheduling of Units to Provide Ancillary Services.

The ISO shall prepare supplier schedules for Ancillary Services (both self provided and purchased by the ISO) for the Day-Ahead and the Hour-Ahead Markets. The ISO shall notify each Scheduling Coordinator no later than 1:00 p.m. of the day prior to the Trading Day of their Ancillary Services schedules for the Day-Ahead and no later than **forty-five (45) minutes** ~~one hour~~ prior to the operating hour of their Ancillary Services schedules for the Hour-Ahead. The ISO Protocols set forth the information, which will be included in these schedules. Where long-term contracts are involved, the information may be treated as standing information for the duration of the contract.

If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day and before the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day, the ISO determines that it requires Ancillary Services in addition to those included in the Final Day-Ahead Schedule (in the appropriate **Ancillary Services Region**~~zone~~ if procuring zonally), the ISO may procure such additional Ancillary Services by providing Scheduling Coordinators with amended supplier schedules for the Day-Ahead Markets that include Ancillary Services for which previously submitted (but not selected) bids remain available and have not previously been withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant **Ancillary Services Region**~~zone if the ISO is procuring Ancillary Services on a zonal basis~~). Such amended supplier schedules shall be provided to the Scheduling

Coordinators no later than the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day.

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above. ~~Any minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units bidding to provide these services. Accordingly the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units included on the Schedules.~~

~~Notwithstanding the foregoing, a Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace that capacity in whole or in part from the ISO if the scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or if the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Units or other resources are located. The ISO will purchase the Ancillary Service concerned from another Scheduling Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.~~

2.5.22 Rules For Real Time Dispatch of Imbalance Energy Resources.

2.5.22.1 Overview. During real time, the ISO shall dispatch Generating Units, Loads and System Resources **in accordance with Section 31.4.3** 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.

2.5.22.2 **[Not Used]** ~~**General Principles.** The ISO shall base real time dispatch of Generating Units, System Units, Loads and System Resources on the following principles:~~

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

~~(b) once ACE has returned to zero, the ISO shall determine whether the Regulation Generating Units, System Units, and System Resources are operating at a point away from their preferred operating point. The ISO shall then adjust the output of Generating Units, System Units, and System Resources available (either providing Spinning Reserve, Non-Spinning Reserve, Replacement Reserve or offering Supplemental Energy) to return the Regulation Generating Units, System Units, 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 and System Resources only to meet its Imbalance Energy requirements and eliminate any Price Overlap between incremental and decremental energy bids;~~

~~(d) subject to Section 2.5.22.3 and its subparts, the ISO shall select the Generating Units, System Units, Loads and System Resources to be dispatched to meet its Imbalance Energy requirements and eliminate any Price Overlap based on a merit order of Energy bid prices;~~

~~(e) subject to Section 2.5.22.3 and its subparts, the ISO shall not discriminate between Generating Units, System Units, Loads 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;~~

~~(f) Generating Units, System Units, Loads 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 BEEP IntervalDispatch Interval.~~

2.5.22.3 Ancillary Services Dispatch. 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, **and** (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 WSCC guidelines.

2.5.22.3.1 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 bid prices as described in their Ancillary Service schedule and their effectiveness, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3.

2.5.22.3.2 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 position of the Generating Unit, Load, System Unit or

System Resource in the merit order for real time Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3.

2.5.22.4 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 **to the Hour-Ahead Energy Market**.

2.5.22.4.1 [Not Used]~~Timing of Supplemental Energy Bids.~~

~~Supplemental Energy bids must be submitted to the ISO no later than forty-five (45) 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 forty-five (45) minutes prior to the Settlement Period, except that a bid from a System Resource may specify that any portion of the bid that is not called prior to the beginning of the Settlement Period shall not be called after the beginning of the Settlement Period. The ISO may dispatch the associated resource at any time during the Settlement Period.~~

2.5.22.4.2 [Not Used] ~~Form of Supplemental Energy Bid Information.~~

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

~~(a) Bidder name and identification;~~

~~(b) Resource name, identification, and location;~~

~~(c) the positive or negative bid price of incremental and decremental changes in Energy (up to eleven ordered pairs of quantity/price representing up to ten steps);~~

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

~~(e) Generating Unit ramp rate (MW/Min); and~~

~~(f) Such other information as the ISO may determine it requires to evaluate bids, as published from time to time in ISO Protocols.~~

2.5.22.5 [Not Used.] ~~**Information used in the Real Time Dispatch.** The ISO shall place all the bid price information (except for Regulation bid prices and Adjustment Bids carried forward from the Day-Ahead and Hour-Ahead Markets) received from available Generating Units, Loads, System Units and System Resources in a database for use in real time Dispatch of Balancing Energy. The database shall indicate:~~

~~(a) Generating Unit/Load/ System Unit/ System Resource name;~~

~~(b) congestion zone;~~

~~(c) quantity bid;~~

~~(d) normal ramp rate;~~

~~(e) price;~~

~~(f) whether the Generating Unit/ Load/ System Unit/ System Resource has been contracted to provide any Ancillary Services and/or Supplemental Energy, and, if so, which ones.~~

~~The quantity blocks shall be ordered in a merit order stack of ascending incremental and descending decremental price bids. Energy bids associated with Spinning and Non-Spinning Reserve shall be included in the merit order stack during normal operating conditions unless 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.~~

2.5.22.6 **[Not Used]** ~~**Real Time Dispatch.** The ISO shall economically dispatch Generating Unit, Load, System Unit or System Resource that is effective to 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 2.5.22.3. The ISO shall determine that additional output is needed if the current output levels of the Regulation Generating Units, System Units, and System Resources exceed their preferred operating points by more than a specified threshold (to be determined by the ISO). The ISO shall determine that less output is needed if the output levels of the Regulation Generating Units, System Units, and System Resources fall below their preferred operating points by more than a specified threshold (to be determined by the ISO). To minimize the cost of providing Imbalance Energy, the ISO shall economically increase or reduce Demand or Energy output from Generating Units, Loads, System Units or System Resources according to Energy Bid prices.~~

~~Once a bid has been accepted by the ISO, the database shall be adjusted to reflect the change in status of the bid. Once a decremental bid has been used by the ISO, it will then be included in the incremental part of the database with an incremental bid equal to its decremental price bid. Once an incremental bid has been used by the ISO it will then be included in the decremental part of the database with a decremental bid equal to its incremental price bid.~~

2.5.22.7 **[Not Used]**~~**Inter-Zonal Congestion.** In the event of Inter-Zonal Congestion in real time, the ISO shall procure Imbalance Energy separately for each Zone, as described in Section 2.5.22.6.~~

2.5.22.8 **[Not Used]** ~~**Intra-Zonal Congestion.** Except as provided in Section 5.2, in the event of Intra-Zonal Congestion in real time, the ISO shall adjust resources in accordance with Section 7.2.6.2.~~

2.5.22.9 [Not Used] ~~Replacement of Operating Reserve.~~ ~~If pre-arranged Operating Reserve is used to meet Imbalance Energy requirements, such Operating Reserve may be replaced by the ISO's dispatch of additional Imbalance Energy through available Supplemental Energy Bids.~~

~~Any additional Operating Reserve needs may also be met in the same way. Where the ISO elects to rely upon Supplemental Energy Bids, the ISO shall select the resources with the lowest incremental Energy price bids. Operating Reserve procured from Replacement Reserve shall not require replacement of utilized Replacement Reserve.~~

2.5.22.10 Dispatch Instructions.

~~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. 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 recipient of a Dispatch instruction shall confirm the Dispatch. 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.~~

The ISO Protocols govern the content, issue, receipt, confirmation and recording of Dispatch instructions.

2.5.22.11 Failure to Conform to Dispatch Instructions. All Scheduling Coordinators, Participating Generators, owners or operators of ~~Curtailable Demand~~**Dispatchable Loads** 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~~**Dispatchable Load** 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~~**Dispatchable Load** or System Resource: 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,~~;~~

cannot set the **Dispatch Interval Locational Marginal Price**~~BEEP Interval Ex Post Price;~~ and

the Scheduling Coordinator for the Participating Generator, owner or operator of the ~~Curtailable Demand~~**Dispatchable Load** or System Resource concerned shall have Uninstructed Imbalance Energy due to the difference between the Generating Unit's, ~~Curtailable Demand~~**Dispatchable Load'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, ~~Curtailable Demand~~**Dispatchable Load** and System Resources from failing to perform according to Dispatch instructions, for example reduction in payments to Scheduling Coordinators, or suspension of the Scheduling Coordinator's Ancillary Services certificate for the Generating Unit, ~~Curtailable Demand~~**Dispatchable Load** or System Resource concerned.

2.5.23 Pricing Imbalance Energy.

2.5.23.1 General Principles. ~~Instructed and Uninstructed Imbalance Energy shall be priced using the BEEP Interval Ex Post Prices. The BEEP Interval Ex Post Prices shall be based on the bid of the marginal Generating Units, System Units, Loads or System Resources dispatched by the ISO to increase or reduce Demand or Energy output in each BEEP Interval as provided in Section 2.5.23.2.1.~~

~~The marginal bid is the highest bid that is accepted by the ISO's BEEP Software for increased energy supply or the lowest bid that is accepted by the ISO's BEEP 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 BEEP 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 **I**~~i~~nstructions issued by **SCED**~~the BEEP 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 **I**~~i~~nstructions issued by **SCED**~~the BEEP Software~~.

2.5.23.2 [Not Used] ~~Determining Ex Post Prices.~~

2.5.23.2.1 [Not Used] ~~BEEP Interval Ex Post Prices~~. ~~For each BEEP Interval, the ISO will compute updated supply and demand curves, using the Generating Units, System Units, Loads and System Resources dispatched according to the ISO's BEEP Software during that time period to meet Imbalance Energy requirements and to eliminate any Price Overlap. The BEEP 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 2.5.23.3. For each BEEP Interval of the Settlement Period, BEEP will compute the Ex Post Price so that is:~~

~~(a) greater than or equal to the prices of accepted incremental bids;~~

~~(b) smaller than or equal to the prices of unaccepted incremental bids;~~

~~c) smaller than or equal to the prices of accepted decremental bids; and~~

~~(d) greater than or equal to prices of unaccepted decremental bids.~~

~~In the event of Inter-Zonal Congestion, the ISO will develop supply and demand curves separately for each Zone separated by congestion.~~

2.5.23.2.2 **[Not Used]** ~~**Hourly Ex Post Price.** The Hourly Ex Post Price in Settlement Period t in each Zone will equal the Energy weighted average of the BEEP Interval Prices in each Zone, calculated as follows:~~

$$HP_{xt} = \frac{\sum_b |Q_{bxt}| P_{bxt}}{\sum_b |Q_{bxt}|}$$

~~Where:~~

~~HP_{xt} is the Hourly Ex Post Price in Zone x;~~

~~P_{bxt} is the BEEP Interval Ex Post Price during BEEP Interval b in Zone x; and~~

~~Q_{bxt} is the total the Instructed Imbalance Energy during BEEP Interval b in Zone x.~~

~~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.~~

2.5.23.3 **[Not Used]** ~~**Temporary Limitation on BEEP Interval Ex Post Prices**~~

2.5.23.3.1 **[Not Used]** ~~**Limitation.** Notwithstanding any other provision of the ISO Tariff, the BEEP Interval Ex Post Price shall not exceed $150. Scheduling Coordinators for Generating Units, System Units, and System Resources that submit bids above $150 for the supply of Imbalance Energy shall be paid in accordance with their bids if accepted for Dispatch by the ISO.~~

2.5.23.3.2 **[Not Used]** ~~**Charges for Certain Instructed Imbalance Energy.** Amounts paid to Scheduling Coordinators in accordance with Section 2.5.23.3.1 for Instructed Imbalance Energy from Generating Units, System Units and System Resources at bids above $150 shall be charged to Scheduling Coordinators such that the charge to each Scheduling Coordinator~~

~~shall be pro rata based upon the same proportion as the Scheduling Coordinator's Net Negative Uninstructed Deviations for the BEEP Interval bears to the total Net Negative Uninstructed Deviations of all Scheduling Coordinators for the BEEP Interval. Such charge shall apply in lieu of any charge specified in the ISO Tariff for such Instructed Imbalance Energy based on the BEEP Interval Ex Post Price.~~

2.5.23.3.3 [Not Used]

* * *

2.5.25.4 <u>**[Not Used]**</u> ~~**Replacement Reserve.** The ISO may test the Replacement Reserve capability of a Generating Unit, Load, System Unit or System Resource by issuing unannounced Dispatch instructions requiring the Generating Unit, Load, System Unit or System Resource to come on line and ramp up or reduce Demand to its sixty minute capability. The ISO shall measure the response of the Generating Unit, Load, System Unit or System Resource to determine compliance with requirements. The Scheduling Coordinator for the Generating Unit, Load, System Unit or System Resource shall be paid the Energy or Demand reduction Bid price of the Generating Unit, Load, System Unit or System Resource for the output, or reduction, of the Generating Unit, Load, System Unit or System Resource under the Replacement Reserve test.~~

2.5.25.5 Voltage Support. The ISO shall monitor a Generating Unit's response to Voltage Support instructions in order to determine compliance with Dispatch <u>I</u>~~i~~nstructions.

2.5.25.6 Black Start. The ISO may test the Black Start capability of a Generating Unit by issuing unannounced <u>D</u>~~d~~ispatch <u>I</u>~~i~~nstructions requiring the Generating Unit to start on a Black Start basis. The ISO shall measure the response of the Generating Unit to determine compliance with the terms of the Black Start contract. The Scheduling Coordinator or Black

Start Generator ~~as stated in Section 2.5.27.6~~ for the Generating Unit shall be paid the Generating Unit's contract price for the output under the Black Start test **as set forth in Settlements and Billing Protocol Appendix G**.

2.5.26 Penalties for Failure to Pass Tests and Rescission of Payment for Non-Delivery.

2.5.26.1 Penalties for Failure to Pass Tests. A Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource that fails an availability test, as determined under criteria to be established by the ISO, shall be deemed not to have been available to provide the Ancillary Service concerned or the relevant portion of that Service for the entire period the Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource was committed to provide the Service, unless appropriate documentation (i.e., daily test records) confirming the availability of that service during the committed period(s) is presented to the ISO. The "committed period" **for the purpose of rescinding payments for non-delivery** is defined as the total of all the hours/days the Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource was scheduled by the ISO to provide the Ancillary Service beginning from: (i) the last successful availability test; or (ii) the last time the Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource actually provided Energy or reduced Demand as part of the Ancillary Service; whichever results in a shorter committed period. The Scheduling Coordinator for a Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource that fails an availability test shall not be entitled to payment for the Ancillary Service concerned for the committed period and adjustments to reflect this shall be made in the calculation of payments to the Scheduling Coordinator, provided that any such penalty shall be reduced to reflect any adjustment made over the duration of the committed period under Section 2.5.26.2 or 2.5.26.3.

System Units engaged in self provision of Ancillary Services, or providing Ancillary Services to the ISO are subject to the same testing, compensation, and penalties as are applied to individual Generating Units engaged in self provision or provision of Ancillary Services. To perform testing, the ISO will bias the MSS's MSRE to test the responsiveness of the System Unit.

If payments for capacity for a particular Ancillary Service in a particular Settlement Period would be rescinded under more than one provision of this Section 2.5.26, the total amount to be rescinded for a particular Ancillary Service in a particular Settlement Period shall not exceed the total payment due in that Settlement Period.

2.5.26.2 Rescission of Payments for Unavailability. If capacity scheduled into the ISO's Ancillary Services markets from a Generating Unit, ~~Curtailable Demand~~**Dispatchable Load, System** Unit or System Resource is unavailable during the relevant ~~BEEP Interval~~**Dispatch Interval**, then payments will be rescinded as described herein. For self-provided Ancillary Services, the payment obligation shall be equivalent to that which would arise if the Ancillary Services had been bid into each market in which they were scheduled.

2.5.26.2.1 If the ISO determines that a Scheduling Coordinator has supplied Uninstructed Imbalance Energy to the ISO during a ~~BEEP Interval~~**Dispatch Interval** from the capacity of a Generating Unit, System Unit or System Resource that is obligated to supply Spinning Reserve **or**~~,~~ Non-Spinning Reserve~~, or Replacement Reserve~~ to the ISO during such ~~BEEP Interval~~**Dispatch Interval**, payments to the Scheduling Coordinator representing the Generating Unit, System Unit or System Resource for the Ancillary Service capacity used to supply Uninstructed Imbalance Energy shall be eliminated to the extent of the deficiency, except to the extent (i) the deficiency in the availability of Ancillary Service capacity from the Generating Unit, System Unit or System Resource is attributable to control exercised by the ISO in that ~~BEEP~~

~~Interval~~**Dispatch Interval** through AGC operation, an RMR Dispatch Notice, or dispatch to avoid an intervention in Market operations or to prevent a System Emergency; or (ii) a penalty is imposed under Section 2.5.26.1 with respect to the deficiency.

2.5.26.2.2 If the metered Demand of a ~~Curtailable Demand~~**Dispatchable Load** is insufficient to deliver the full amount of the Non-Spinning ~~and Replacement~~ Reserve to which that ~~Curtailable Demand~~**Dispatchable Load** is obligated in that ~~BEEP Interval~~**Dispatch Interval**, then the related capacity payments will be rescinded to the extent of that deficiency as explained in Section 2.5.26.2.4 and 2.5.26.2.5, unless a penalty is imposed on that ~~Curtailable Demand~~**Dispatchable Load** for that ~~BEEP Interval~~**Dispatch Interval** under Section 2.5.26.1.

2.5.26.2.3 **[Not Used]**

2.5.26.2.4 This Section 2.5.26.2.4 shall not apply to the capacity payment for any particular Ancillary Service if the **relevant Ancillary Services Marginal Price** ~~Zonal Market Clearing Price~~ determined in accordance with Sections **31.2.3.1.4.3** ~~2.5.15, 2.5.16 or 2.5.17~~ is less than or equal to zero. For those Ancillary Services for which **such relevant Ancillary Services Marginal Prices** ~~Zonal Market Clearing Prices~~ are greater than zero, the payment for Ancillary Service capacity otherwise payable under Section **31.2.3.4.2.1 or 31.2.3.4.2.2** ~~2.5.27.2, 2.5.27.3, and/or 2.5.27.4~~ shall be reduced by one sixth of the product of the applicable prices and the amount of Ancillary Service capacity from which the Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource has supplied Uninstructed Imbalance Energy in a ~~BEEP Interval~~**Dispatch Interval**. If a Scheduling Coordinator schedules Ancillary Services through both the Day-Ahead and Hour-Ahead Markets, capacity payments due the Scheduling Coordinator from each market will be rescinded in proportion to the amount of capacity sold to the ISO in each market. The amount of capacity for which payments will be rescinded shall equal the value $UnavailAncServMW_{ixt}$, as defined in Section 11.2.4.1, applied to each Generating Unit, System Unit and System Resource supplying the Ancillary Service or the value $UnavailDispLoadMW_{ixt}$, as also defined in Section 11.2.4.1, applied to the ~~Curtailable Demand~~**Dispatchable Load** supplying the Ancillary Service.

2.5.26.2.5 Payment shall be eliminated first for any Spinning Reserve capacity for which the Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource would otherwise be entitled to payment. If the amount of Ancillary Service capacity from which the Generating Unit, System Unit or System Resource has supplied Uninstructed Imbalance Energy exceeds the amount of Spinning Reserve capacity for which it would otherwise be entitled to receive payment, payment shall be eliminated for Non-Spinning Reserve capacity, ~~and then for Replacement Reserve capacity,~~ until payment has been withheld for the full amount of Ancillary Service capacity from which the Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource supplied Uninstructed Imbalance Energy.

2.5.26.2.6 For each ~~BEEP Interval~~**Dispatch Interval** in which a Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource fails to actually supply Energy from Spinning Reserve, **or** Non-Spinning Reserve~~ or Replacement Reserve~~ capacity in accordance with a Dispatch **I**~~i~~nstruction, or supplies only a portion of the Energy specified in the Dispatch Instruction, the capacity payment will be pro-rated to reflect the unavailability in that ~~BEEP Interval~~**Dispatch Interval** of the difference between (1) the total MW of the particular Ancillary Service scheduled in that Settlement Period and (2) the amount of Energy, if any, supplied in response to the Dispatch **I**~~i~~nstruction in that ~~BEEP Interval~~**Dispatch Interval**.

2.5.26.3 Rescission of Payments When Dispatch Instruction is Not Followed

If the total metered output of a Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource is insufficient to supply the amount of Instructed Imbalance Energy associated with a Dispatch **I**~~i~~nstruction issued in accordance with a bid on Spinning Reserve **or**, Non-Spinning Reserve~~, or Replacement Reserve~~ in any ~~BEEP Interval~~**Dispatch Interval**, then the capacity payment associated with the difference between the total scheduled amount of each Ancillary Service for which Insufficient Energy was delivered, and the actual output attributed to the response to the Dispatch **I**~~i~~nstruction on each Ancillary Service, shall be rescinded. However, no capacity payment shall be rescinded if the shortfall in the metered output of the Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit, or System Resource is less than a deadband amount published by ISO on the ISO Home Page at least twenty-four hours prior to the ~~BEEP Interval~~**Dispatch Interval**. For any ~~BEEP Interval~~**Dispatch Interval** with respect to which no deadband amount has been published by the ISO, the deadband amount shall be zero MWH. If the Generating Unit, ~~Curtailable Demand~~**Dispatchable Load**, System Unit or System Resource is scheduled to provide more than one Ancillary Service in the Settlement Period, then the actual output will be attributed first to ~~Replacement Reserve, then to~~ Non-Spinning Reserve~~,~~ and finally to Spinning Reserve, and the capacity payments associated with the balance of each Ancillary Service shall be rescinded. If the same Ancillary Service is scheduled in both the Day Ahead and Hour Ahead Markets, then payments shall be rescinded in proportion to the amount of each Ancillary Service scheduled in each market.

2.5.26.4 Penalties applied pursuant to Section 2.5.26.1, and payments rescinded pursuant to Section 2.5.26.2 and 2.5.26.3 shall be redistributed to Scheduling Coordinators in proportion to ISO Control Area metered Demand for the same Trading Day.

2.5.26.5 If the ISO determines that non-compliance of a Load, Generating Unit, System Unit or System Resource, with an operating order or Dispatch **I**~~i~~nstruction from the ISO, or with any other applicable technical standard under the ISO Tariff, causes or exacerbates system conditions for which the WSCC imposes a penalty on the ISO, then the Scheduling Coordinator of such Load, Generating Unit, System Unit or System Resource shall be assigned that portion of the WSCC penalty which the ISO reasonably determines is attributable to such non-compliance, in addition to any other penalties or sanctions applicable under the ISO Tariff.

2.5.26.6 Temporary Exemption from Rescission of Energy Payments Any Participating Load that has entered into a Participating Load Agreement and has responded to a Dispatch **I**~~i~~nstruction ~~will be exempt from the requirements of Section~~ **shall be exempt from Uninstructed Deviation Penalties in Section 11.2.4.1.2 (d)** ~~2.5.26.2.3~~ in the hour of the Dispatch and for the following two (2) hours during the period beginning on June 15, 2000 and ending on the date specified in a notice ("Notice Terminating Temporary Exemption") to be issued by the ISO. Such notice shall be posted on the ISO Home Page and distributed to Market Participants via e-mail at least seven (7) calendar days in advance of the termination of this temporary exemption.

2.5.27 [Not Used] ~~**Settlements For Contracted Ancillary Services.**~~

~~Based on the prices and quantities determined in accordance with this Section, the ISO shall operate a daily Settlement function for Ancillary Services it contracts for with Scheduling Coordinators.~~

~~The ISO shall calculate imbalances between scheduled, instructed and actual quantities of Energy provided based upon Meter Data obtained pursuant to Section 10. Schedules between Control Areas shall be deemed as being delivered in accordance with Good~~

~~Utility Practice. The difference between actual and scheduled interchange shall then be addressed in accordance with the WSCC and NERC inadvertent interchange practices and procedures. Following this practice, all dynamic schedules for Ancillary Services provided to the ISO by other Control Areas shall be deemed delivered to the ISO. The difference between the Energy requested by the ISO and that actually delivered by the other Control Area shall then be accounted for and addressed through the WSCC and NERC inadvertent interchange practices and procedures.~~

~~Separate payments shall be calculated for each Settlement Period t for each Generating Unit, System Unit, System Resource and Curtailable Demand. The ISO shall then calculate a total daily payment for each Scheduling Coordinator for all the Generating Units, System Units, System Resources and Curtailable Demands that it represents for each Settlement Period t.~~

~~The settlements for the Hour-Ahead markets shall be calculated by substituting Hour-Ahead prices in the relevant formulae and deducting any amounts due to the ISO from Scheduling Coordinators who buy back in the Hour-Ahead Market Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity they sold to the ISO in the Day-Ahead Market.~~

2.5.27.1 [Not Used] ~~Regulation.~~

~~Regulation Up and Regulation Down payments shall be calculated separately.~~

~~**Quantities**. The following quantity definitions shall be used for each Scheduling Coordinator in the settlement process:~~

~~$AGCUpQDA_{xt}$ = the Scheduling Coordinator's total quantity of Regulation Up capacity in Zone X sold through the ISO auction at bids at or below the level specified in Section 2.5.27.7, and scheduled Day-Ahead j for Settlement Period t.~~

~~$AGCDownQDA_{xt}$ = the Scheduling Coordinator's total quantity of Regulation Down capacity in Zone X sold through the ISO auction at bids at or below the level specified in Section 2.5.27.7, and scheduled Day-Ahead j for Settlement Period t.~~

~~$EnQInst_{xt}$ = Instructed Imbalance Energy increase or decrease in Zone X in real time Dispatch for each~~ BEEP Interval ~~b of Settlement Period t, determined in accordance with the ISO Protocols.~~

~~**Prices.** The prices in the Settlement process for Regulation Up and Regulation Down shall be those determined in Section 2.5.14 for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level.~~

~~*Adjustment*: penalty described in Section 2.5.26.1.~~

~~$PAGCUpDA_{xt}$ = the market clearing price, PAGC, in Zone X for Regulation Up capacity in the Day-Ahead market for Settlement Period t.~~

~~$PAGCDownDA_{xt}$ = the market clearing price, PAGC, in Zone X for Regulation Down capacity in the Day-Ahead market for Settlement Period t.~~

~~**Payments.** Scheduling Coordinators for Generating Units providing Regulation Up capacity through the ISO auction shall receive the following payments for Regulation Up:~~

$$\cancel{AGCUpPay_{xt} = AGCUpQDA_{xt} * PAGCUpDA_{xt} - Adjustment}$$

~~Scheduling Coordinators for Generating Units providing Regulation Down capacity through the ISO auction shall receive the following payments for Regulation Down:~~

$$\cancel{AGCDownPay_{xt} = AGCDownQDA_{xt} * PAGCDownDA_{xt} - Adjustment}$$

~~Scheduling Coordinators for Generating Units shall receive the following payment for Energy output from Regulation in accordance with the settlement for Instructed Imbalance Energy under Section 11.2.4.1:~~

$$\sum_i [(EnQInst_{ixt} * BEEPIntervalExPostPriceinZoneX) + REPAi_{xt}]$$

~~$REPA_{ixt}$ = the Regulation Energy Payment Adjustment for Generating Unit i in Zone X for Settlement Period t calculated as follows:~~

~~$[(R_{UPixt} * C_{UP}) + (R_{DNixt} * C_{DN})] * \max(\$20/MWh, P_{xt})$~~

~~Where~~

~~R_{UPixt} = the upward range of generating capacity for the provision of Regulation from Generating Unit i in Zone X included in the bid accepted by the ISO for Generating Unit i for Settlement Period t, weighted in proportion to the ISO's need for upward Regulation. The weighting factors will be specified within a range from 0-100 percent. The weighting factors will be set at the discretion of the ISO based on system conditions, and will be set at a level that will provide sufficient incentive to the market to supply upward Regulation for the ISO's purposes of satisfying WSCC criteria and NERC control performance standards. The ISO shall post the weighting factors consistent with the ISO Weighting Procedure, posted on the ISO website.~~

~~R_{DNixt} = the downward range of generating capacity for the provision of Regulation for Generating Unit i in Zone X included in the bid accepted by the ISO for Generating Unit i for Settlement Period t, weighted in proportion to the ISO's need for downward Regulation. The weighting factors will be specified within a range from 0-100 percent. The weighting factors will be set at the discretion of the ISO based on~~

~~system conditions, and will be set at a level that will provide sufficient incentive to the market to supply downward Regulation for the ISO's purposes of satisfying WSCC criteria and NERC control performance standards. The ISO shall post the weighting factors consistent with the ISO Weighting Procedure, posted on the ISO website.~~

~~C_{UP} = 0 to 1~~

~~C_{DN} = 0 to 1~~

~~P_{xt} = the Hourly Ex Post Price for Zone X in Settlement Period t.~~

~~The ISO may modify the value of the constants C_{UP} or C_{DN} within a range of 0-1 either generally in regard to all hours or specifically in regard to particular times of the day, after the ISO Governing Board approves such modification, by a notice issued by the Chief Executive Officer of the ISO and posted on the ISO Internet "Home Page," at http//www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date and time from which the modification shall take effect, which shall be not less than seven (7) days after the Notice is issued.~~

~~REPA shall not be payable unless the Generating Unit is available and capable of being controlled and monitored by the ISO Energy Management System over the full range of its Scheduled Regulation capacity for the entire Settlement Period at least the ramp rates (increase and decrease in MW/minute) stated in its bid. In addition, the total Energy available (R_{UP} plus R_{DN}) may be adjusted to be only R_{UP} or only R_{DN}, a percentage of R_{UP} or R_{DN}, or the sum of R_{UP} and R_{DN}, depending on the needs of the ISO for each direction of Regulation service.~~

2.5.27.2 [Not Used] ~~Spinning Reserve.~~

~~**<u>Quantities</u>**. The following quantity definitions shall be used for each Scheduling Coordinator in the Settlement process:~~

~~$SpinQDA_{xt}$ = the Scheduling Coordinator's total quantity of Spinning Reserve capacity in Zone X sold through the ISO auction at bids at or below the level specified in Section 2.5.27.7, and scheduled Day-Ahead for Settlement Period t.~~

~~$EnQInst_{xt}$ = Instructed Imbalance Energy output in Zone X in real time Dispatch for Settlement Period t, supplied in accordance with the ISO protocols.~~

~~**<u>Prices</u>**. The prices in the Settlement process for Spinning Reserve shall be those determined in Section 2.5.15 for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level.~~

~~$Adjustment$ = penalty described in Section 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.~~

~~$PspDA_{xt}$ = market clearing price, Psp, in Zone X for Spinning Reserve capacity in the Day-Ahead Market for Settlement Period t.~~

~~**<u>Payments</u>**. Scheduling Coordinators for Generating Units, System Units, or System Resources providing Spinning Reserve capacity through the ISO auction shall receive the following payments for Spinning Reserve capacity:~~

~~$SpinPay_{xt} = SpinQDA_{xt} * PspDA_{xt - Adjustment}$~~

~~Scheduling Coordinators for Generating Units, System Units, or System Resources shall receive the following payments for Energy output from Spinning Reserve capacity:~~

~~$EnQInst_{xt} * BEEP\ Interval\ Ex\ Post\ Price_{xt}$~~

2.5.27.3 [Not Used] ~~Non-Spinning Reserve.~~

~~**Quantities.** The following quantity definitions shall be used for each Scheduling Coordinator in the settlement process:~~

~~$NonSpinQDA_{xt}$ = the Scheduling Coordinator's total Quantity of Non-Spinning Reserve capacity in Zone X sold through the ISO's auction at bids at or below the level specified in Section 2.5.27.7, and scheduled Day-Ahead for Settlement Period t.~~

~~$EnQInst_{xt}$ = Instructed Imbalance Energy output or Demand reduction in Zone X in real time Dispatch for Settlement Period t, supplied in accordance with the ISO protocols.~~

~~**Prices.** The prices in the Settlement process for Non-Spinning Reserve shall be those determined in Section 2.5.16 for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level.~~*Adjustment* ~~= penalty described in section 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.~~

~~$PnonspDA_{xt}$ = market clearing price, Pnonsp, in Zone X for Non-Spinning Reserve capacity in the Day-Ahead Market for Settlement Period t.~~

~~**Payments.** Scheduling Coordinators for Generating Units, System Units, System Resources, or Loads supplying Non-Spinning Reserve capacity through the ISO auction shall be paid the following for the Non-Spinning Reserve capacity:~~

$\cancel{NonspPay_{xt} = NonSpinQDA_{xt} * PnonspDAxt - Adjustment}$

~~Scheduling Coordinators for Generating Units, System Units, System Resources or Loads shall receive the following payments for Energy output from Non-Spinning Reserve capacity:~~

~~*EnQInst*$_{xt}$ * *BEEP Interval Ex Post Price*$_{xt}$~~

2.5.27.4 [Not Used] ~~Replacement Reserve.~~

~~**Quantities.** The following quantity definitions shall be used for each Scheduling Coordinator in the settlement process:~~

~~$RepResQDA_{xt}$ = the Scheduling Coordinator's total quantity of Replacement Reserve capacity in Zone X sold through the ISO auction at bids at or below the level specified in Section 2.5.27.7, scheduled Day-Ahead for Settlement Period t, and from which Energy has not been generated.~~

~~$EnQInst_{xt}$ = Instructed Imbalance Energy output or Demand reduction in Zone X in real time Dispatch for Settlement Period t, suppplied in accordance with the ISO protocols.~~

~~**Prices.** The prices in the settlement process for Replacement Reserve shall be those determined in section 2.5.17 for bids at or below the level specified in Section 2.5.27.7 and prices determined in accordance with Section 2.5.27.7 for bids above that level.~~

~~*Adjustment* = penalty described in section 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.~~

~~$PRepResDA_{xt}$ = market clearing price, PRepRes, in Zone X for Replacement Reserve capacity in the Day-Ahead Market for Settlement Period t.~~

~~**Payments.** Scheduling Coordinators for Generating Units, System Units, System Resources, or Loads providing Replacement Reserve capacity through the ISO auction shall receive the~~

~~following payments for the portion of a Scheduling Coordinator's Replacement Reserve capacity from which Energy has not been generated:~~

~~$RepResPay_{ijt} = (RepResQDA_{xt} -) * PRepResDA_{xt\ Adjustment}$~~

~~Scheduling Coordinators shall not receive capacity payments for the portion of a Scheduling Coordinator's Replacement Reserve capacity from which Energy has been generated. The payments for Energy output from Replacement Reserve capacity are calculated as follows:~~

~~$EnQInst_{ijt} * BEEP\ Interval\ Ex\ Post\ Price_{xt}$~~

2.5.27.5 [Not Used] ~~Voltage Support.~~ ~~The total payments for each Scheduling Coordinator shall be the sum of the short-term procurement payments, based on opportunity cost, as described in Section 2.5.18, and the payments under long term contracts.~~

2.5.27.6 [Not Used] ~~Black Start.~~

~~**Quantities.** The following quantities shall be used in the Settlement process:~~

~~$EnQBS_{ijt}$ = Energy output from Black Start made by Generating Unit i from Scheduling Coordinator j (or Black Start Generator j, as the case may be) for Settlement Period t, pursuant to the ISO's order to produce.~~

~~**Prices.** The prices used in the Settlement process are those described in the contracts referred to in section 2.5.19.~~

~~*Adjustment* = penalty described in section 2.5.26.1.~~

~~**Payments.**~~

~~Scheduling Coordinators for owners of Reliability Must-Run Units (or Black Start Generators, as the case may be) shall receive the following payments for Energy output from Black Start facilities:~~

$$\cancel{BSEN_{ijt}=(EnQBS_{ijt}*EnBid_{ijt})+BSSUP_{ijt\text{-}Adjustment}}$$

~~where BSSUPijt is the start-up payment for a Black Start successfully made by Generating Unit i of Scheduling Coordinator j (or Black Start Generator j) in Trading Interval t calculated in accordance with the applicable Reliability Must-Run Contract (or the Interim Black Start agreement as the case may be).~~

2.5.27.7 [Not Used] ~~Temporary Limitation on Ancillary Service Prices.~~

~~Notwithstanding any other provision of the ISO Tariff, the Market Clearing Prices for Regulation Up, Regulation Down, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves shall not exceed $150. Scheduling Coordinators for Generating Units, System Units, Loads, and System Resources that submit bids above $150 for the supply of these Ancillary Services shall be paid in accordance with their bids if accepted by the ISO.~~

2.5.28 [Not Used] ~~Settlement for User Charges for Ancillary Services.~~

~~(a) The ISO shall determine a separate hourly user rate for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve for each Settlement Period purchased in the Day-Ahead market, and in the Hour-Ahead Market. Each rate will be charged to Scheduling Coordinators on a volumetric basis applied to each Scheduling Coordinator's obligation for the Ancillary Service concerned which it has not self provided, as adjusted by any Inter-Scheduling Coordinator Ancillary Service Trades. Each Scheduling Coordinator's obligation for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve for each Zone shall be calculated in accordance with Section 2.5.20.1, notwithstanding any~~

~~adjustment to the quantities of each Ancillary Service purchased by the ISO in accordance with Section 2.5.3.6.~~

~~The cost of Voltage Support and Black Start shall be allocated to Scheduling Coordinators as described in Sections 2.5.28. Quantities and rates for the Hour-Ahead markets shall be calculated by substituting the Hour-Ahead quantities and prices in the relevant formulae (including self provided quantities of the Ancillary Service) except that the user rates for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve capacity shall be calculated by dividing the net payments made by the ISO for each service by the MW quantity purchased for each service. The net payments are the total payments for each service net of sums payable by Scheduling Coordinators who have bought back in the Hour-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity, as the case may be, which they had sold to the ISO in the Day-Ahead Market.~~

~~Ancillary Services obligations may be negative, and credits for such negative obligations will be in accordance with the rates calculated in Sections 2.5.28.1, 2.5.28.2, 2.5.28.3 and 2.5.28.4, except that a Scheduling Coordinator's credit shall be reduced by the greater of: a) the amount of any self-provision scheduled from resources which are deemed to meet the ISO's Ancillary Services standards, and which are not subject to the certification and testing requirements of the ISO Tariff; or b) if the ISO has no incremental requirement to be met in the Hour-Ahead Market for an Ancillary Service, the incremental amount of such service scheduled by that Scheduling Coordinator in the Hour-Ahead Market.~~

~~The ISO will allocate the Ancillary Services capacity charges, for both Day-Ahead and Hour-Ahead Markets, on a Zonal basis if the Day-Ahead Ancillary Services market is procured on a Zonal basis. The ISO will allocate the Ancillary Services capacity charges, for both the~~

~~Day-Ahead and Hour-Ahead Markets, on an ISO Control Area wide basis if the Day-Ahead Ancillary Services market is defined on an ISO Control Area wide basis.~~

~~(b) If, in any Settlement Period, no quantity of Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve is purchased in the Day-Ahead Market or the Hour-Ahead Market due to the operation of Section 2.5.3.6, then in lieu of the user rate determined in accordance with Section 2.5.28.1, 2.5.28.2, 2.5.28.3, or 2.5.28.4, as applicable, the user rate for the affected Ancillary Service for that Settlement Period shall be determined as follows:~~

~~(i) If the affected market is a Day-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Day-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the lowest Market Clearing Price for the same Settlement Period established in the Day-Ahead Market for another Ancillary Service that meets the requirements for the affected Ancillary Service.~~

~~(ii) If the affected market is an Hour-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Hour-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the user rate for the same Ancillary Service in the Day-Ahead Market in the same Settlement Period.~~

~~(c) With respect to each Settlement Period, in addition to the user rates determined in accordance with Sections 2.5.28.1 through 2.5.28.4 or Section 2.5.28(b), as applicable, each Scheduling Coordinator shall be charged an additional amount equal to its proportionate share,~~

~~based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators pursuant to Section 2.5.27.1 through 2.5.27.4, for the Day-Ahead Market and Hour-Ahead Market and all Zones, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to Section 2.5.28.1 through 2.5.28.4, for the Day-Ahead Market and Hour-Ahead Market and all Zones. If total amounts charged to Scheduling Coordinators exceed the total payments to Scheduling Coordinators, each Scheduling Coordinator will be refunded its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve.~~

2.5.28.1 **[Not Used]** ~~**Regulation.** Regulation Up and Regulation Down charges shall be calculated separately. The user rate per unit of purchased Regulation service for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total Regulation capacity payments by the ISO's total MW purchases of Regulation for that Settlement Period for that Zone which has not been self provided by Scheduling Coordinators. The ISO will calculate the user rate for Regulation Up in each Zone for each Settlement Period as:~~

~~$RegRateUpDA\ (\$/MW) = AGCUpPayDA / AGCUpPurchDA$~~

~~where:~~

~~$AGCUpPayDA$ = Total Regulation Up payments for the Settlement Period in the Day-Ahead Market for the Zone.~~

~~$AGCUpPurchDA$ = the total ISO Regulation Up MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self provided by Scheduling Coordinators.~~

~~The ISO will calculate the user rate for Regulation Down in each Zone for each Settlement Period as:~~

~~*RegRateDownDA ($/MW) = AGCDownPayDA /AGCDownPurchDA*~~

~~where:~~

~~*AGCDownPayDA* = Total Regulation Down payments for the Settlement Period in the Day-Ahead Market for the Zone.~~

~~*AGCDownPurchDA* = the total ISO Regulation Down MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self provided by Scheduling Coordinators.~~

~~For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:~~

~~*RegRateUpDA * AGCUpOblig*~~

~~where *AGCUpOblig* is the Scheduling Coordinator's obligation for Regulation Up in the Zone in the Settlement Period for which it has not self provided.~~

~~*RegRateDownDA * AGCDownOblig*~~

~~where *AGCDownOblig* is the Scheduling Coordinator's obligation for Regulation Down in the Zone in the Settlement Period for which it has not self provided.~~

2.5.28.2 **[Not Used]** ~~**Spinning Reserve.** The user rate per unit of purchased Spinning Reserve for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total capacity payments for Spinning Reserve by the ISO's total MW purchases of Spinning Reserve for that Settlement Period for that Zone which has not been self-provided by~~

~~Scheduling Coordinators. The ISO will calculate the user rate for Spinning Reserve in each Zone for each Settlement Period as:~~

~~$SpRateDA(\$/MW) = \frac{SpinPayDA}{SpinPurchDA}$~~

~~where:~~

~~$SpinPayDA$ = Total Spinning Reserve payments for the Settlement Period in the Market for the Zone Day-Ahead.~~

~~$SpinPurchDA$ = the total ISO Spinning Reserve MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self provided by Scheduling Coordinators.~~

~~For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:~~

~~$SPRateDA * SpinOblig$~~

~~where $SpinOblig$ is the Scheduling Coordinator's obligation for Spinning Reserve in the Zone in the Settlement Period for which it has not self-provided.~~

2.5.28.3 **[Not Used]** ~~**Non-Spinning Reserve.** The user rate per unit of purchased Non-Spinning Reserve for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total capacity payments for Non-Spinning Reserve by the ISO's total MW purchases of Non-Spinning Reserve for that Settlement Period for that Zone which has not been self provided by Scheduling Coordinators. The ISO will calculate the user rate for Non-Spinning Reserve in each Zone for each Settlement Period as:~~

~~$NonSpRateDA(\$/MW) = \frac{NonSpinPayDA}{NonSpinPurchDA}$~~

~~where:~~

~~$NonSpinPayDA$ = Total Non-Spinning Reserve payments for the Settlement Period in the Day-Ahead Market for the Zone.~~

~~$NonSpinPurchDA$ = the total ISO Non-Spinning Reserve MW purchases for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.~~

~~For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:~~

~~$NonSpRateDA * NonSpinOblig$~~

~~where $NonSpinOblig$ is the Scheduling Coordinator's obligation for Non-Spinning Reserve in the Zone in the Settlement Period for which it has not self provided.~~

2.5.28.4 [Not Used] ~~**Replacement Reserve.** The user rate per unit of Replacement Reserve obligation for each Settlement Period t for each Zone x shall be as follows:~~

$$\cancel{ReplRate_{xt} = \frac{(PRepResDA_{xt} * OrigReplReqDA_{xt}) + (PRepResHA_{xt} * OrigReplReqHA_{xt})}{OrigReplReqDA_{xt} + OrigReplReqHA_{xt}}}$$

~~where~~

~~$OrigReplReqDA_{xt}$ = Replacement Reserve requirement net of self-provision in the Day-Ahead Market before consideration of any substitutions pursuant to Section 2.5.3.6.~~

~~$OrigReplReqHA_{xt}$ = Incremental change in the Replacement Reserve requirement net of self-provision between the Day-Ahead Market and the Hour-Ahead Market before consideration of any substitutions pursuant to Section 2.5.3.6.~~

~~$PRepResDA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Day-Ahead Market for Zone x in Settlement Period t.~~

~~$PRepResHA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Hour-Ahead Market for Zone x in Settlement Period t.~~

~~For each Settlement Period t, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone $_x$:~~

~~$ReplRate_{xt} * ReplOblig_{jxt}$~~

~~where~~

~~$ReplOblig_{jxt} = DevReplOblig_{jxt} + RemRepl_{jxt} - SelfProv_{jxt} + NetInterSCTrades_{jxt}$~~

~~$DevReplOblig_{jxt}$ is the Scheduling Coordinator’s obligation for deviation Replacement Reserve in Zone x in the Settlement Period t and $RemRepl_{jxt}$ is the Scheduling Coordinator’s obligation for remaining Replacement Reserve in Zone x for Settlement Period t.~~

~~$SelfProv_{jxt}$ is Scheduling Coordinator's Replacement Reserve self provision in Zone x for Settlement Period t.~~

~~$NetInterSCTrades_{jxt}$ is the sale of Replacement Reserve less the purchase of Replacement Reserve through Inter-Scheduling Coordinator Trades by Scheduling Coordinator j in Zone x for Settlement Period t.~~

~~Deviation Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:~~

~~If $ReplObligTotal_{xt} > TotalDeviations_{xt}$ then:~~

$$DevReplOblig_{xjt} = \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right) \right]$$

~~If $ReplObligTotal_{xt} < TotalDeviations_{xt}$ then:~~

$$DevReplOblig_{xjt} = \frac{ReplObligTotal_{xt}}{TotalDeviations_{xt}} * \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

~~where,~~

$$TotalDeviations_{xt} = \sum_j \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]$$

~~$GenDev_{ijxt}$ = The deviation between scheduled and actual Energy Generation for Generator i represented by Scheduling Coordinator j in Zone x during Settlement Period t as referenced in SABP Appendix D.~~

~~$LoadDev_{ijxt}$ = The deviation between scheduled and actual Load consumption for resource i represented by Scheduling Coordinator j in Zone x during Settlement Period t as referenced in SABP Appendix D.~~

~~$DevReplOblig_{xt}$ is total deviation Replacement Reserve in Zone x for Settlement Period t.~~
~~$ReplObligTotal_{xt}$ is total Replacement Reserve Obligation in zone x for Settlement Period t.~~

~~Remaining Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:~~

$$RemRepl_{xjt} = \frac{MeteredDemand_{jxt}}{TotalMeteredDemand_{xt}} * TotalRemRepl_{xt}$$

~~where:~~

~~$MeteredDemand_{jxt}$ is the Scheduling Coordinator's total metered Demand excluding exports in Zone x for Settlement Period t.~~

~~$TotalMeteredDemand_{xt}$ is total metered Demand excluding exports in Zone x for Settlement Period t.~~

~~$TotalRemRepl_{xt} = Max[0, ReplObligTotal_{xt} + TotalSelfProv_{xt} - DevReplOblig_{xt}]$~~

2.5.28.5 [Not Used] ***~~[Refer to SABP Appendix G.]~~*****~~Voltage Support.~~** ~~The short term market Voltage Support user rate for Settlement Period t for Zone x shall be calculated as follows:~~

$$\cancel{VSSTRate_{xt} = \frac{\sum_{i,j} VSST_{xijt}}{\sum_{j} QChargeVS_{xjt}}}$$

~~$VSST_{xijt}$ = Voltage Support payment to Scheduling Coordinator j in respect of Generating Unit i in Zone x in the short-term market applicable to Settlement Period t.~~

~~$QChargeVS_{xjt}$ = charging quantity for Voltage Support for Scheduling Coordinator j for Settlement Period t in Zone x equal to the total metered Demand in Zone x (including exports to neighboring Control Areas and excluding metered Demand inside an MSS) by Scheduling Coordinator j for Settlement Period t.~~

~~The monthly long term Voltage Support contract user rate for Settlement Period t for Zone x shall be calculated as follows:~~

$$\cancel{VSLTRate_{xm} = \frac{\sum_{i,j} VSLT_{xijm}}{\sum_{jm} QChargeVS_{xjt}}}$$

~~where:~~

~~$VSLT_{xijm}$ = long term Voltage Support contract payment to Scheduling Coordinator j for owner of Reliability Must-Run Unit i in Zone x for month m.~~

~~The short term market Voltage Support charges for Settlement Period t payable by Scheduling Coordinator j will be calculated as follows:~~

$$\cancel{VSSTCharge_{jt} = VSSTRate_t * QChargeVS_{jt}}$$

~~where $VSSTCharge_{jt}$ is the amount payable by Scheduling Coordinator j for short term market Voltage Support for Settlement Period t.~~

~~$VSSTRate_t$ is the short term market Voltage Support user rate for Settlement Period t.~~

~~The monthly long term Voltage Support contract charge for month m payable by Scheduling Coordinator j will be calculated as follows:~~

$$\cancel{VSLTCharge_m = VSLTRate_m * \sum_m QChargeVS_{jt}}$$

~~where $VSLTCharge_m$ is the amount payable by Scheduling Coordinator j for long term Voltage Support for month m.~~

~~$VSLTRate_m$ is the monthly long term Voltage Support contract user rate charged by the ISO to Scheduling Coordinators for month m.~~

2.5.28.6 <u>[Not Used]</u> ~~[Refer to SABP Appendix G.] Black Start.~~

~~$QChargeBlackstart_{jt}$ = charging quantity for Black Start for Scheduling Coordinator j for Settlement Period t equal to the total metered Demand (excluding exports to neighboring Control Areas and metered Demand of a MSS in accordance with Section 3.3.4.5) by Scheduling Coordinator j for Settlement Period t.~~

~~The Black Start Energy payment user rate for Settlement Period t will be calculated as follows:~~

$$\cancel{BSRate_t =} \frac{\sum_{i,j} BSEn_{ijt}}{\sum_{j} QChargeBlackstart_{jt}}$$

~~where $BSEn_{ijt}$ is the ISO payment to Scheduling Coordinator j for owner of Reliability Must-Run Unit (or to Black Start Generator j, as the case may be) for Generating Unit i providing Black Start Energy in Settlement Period t.~~

~~The Black Start Energy user charge for Settlement Period t for Scheduling Coordinator j will be calculated as follows:~~

$$\cancel{BSCharge_{jt} = BSRate_t * QChargeBlackStart_{jt}}$$

2.5.29 Public Dissemination of Information: Day-Ahead.

By 3:00 p.m. of the day preceding the Trading Day, the ISO shall make available to all Market Participants the following information on the scheduling of Ancillary Services:Ancillary Service	Quantity Units	Period	Ancillary Services Region	Ancillary Services Marginal Price ~~Clearing Price~~~~Clearing Prices~~
Regulation/AGC	MW	Hourly	Region	$/MW
Spinning Reserve	MW	Hourly	Region	$/MW
Non-spinning Reserve	MW	Hourly	Region	$/MW

~~Replacement Reserve~~	~~MW~~	~~Hourly~~		~~$/MW~~
~~Black Start~~	~~MW~~	~~Annual~~		~~$/MW~~

* * *

3. RELATIONSHIP BETWEEN ISO AND PARTICIPATING TOs.

* * *

3.3.4.2 provide the ISO Outage Coordination Office **by October 15 of** each year with a schedule **for the next calendar year** of upcoming maintenance of facilities forming part of the MSS that will affect or is reasonably likely to affect the ISO Controlled Grid in accordance with Section 2.3.3.5. **In addition, on the first day of every month the MSS shall provide an update of any known changes to any previously planned Maintenance Outages and additional Outages anticipated over the next two months (i.e. On January 1, the MSS would report updated information for February and March)**;

* * *

3.3.4.6 be responsible for ~~Intra-Zonal~~ Congestion Management and transmission line Outages within or at the boundary of the MSS, and all associated costs and not responsible for ~~Intra-Zonal~~ Congestion Management elsewhere in the **ISO Control Area**~~zone~~ except to the extent that a Scheduling Coordinator is delivering Energy to or from the MSS.

* * *

3.3.14.2.3 shall obtain ISO certification of the System Unit's Ancillary Service capabilities in accordance with Section 2.5.6 and 2.5.24 before the Scheduling Coordinator representing the MSS may self-provide its Ancillary Service obligations or bid into the ISO's markets from that System Unit;

* * *

4. RELATIONSHIP BETWEEN ISO AND UDCS.

* * *

4.3 UDC Responsibilities.

Recognizing the ISO's duty to ensure efficient use and reliable operation of the ISO Controlled Grid consistent with the Applicable Reliability Criteria, each UDC shall:

4.3.1 operate and maintain its facilities, in accordance with applicable safety and reliability standards, regulatory requirements, applicable operating guidelines, applicable rates, tariffs, statutes and regulations governing their provision of service to their End-Use Customers and Good Utility Practice so as to avoid any material adverse impact on the ISO Controlled Grid;

4.3.2 provide the ISO Outage Coordination Office each year with a schedule of upcoming maintenance that has a reasonable potential of impacting the ISO Controlled Grid in accordance with Section 2.3.3.5 of this ISO Tariff **<u>and provide by the first day of every month an update of any known changes to the schedule anticipated over the next two months (i.e. on January 1, the UDC would report updated information for February and March)</u>;** and

* * *

5. RELATIONSHIP BETWEEN ISO AND GENERATORS.

* * *

5.2.1.1 If the ISO, pursuant to Section 2.5.12(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 2.5.3.6), except that the ISO shall not be required to accept bids that exceed price caps imposed by the ISO or the FERC.

5.2.1.2 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 2.5.3.6) have been selected pursuant to Section 2.5.21, 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 5.2.1.2; 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 5.2.1.1. The ISO must provide the notice specified in paragraph (3) of this Section 5.2.1.2 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 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 2.5.3.6) 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 2.5.12 ("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.

* * *

5.11 [Not Used] ~~Must-Offer Obligations~~

5.11.1 [Not Used]

5.11.2 [Not Used] ~~Available Generation~~

~~For the purposes of this Section 5.11, a Generating Unit's "Available Generation" for Generating Units bidding into the Residual Unit Commitment Process 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 2.3 or 5.11.3 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, if any, as identified in the ISO's~~

~~Final Day-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) if the Generating Unit is owned by a load serving entity, minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the load serving entity's Native Load. A Generating Unit's "Available Generation" for Generating Units bidding into the ISO Real Time Imbalance Energy Market 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 2.3 or 5.11.3 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, if any, 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, (d) if the Generating Unit is owned by a load serving entitity, minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the load serving entity's Native Load and (e) minus the Generating Unit's capacity committed to provide Energy through the ISO's Residual Unit Commitment Process but not included in the Generating Unit's scheduled operating point as identified in the ISO's Final Hour-Ahead Schedule.~~

5.11.3 [Not Used]

5.11.4 [Not Used] ~~Obligation To Offer Available Capacity~~

~~All Participating Generators shall offer to sell in the ISO's Residual Unit Commitment Process, in all hours, all Available Generation from non-hydroelectric Generating Units owned or controlled by the Participating Generators. All Participating Generator shall offer to sell in the ISO's Real Time Market, in all hours, all Available Generation from non-hydroelectric Generating Units (except Generating Units with ~~~~startupstart-up~~ ~~times of greater than 10 minutes).~~

5.11.5 <u>[Not Used]</u>~~Submission of Bids and Default Bids~~

~~The Scheduling Coordinators for Participating Generators required to offer Available Generation in the Real Time market under section 5.11.4 shall submit Supplemental Energy bids for such Available Generation for each BEEP Interval. If a Scheduling Coordinator for a Participating Generator required to offer Available Generation in the Real Time market under section 5.11.4 fails tp submit Supplemental Energy bids for any such Available Generation for any BEEP Interval, the unbid quantity of the Available Generation will be deemed by the ISO to be bid at the Default Bid for Energy calculated under Section 5.12~~

5.12 Residual Unit Commitment

5.12.1 Purpose. The Residual Unit Commitment process allows the ISO to acquire enough resources to meet the Demand, including any Operating Reserve or other capacity requirements projected by the ISO for each hour of the next Trading Day.

5.12.2 Participation.

5.12.2.1 Non-hydroelectric Generating Units subject to a Participating Generating Agreement. **<u>The ISO shall use unused Day-Ahead Energy Bids from</u>** Scheduling Coordinators **<u>for</u>**~~must bid~~ all non-hydroelectric Generating Units subject to a Participating Generator Agreement into the Residual Unit Commitment Process as set forth in Section 5.12.5.1.

5.12.2.2 Hydroelectric Generating Units subject to a Participating Generator Agreement. Scheduling Coordinators for hydroelectric Generating Units subject to a Participating Generator Agreement or other Generating Units not subject to a Participating Generator Agreement ~~may~~ **<u>shall indicate to the ISO if they want any unused Day-Ahead Energy Bid to participate</u>**~~bid~~ in ~~to~~ the Residual Unit Commitment Process as set forth in Section 5.12.5.1.

5.12~~2.12.~~3 **System Resources.** Scheduling Coordinators **shall indicate to the ISO if they want any unused Day-Ahead Energy Bid from** ~~may submit~~ System Resources **to participate** ~~for participation~~ in the Residual Unit Commitment Process as set forth in Section 5.12.5.2.

5.12.2.4 **Dispatchable Load~~Curtailable Demand~~.** Scheduling Coordinators **shall indicate to the ISO if they want any unused Day-Ahead Energy Bid from** ~~may submit bids~~ for **Dispatchable Load**~~Curtailable Demand~~ **to participate** in the Residual Unit Commitment Process as set forth in Section 5.12.5.3.

5.12.2.5 **System Units.** Scheduling Coordinators **shall indicate to the ISO if they want any unused Day-Ahead Energy Bid from** ~~may submit bids~~ for System Units **to participate** in the Residual Unit Commitment Process as set forth in Section 5.12.5.4.

5.12.3 Data to be Submitted.

5.12.3.1 Scheduling Coordinators for Generating Units required to **participate in** ~~bid~~ or voluntarily **participating in** ~~bidding into~~ the Residual Unit Commitment Process shall submit the following information to the ISO in the form as specified by the ISO and posted on the ISO Home Page. Scheduling Coordinators for such Generating Units 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 5.12.3.1 as confidential and will apply the procedures in Section 20.3.4 of this ISO Tariff with regard to requests for disclosure of such information.

5.12.3.1.1 **Gas-fired Generating Units.** Data to be submitted for these Generating Units shall include: heat input data, minimum load level, start-up fuel data, start-up auxiliary power data, minimum run time, minimum off time, ramp rates, emissions rates and costs, start-up emissions data and costs, energy limitations, and the maximum number of start-ups per day.

5.12.3.1.2 Non-gas-fired Generating Units. Data to be submitted for these Generating Units shall include: a cost curve relating the unit's average cost to its output, minimum load level, start-up fuel data, start-up auxiliary power data, minimum run time, minimum off time, ramp rates, emissions rates and costs, start-up emissions data and costs, energy limitations, and the maximum number of start-ups per day.

5.12.3.1.3 Default information. If a Scheduling Coordinator for a Non-hydroelectric Generating Unit subject to a Participating Generating Agreement fails to submit the data required by this section 5.12.3, the ISO shall determine the unsubmitted data for that Generating Unit by using data previously submitted to the ISO, by using data from a unit of similar size and technology, or by using data from Schedule 1 in the Participating Generator Agreement in which that Generating Unit is listed.

5.12.4 Timing of the Residual Unit Commitment Process.

5.12.4.1 Submission of bids. **The Residual Unit Commitment Process uses bids submitted to the Day-Ahead market.** Scheduling Coordinators **shall notify the ISO of whether they want unused Day-Ahead Energy Bids to participate in the Residual Unit Commitment Process when they submit their Bids to the Day-Ahead Market.**~~submit bids to the Residual Unit Commitment Process no later than one-half hour after the ISO issues Final Day-Ahead Schedules.~~

5.12.4.2 ISO Notification. The ISO shall conduct the Residual Unit Commitment Process **one-half hour after Final Day-Ahead Schedules are published** ~~after bids are submitted~~ and shall notify Scheduling Coordinators for those Generating Units, System Units, **Dispatchable Loads**~~Curtailable Demands~~ and System Resources selected in the Residual Unit Commitment Process no later than two hours after Final Day-Ahead Schedules are issued.

5.12.5 ~~**Structure of Bids.** Scheduling Coordinators shall submit bids to the Residual Unit Commitment Process in the relevant forms set forth below.~~ **Transmission for System Resources in the Residual Unit Commitment Process**

(a) Transmission Outside the ISO Control Area

System Resources selected by the ISO in the Residual Unit Commitment Process must obtain transmission service to the ISO Control Area.

(b) ISO Control Area Transmission

The ISO shall provide transmission service within the ISO Control Area to System Resources selected by the ISO in the Residual Unit Commitment Process after the Day-Ahead or Hour-Ahead Energy Markets, as appropriate.

5.12.5.1 **[Not Used]**~~**Non-Hydroelectric Generating Units subject to a Participating Generator Agreement.** Scheduling Coordinators shall submit three-part bids to the Residual Unit Commitment Process for each such Generating Unit which consist of the following parts:~~

5.12.5.1.1 **[Not Used]**~~**Start-up Cost.** Scheduling Coordinators shall submit a bid of a figure, in dollars, representing the cost of the fuel and auxiliary power consumed by the Generating Unit during start-up. A Scheduling Coordinator's bid shall be reduced to equal a cost-based bid determined by the ISO using the information provided in accordance with Section 5.12.3, the proxy figure for natural gas costs posted on the ISO Home Page, and recent prices in the ISO Real Time Imbalance Energy Market, if that bid exceeds the bid so determined by the ISO.~~

5.12.5.1.2 **[Not Used]**~~**Minimum Load Cost.** Scheduling Coordinators shall submit a bid of a figure, in dollars, representing the cost of the fuel consumed each hour by the unit when is operating at its minimum load level. This figure shall be the same for each hour. A Scheduling Coordinator's bid shall be reduced to equal a cost-based bid determined by the ISO using the~~

~~information provided in accordance with Section 5.12.3, a variable operations and maintenance cost of $6.00/MWh and the proxy figure for natural gas costs posted on the ISO Home Page if that bid exceeds the bid so determined by the ISO.~~

5.12.5.1.3 **[Not Used]~~Energy bid.~~** ~~Scheduling Coordinators shall submit a monotonically increasing curve, consisting of no more than 10 segments, representing the energy payment (in $/MW per hour) requested at a particular output over the range from the Generating Unit's lowest stable sustainable output to the Generating Unit's maximum stable sustainable output for each hour. The price for energy at a given output in the curve bid into the ISO's Real Time Imbalance Energy Market for capacity selected by the ISO in the Residual Unit Commitment Process from the same Generating Unit cannot exceed the price for the same output in the energy curve bid into the Residual Unit Commitment Process for the same hour.~~

5.12.5.1.4 **Default Bids.** **The ISO shall use the same default bids for the Residual Unit Commitment Process that the ISO used in the Day-Ahead Market.** ~~If a Scheduling Coordinator for a non-Hydroelectric Generating Unit subject to a Participating Generator Agreement required to bid into the Residual Unit Commitment Process in accordance with Section 5.11.4 fails to submit a bid into the Residual Unit Commitment Process, the ISO shall submit a bid on its behalf which consists of the following parts:~~

5.12.5.1.4.1 **[Not Used] ~~Gas-Fired Generating Units subject to a Participating Generating Agreement.~~**

5.12.5.1.4.1.1 **[Not Used] ~~Default Start-Up Costs.~~** ~~The ISO shall submit a bid, based on the information provided in accordance with Section 5.12.3, the proxy figure for natural gas costs posted on the ISO Home Page, and recent prices in the ISO's Real Time Imbalance Energy market of a figure, in dollars, equal to the cost of the fuel and auxiliary power consumed by the Generating Unit during start-up.~~

5.12.5.1.4.1.2 [Not Used]~~Default Minimum Load Costs.~~ ~~The ISO shall submit a bid, based on the information provided in accordance with Section 5.12.3 of a figure, in dollars, equal to the sum of 1) the product of a) the Generating Unit's minimum load level as set forth in that Generating Unit's Participating Generator Agreement, b) the heat input characteristic of that Generating Unit at the minimum load level as set forth in Schedule 1 to that Generating Unit's Participating Generator Agreement, and c) the proxy figure for natural gas costs posted on the ISO Home Page and 2) the product of a) the Generating Unit's minimum load level as set forth in that Generating Unit's Participating Generator Agreement and b) $6.00.~~=

5.12.5.1.4.1.3 [Not Used] ~~Default Energy Bid.~~ ~~The ISO shall submit a monotonically increasing curve consisting of ten segments, representing the relationship between the Generating Unit's incremental variable operating cost and its output as calculated by the ISO based on the data provided to the ISO in accordance with Section 5.12.3, the proxy figure for natural gas costs posted on the ISO Home Page, and a variable operating and maintenance costs of $6.00/MWh, over the range from the Generating Unit's lowest stable sustainable output to the Generating Unit's maximum stable sustainable output. This curve shall be the same for each hour of the Trading Day.~~

5.12.5.1.4.2 [Not Used]~~Non-Gas-Fired Non-Hydroelectric Generating Units subject to a Participating Generating Agreement.~~

5.12.5.1.4.2.1 [Not Used]~~Default Start-Up Costs.~~ ~~The ISO shall submit a bid, based on the information provided in accordance with Section 5.12.3 and recent prices in the ISO's Real Time Imbalance Energy market of a figure, in dollars, equal to the cost of the fuel and auxiliary power consumed by the Generating Unit during start-up.~~

5.12.5.1.4.2.2 [Not Used]~~Default Minimum Load Costs.~~ ~~The ISO shall submit a bid, based on the information provided in accordance with Section 5.12.3 of a figure, in dollars, equal to the sum of 1) the product of a) the Generating Unit's minimum load level as set forth in that Generating Unit's Participating Generator Agreement, and b) the cost of that Generating Unit at~~

~~the minimum load level as set forth in Schedule 1 to that Generating Unit's Participating Generator Agreement and 2) the product of a) the Generating Unit's minimum load level as set forth in that Generating Unit's Participating Generator Agreement and b) $6.00. This bid shall be the same for each hour.~~

5.12.5.1.4.2.3 [Not Used] ~~**Default Energy bid.** The ISO shall submit a monotonically increasing curve consisting of ten segments, representing the relationship between the Generating Unit's incremental variable operating cost and its output as calculated by the ISO based on the data provided to the ISO in accordance with Section 5.12.3 over the range from the Generating Unit's lowest stable sustainable output to the Generating Unit's maximum stable sustainable output. This curve shall be the same for each hour of the Trading Day.~~

5.12.5.2 [Not Used] ~~**Hydro-electric Generating Units subject to a Participating Generator Agreement.** Scheduling Coordinators may submit three-part bids to the Residual Unit Commitment Process for each such Generating Unit which consists of the following parts:~~

5.12.5.2.1 [Not Used] ~~**Start-up Cost.** Scheduling Coordinators shall submit a bid of a figure, in dollars, representing the cost of the fuel and auxiliary power consumed by the Generating Unit during start-up. A Scheduling Coordinator's bid shall be reduced to equal a cost-based bid determined by the ISO using the information provided in accordance with Section 5.12.3, the proxy figure for natural gas costs posted on the ISO Home Page, and recent prices in the ISO Real Time Imbalance Energy Market, if that bid exceeds the bid so determined by the ISO.~~

5.12.5.2.2 [Not Used] ~~**Minimum Load Cost.** Scheduling Coordinators shall shall submit a bid of a figure, in dollars, representing the cost of the fuel consumed each hour by the unit when it is operating at its minimum load level. A Scheduling Coordinator's bid shall be reduced to equal a cost-based bid determined by the ISO using the information provided in accordance with Section 5.12.3, a variable operations and maintenance cost of $6.00/MWh and the proxy~~

~~figure for natural gas costs posted on the ISO Home Page if that bid exceeds the bid so determined by the ISO.~~

5.12.5.2.3 [Not Used]~~**Energy bid.** Scheduling Coordinators shall submit a monotonically increasing curve, consisting of no more than 10 segments, representing the energy payment (in $/MW per hour) requested at a particular output over the range from the Generating Unit's lowest stable sustainable output to the Generating Unit's maximum stable sustainable output for each hour. The price for energy at a given output in the curve bid into the ISO's Real Time Imbalance Energy Market for capacity selected by the ISO in the Residual Unit Commitment Process from the same Generating Unit cannot exceed the price for the same output in the energy curve bid into the Residual Unit Commitment Process for the same hour.~~

5.12.5.3 [Not Used]~~**System Resources.** Scheduling Coordinators may submit bids to the Residual Unit Commitment Process for System Resources which consist of the following parts:~~

5.12.5.3.1 [Not Used]~~ **Energy bid.** Scheduling Coordinators shall submit a monotonically increasing curve, consisting of no more than ten segments, representing the energy payment (in $/MW per hour) requested for a given level of output for each hour.~~

5.12.5.3.2 [Not Used]~~**Block bids.** Scheduling Coordinators for System Resources may submit separate bids to provide Energy for a number of contiguous hours. Each such bid shall consist of a monotonically increasing curve, consisting of no more than ten segments, representing the energy payment (in $/MW per hour) requested for a given level of output.in dollars per MWh, and the contiguous hours in which the Energy is to be provided. The Energy price curve must be the same for all hours in the same block of contiguous hours. The Energy price curve may be different for different contiguous blocks of hours.~~

5.12.5.4 **[Not Used]** ~~**Curtailable Demand.** Scheduling Coordinators may submit three-part bids to the Residual Unit Commitment Process for Curtailable Demand which consist of the following parts:~~

5.12.5.4.2 **[Not Used]** ~~**Minimum Curtailment Payment.** A figure, in dollars, representing the minimum payment for initiating a curtailment regardless of the quantity curtailed or the duration of the curtailment.~~

5.12.5.4.3 **[Not Used]** ~~**Minimum Hourly Payment.** A figure, in dollars, representing the minimum payment per hour of curtailment at the lowest MW level stated in the first segment of the energy bid curve set forth in accordance with Section 5.12.5.4.2.~~

5.12.5.4.4 [Not Used] ~~Energy bid.~~ ~~**A monotonically increasing curve, consisting of no more than ten segments, representing the energy payment (in $/MW per hour) requested to curtail a particular quantity of Demand for an hour beyond the lowest MW level stated in the first segment of the energy bid curve.**~~

5.12.5.4.5 **[Not Used]** ~~**Additional bid data.** Scheduling Coordinators may also include figures representing (a) the time, in minutes, required for curtailment following notification; (b) minimum off time, in hours, stating the minimum number of hours the Curtailable Demand is willing to be curtailed; and (c) maximum off time, in hours, stating the maximum number of hours the Curtailable Demand is willing to be curtailed.~~

5.12.5.5 **[Not Used]**~~**System Units.** Scheduling Coordinators may submit bids to the Residual Unit Commitment Process for System Units which consist of the following parts:~~

5.12.5.5.1 **[Not Used]** ~~Energy bid. A monotonically increasing curve, consisting of no more than ten segments, representing the energy payment (in $/MW per hour) requested for a given level of output for each hour.~~

5.12.6 ISO Selection of Units in the Residual Unit Commitment Process.

5.12.6.1 Procurement Target.

5.12.6.1.1 Capacity. The ISO shall select Generating Units, System Units, System Resources and **Dispatchable**~~Curtailable~~ Load in the Residual Unit Commitment Process to meet the difference between the sum of the ISO Adjusted Demand Forecast and the ISO forecast Operating Reserve Requirement for each hour in the Trading Day and the sum of the total scheduled ISO Control Area Demand and the ISO's Operating Reserve requirement as indicated in the Final Day-Ahead Schedules for each hour of the Trading Day.

5.12.6.1.1.1 ISO Adjusted Demand Forecast. The ISO Adjusted Demand Forecast is the total forecast Demand for the ISO Control Area less expected additional Energy to be delivered in the Hour Ahead and Real Time Imbalance Energy markets.

5.12.6.1.2 Energy Procurement. For each hour of the Trading Day, the sum of the (1) Energy provided as Generation in Final Day-Ahead Schedules, and (2) the Energy output at minimum load for Generating Units selected by the ISO in the Residual Unit Commitment Process and (3) Energy purchased from System Resources in the Residual Unit Commitment Process shall not exceed 95% of the ISO Adjusted Demand Forecast for that hour unless the sum of (1) the Energy provided as Generation in Final Day-Ahead Schedules, and (2) the Energy output at minimum load for Generating Units selected by the ISO in the Residual Unit Commitment Process exceeds 95% of the ISO Adjusted Demand Forecast.

5.12.6.2 Cost Minimization. The ISO shall select Generating Units, System Units, System Resources and **Dispatchable Load**~~Curtailable Demand~~ in the Residual Unit Commitment Process to minimize the total of the start-up, minimum load, and estimated Energy costs for the Residual Unit Commitment Process. To estimate Energy costs, the ISO shall project the Energy level to which the ISO will Dispatch those resources selected in the Residual Unit Commitment Process in each hour to fully meet the ISO Adjusted Demand Forecast.

5.12.6.3 Local Reliability Commitment. If required, and after using effective RMR units to the extent possible, the ISO shall select Generating Units in the Residual Unit Commitment Process that the ISO determines must be operating to comply with all applicable reliability criteria, including Generating Units that are needed to ensure local reliability.

5.12.6.4 Resource characteristics. The ISO shall consider the performance characteristics submitted by Generating Units in accordance with Section 5.12.3, including ramp rates, minimum load levels, energy limitations and other characteristics, of Generating Units, System Units, System Resources and **Dispatchable Load**~~Curtailable Demand~~ when selecting those resources in the Residual Unit Commitment Process.

5.12.7 Payments.

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5.12.7.1.1.2.5 Qualifying Hour. A Qualifying Hour shall be an Hour in the ISO Commitment Period in which ~~1) the Generating Unit is not awarded or does not self-provide an Hour-Ahead Ancillary Services schedule, and 2)~~ the ISO does not Dispatch the Generating Unit in accordance with its RMR Contract.

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5.12.7.1.1.3 Hourly Minimum Load Cost Deficiency. The Hourly Minimum Load Cost Deficiency for each hour shall be the sum, for all ~~BEEP Interval~~**Dispatch Intervals** in that hour, of the number that is the greater of zero and the Unit's Minimum Load Cost less the product of the Unit's Minimum Load Level and the ~~Market Clearing Price~~**Locational Marginal Price** for that ~~BEEP Interval~~**Dispatch Interval**.

5.12.7.1.1.3.1 Minimum Load Cost. The Minimum Load Cost shall be the sum of 1) the product of a) the Unit's average heat rate at minimum load; b) the proxy figure for natural gas costs posted on the ISO Home Page and c) the Unit's minimum load; and 2) the Unit's minimum load and $6.00.

5.12.7.1.1.4 Hourly Market Net Revenue. The Hourly Market Net Revenue for each hour shall be the sum, for all ~~BEEP Interval~~**Dispatch Intervals** in that hour, of a) the product of 1) the number that is the ~~Market Clearing Price~~**Locational Marginal Price** for that ~~BEEP Interval~~**Dispatch Interval** less the Imputed Cost and 2) the number that is the difference between the operating level instructed by the ISO and the Generating Unit's minimum load level **and b) the sum of the Day-Ahead, Hour-Ahead and real-time Ancillary Service payments**.

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5.12.7.1.3.3 Withdrawing Capacity Payments when Dispatched or Producing Uninstructed Imbalance Energy. The ISO shall make no capacity payment in a ~~BEEP Interval~~**Dispatch Interval** to the Scheduling Coordinator for a Generating Unit for the capacity from which 1) the ISO Dispatches Energy from a Generating Unit at a level above the greater of the Unit's Day-Ahead Schedule or the Minimum Load for that Unit **or 2) Uninstructed Imbalance Energy is produced**.

5.12.7.1.3.4 Withdrawing Capacity Payments for Exports. The ISO shall make no capacity payment in a ~~BEEP Interval~~**Dispatch Interval** to the Scheduling Coordinator for a Generating Unit for the capacity selected by the ISO in the Residual Unit Commitment Process if the Energy from that capacity is being exported from the ISO Control Area.

5.12.7.2 System Resources.

5.12.7.2.1 Energy. System Resources the ISO selects in the Residual Unit Commitment Process shall be paid, for each hour, the product of 1) the higher of their bid price or the simple average of the ~~six BEEP Interval~~**Dispatch Interval** **Locational Marginal Prices**~~Market Clearing~~

~~Prices~~ for that hour and 2) the operating level to which they are Dispatched in the Residual Unit Commitment Process.

5.12.7.2.2 System Resource Uplift Costs. The System Resource Uplift Costs shall be the sum, for all contiguous hours in which the System Resource is Dispatched in accordance with its bid into the Residual Unit Commitment Process in the Trading Day, of the number that is the product of 1) the operating level to which the System Resource is dispatched in the Residual Unit Commitment Process and 2) the greater of a) zero and b) the System Resource's energy bid price for the level to which the System Resource is Dispatched by the ISO less the simple average of the ~~BEEP Interval~~**Dispatch Interval Locational Marginal Price** ~~Market Clearing Prices~~ for that hour.

5.12.7.3 ~~Curtailable Demand~~Dispatchable Load.

5.12.7.3.1 Minimum Curtailment Payment. If the ISO selects ~~Curtailable Demand~~**Dispatchable Load** in the Residual Unit Commitment Process, the ISO shall pay the Scheduling Coordinator for that ~~Curtailable Demand~~**Dispatchable Load** the amount of the minimum curtailment payment in that ~~Curtailable Demand~~**Dispatchable Load**'s bid provided the ~~Curtailable Demand~~**Dispatchable Load** successfully reduces its Demand from its Final Hour Ahead Schedule at the time the ISO requests curtailment.

5.12.7.4 System Units

5.12.7.4.1 Capacity Payments. For each hour in which the ISO selects capacity from a System Unit in the Residual Unit Commitment Process the ISO shall pay to the Scheduling Coordinator for that System Unit, subject to Section 7.4.2, a payment equal to the product of

(1) the amount of capacity selected in the Residual Unit Commitment Process and

(2) the difference between the price at the System Unit's cost curve the output at which the ISO determines it expects the System Unit to be loaded at in the

Residual Unit Commitment Process and b) the cost at the operating point reflected in the System Unit's Final Day-Ahead Schedule.

5.12.7.4.2 Withdrawing Capacity Payments when Dispatched or Producing Uninstructed Imbalance Energy. The ISO shall make no capacity payment to the Scheduling Coordinator for a System Unit for the capacity from which 1) the ISO Dispatches Energy from a System Unit at a level above the operating point reflected in Final Day-Ahead Schedule **or 2) Uninstructed Imbalance Energy is produced.**

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5.12.8 Allocation of Residual Unit Commitment Process Charges.

5.12.8.1 Total Hourly Residual Unit Commitment Cost. The Total Hourly Residual Unit Commitment Cost for each hour shall be the sum of 1) the Hourly Generating Unit Commitment Costs, 2) the Hourly System Resource Commitment Costs, 3) the Hourly ~~Curtailable Demand~~**Dispatchable Load** Commitment Costs, 4) the Hourly Capacity Reservation Costs and 5) Hourly Terminated Start-Up Costs.

5.12.8.1.1 The Hourly Generating Unit Commitment Costs shall be equal to the sum, for all Generating Units selected in the Residual Unit Commitment Process for that hour, of the Generating Unit's Unrecovered Commitment Costs divided by the number of hours in each Generating Unit's ISO Commitment Period.

5.12.8.1.2 The Hourly System Resource Costs shall be equal to the sum, for all System Resources selected by the ISO for that hour, of the System Resource's System Resource Uplift Costs divided by the number of contiguous hours the System Resource was Dispatched by the ISO in accordance with the System Resource's bid in the Residual Unit Commitment Process.

5.12.8.1.3 The Hourly ~~Curtailable Demand~~**Dispatchable Load** Commitment Costs shall be equal to the sum, for all ~~Curtailable Demand~~**Dispatchable Loads** Dispatched by the ISO in that hour, of the ~~Curtailable Demand~~**Dispatchable Load**'s ~~Curtailable Demand~~**Dispatchable Load** Commitment Costs divided by the number of hours the ~~Curtailable Demand~~**Dispatchable Load** was curtailed by the ISO.

* * *

6. TRANSMISSION SYSTEM INFORMATION AND COMMUNICATIONS.

* * *

6.1 WEnet.

6.1.1 The ISO shall engage the services of an Internet Service Provider (ISP) to establish, implement and operate WEnet as a wide-band, wide-area backbone which is functionally similar to the Internet.

6.1.2 [Not Used] ~~The ISO shall provide non-discriminatory access to information concerning the status of the ISO Controlled Grid by posting that information on the public access sites on WEnet.~~

6.1.2.1 WEnet will provide an interface for data exchange between the ISO and Scheduling Coordinators who shall each have individually assigned login accounts on WEnet.

~~**6.1.2.2** The ISO shall provide public information over WEnet which shall include, at a minimum, but not limited to:~~

~~**6.1.2.2.1** Advisory Information: The following may be provided over such time scales as the ISO may in its discretion decide:~~

~~(a) Future planned transmission Outages;~~

~~(b)~~ **[Not Used]** ~~Generator Meter Multipliers.~~

~~**6.1.2.2.2** Day-Ahead and Hour-Ahead Information:~~

~~(a) Date;~~

~~(b) Hour;~~

~~(c) Total forecast Demand by UDC; Inter-Zonal Congestion price per Congested path;Total Regulation and Reserve service capacity reservation cost by Zone;~~

~~(d) Total capacity of Inter-Zonal Interfaces; and~~

~~(e) Available capacity of Inter-Zonal Interfaces.~~

~~**6.1.2.2.3** Ex Post Information:~~

~~(a) Date;~~

~~(b) Hour; and~~

~~(c) Hourly Ex Post Price.~~

~~**6.1.2.3** WEnet shall be used by the ISO to post Usage Charges for Inter-Zonal Interfaces within the ISO Controlled Grid.~~

* * *

~~**6.1.2.6** WEnet shall be used by the ISO to provide information to Market Participants regarding the ISO Controlled Grid. Such information may include but is not limited to:~~

~~(a) Voltage control parameters;~~

~~(b) ISO historical data for Congestion;~~

~~(c) Forecasts of Usage Charges; and~~

~~(d) Generation Meter Multipliers to support seven (7) day advance submission of Schedules by Scheduling Coordinators. Additional Generation Meter Multipliers may be published for different seasons and loading patterns.~~

* * *

7. TRANSMISSION PRICING.

* * *

7.1.4 Wheeling.

Any Scheduling Coordinator or other such entity scheduling a Wheeling transaction shall pay to the ISO the product of (i) the applicable Wheeling Access Charge, and (ii) the total hourly schedules of Wheeling in kilowatt-hours for each month at each Scheduling Point associated with that transaction. Schedules that include Wheeling transactions shall be subject to the Congestion Management procedures and protocols in accordance with Sections **<u>31.2.3.2.8</u>**~~7.2 and 7.3~~.

* * *

7.2 <u>[Not Used]</u> ~~Zonal Congestion Management.~~

~~7.2.1 The ISO Will Perform Congestion Management.~~

~~**7.2.1.1 Transmission Congestion**. Congestion occurs when there is insufficient transfer capacity to simultaneously implement all of the Preferred Schedules that Scheduling Coordinators submit to the ISO.~~

~~**7.2.1.2 Zone-Based Approach.** The ISO will use a Zone-based approach to manage Congestion. A Zone is a portion of the ISO Controlled Grid within which Congestion is expected~~

~~to occur infrequently or have relatively low Congestion Management costs. Inter-Zonal Interfaces consist of transmission facilities that are expected to have relatively high Congestion Management costs, as described in Section 7.2.7.1. For these interfaces, allocation of usage based on the value placed on these interfaces by the Scheduling Coordinators will increase efficient use of the ISO Controlled Grid.~~

~~**7.2.1.3 Types of Congestion.** Congestion that occurs on Inter-Zonal Interfaces is referred to as "Inter-Zonal Congestion." Congestion that occurs due to transmission system constraints within a Zone is referred to as "Intra-Zonal Congestion."~~

~~**7.2.1.4 Elimination of Potential Transmission Congestion.** The ISO's Day-Ahead and Hour-Ahead scheduling procedures will eliminate potential Congestion by:~~

~~**7.2.1.4.1** scheduling the use of Inter-Zonal Interfaces by the Scheduling Coordinators who place the highest value on those rights, based on the Adjustment Bids that are submitted by Scheduling Coordinators; and~~

~~**7.2.1.4.2** rescheduling Scheduling Coordinators' resources (but so that Intra-Zonal transmission limits are not violated) using the Adjustment Bids that are submitted by Scheduling Coordinators.~~

~~**7.2.1.5 Elimination of Real Time Inter-Zonal Congestion.** In its management of Inter-Zonal Congestion in real time, the ISO will make the minimum amount of adjustment necessary to relieve Inter-Zonal Congestion by incrementing or decrementing Generation or Demand, as necessary, based on the merit order stack, in accordance with Dispatch Protocol Section 8.3.~~

~~7.2.2 General Requirements for the ISO's Congestion Management**. The ISO's Congestion Management in the Day-Ahead Market and Hour-Ahead Market shall:**~~

~~**7.2.2.1** only operate if the Scheduling Coordinators do not eliminate Congestion voluntarily;~~

~~**7.2.2.2** adjust the Schedules submitted by Scheduling Coordinators only as necessary to alleviate Congestion;=~~

~~**7.2.2.3** maintain separation between the resource portfolios of different Scheduling Coordinators, by not arranging any trades between Scheduling Coordinators as part of the Inter-Zonal Congestion Management process;~~

~~**7.2.2.4** for Inter-Zonal Congestion Management, suggest, but not require, rescheduling within Scheduling Coordinators' portfolios of Schedules to produce a feasible Schedule by the conclusion of the scheduling procedure;~~

~~**7.2.2.5 [Not Used]**~~

~~**7.2.2.6** publish information and, if requested by Scheduling Coordinators will provide a mechanism to facilitate voluntary trades among Scheduling Coordinators;~~

~~**7.2.2.7 [Not Used]**~~

~~**7.2.2.8** adjust the Schedules submitted by Scheduling Coordinators on the basis of any price information voluntarily submitted through their Adjustment Bids; and~~

~~**7.2.2.9** for the hours when the ISO applies its Inter-Zonal Congestion Management apply the same Usage Charge to all Scheduling Coordinators for their allocated share of the Inter-Zonal Interface capacity.~~

~~7.2.3 Use of Computational Algorithms for Congestion Management and Pricing.~~

~~The ISO will use computer optimization algorithms to implement its Congestion Management process.~~

~~**7.2.4 Adjustment Bids Will Be Used by the ISO to Manage Congestion.**~~

~~**7.2.4.1 Uses of Adjustment Bids by the ISO.**~~

~~**7.2.4.1.1** The ISO shall use the Adjustment Bids, in both the Day-Ahead Market and the Hour-Ahead Market, to schedule Inter-Zonal Interface capacity to those Scheduling Coordinators which value it the most and to reflect the Scheduling Coordinators' implicit values for Inter-Zonal Interface capacity.~~

~~**7.2.4.1.2** The Adjustment Bids will be used by the ISO to determine the marginal value associated with each Congested Inter-Zonal Interface.~~

~~**7.2.4.1.3 [Not used]**~~

~~**7.2.4.1.4** The ISO shall also use the Adjustment Bids (in addition to other resources), in the ISO's real time system operation, for Intra-Zonal Congestion Management and to decrement Generation in order to accommodate Overgeneration conditions, including Reliability Must-Run Generation which the ISO requests under Reliability Must-Run Contracts.~~

~~**7.2.4.1.5** To facilitate trades amongst Scheduling Coordinators, the ISO will develop procedures to publish Adjustment Bids of those Scheduling Coordinators who authorize the publication of their identity and/or Adjustment Bids. Scheduling Coordinators will then be able to utilize this information to conduct trades to aid Congestion Management.~~

~~**7.2.4.2 Submission of Adjustment Bids.**~~

~~**7.2.4.2.1** Each Scheduling Coordinator is required to submit a preferred operating point for each of its resources. However, a Scheduling Coordinator is not required to submit an Adjustment Bid for a resource.~~

~~**7.2.4.2.2** The minimum MW output level specified for a resource, which may be zero MW, and the maximum MW output level specified for a resource must be physically realizable by the resource.~~

~~**7.2.4.2.3** The Scheduling Coordinator's preferred operating point for each resource must be within the range of the Adjustment Bids.~~

~~**7.2.4.2.4** Adjustment Bids can be revised by Scheduling Coordinators after the Day-Ahead Market has closed for consideration in the Hour-Ahead Market and, after the Hour-Ahead Market has closed, for consideration in the Real Time Market provided that, if the ISO has accepted all, or a portion of, an offered Adjustment Bid, the Scheduling Coordinator is obligated to provide the relevant capacity increase or decrease to the ISO at the price of the accepted Adjustment Bid.~~

~~**7.2.4.2.5** During the ISO's Day-Ahead scheduling process, the MW range of the Adjustment Bid, but not the price values, may be changed.~~

~~**7.2.4.2.6** An Adjustment Bid shall constitute a standing offer to the ISO until it is withdrawn.~~

~~**7.2.4.2.7** The ISO may impose additional restrictions and bidding activity rules on the form of Adjustment Bids, the updating of Adjustment Bids, and the Scheduling Coordinator that may submit Adjustment Bids in connection with Inter-SC Trades, as needed, to ensure that the ISO's computational algorithms can operate reliably and produce efficient outcomes.~~

~~7.2.5 Inter-Zonal Congestion Management.~~

~~**7.2.5.1** The scheduling procedures in the Day-Ahead Market and Hour-Ahead Market will first ascertain, through power flow calculations, whether or not Inter-Zonal Congestion would exist if all of the Preferred and Revised Schedules submitted by the Scheduling Coordinators were~~

~~accepted by the ISO. If no Inter-Zonal Congestion would exist, then all Inter-Zonal Interface uses will be accepted and the Usage Charges will be zero.~~

~~**7.2.5.2** The purpose of Inter-Zonal Congestion Management is to allocate the use of, and determine the marginal value of, active Inter-Zonal Interfaces. Inter-Zonal Congestion Management will comply with the requirements stated in Sections 7.2.2, 7.2.4 and 7.2.5.~~

~~**7.2.5.2.1** Inter-Zonal Congestion Management will keep each Scheduling Coordinator's portfolio of Generation and Demand (i.e., the Scheduling Coordinator's Preferred Schedule) separate from the portfolios of the other Scheduling Coordinators, as the ISO adjusts the Schedules to alleviate Inter-Zonal Congestion.~~

~~**7.2.5.2.2** If Congestion would exist on one or more active Inter-Zonal Interfaces, then the ISO shall execute its Inter-Zonal Congestion Management algorithms to determine a set of tentative (in the Day-Ahead procedure) allocations of Inter-Zonal Interface rights and tentative (in the Day-Ahead procedure) Usage Charges, where the Usage Charges will be calculated as the marginal values of the Congested Inter-Zonal Interfaces. The marginal value of a Congested Inter-Zonal Interface is calculated by the ISO's computer optimization algorithm to equal the total change in redispatch costs (based on the Adjustment Bids) that would result if the interface's scheduling limit was increased by a small increment.~~

~~**7.2.5.2.3** As part of the Day-Ahead scheduling procedure, but not the Hour-Ahead scheduling procedure, Scheduling Coordinators will be given the opportunity to adjust their Preferred Schedules (including the opportunity to make trades amongst one another) and to submit Revised Schedules to the ISO, in response to the ISO's Suggested Adjusted Schedules and prices for Inter-Zonal Interfaces.~~

~~**7.2.5.2.4** If the ISO receives any Revised Schedules it will execute its Inter-Zonal Congestion Management algorithms using revised Preferred Schedules, to produce a new set of allocations and prices.~~

~~**7.2.5.2.5** All of the ISO's calculations will treat each Settlement Period independently of the other Settlement Periods in the Trading Day.~~

~~**7.2.5.2.6 [Not Used]**~~

~~**7.2.5.2.7** If inadequate Adjustment Bids have been submitted to schedule Inter-Zonal Interface capacity on an economic basis and to the extent that scheduling decisions cannot be made on the basis of economic value, the ISO will allocate the available Inter-Zonal Interface capacity to Scheduling Coordinators in proportion to their respective proposed use of that capacity as indicated in their Schedules and shall curtail scheduled Generation and Demand to the extent necessary to ensure that each Scheduling Coordinator's Schedule remains balanced.~~

~~**7.2.5.2.8** The ISO will publish information prior to the Day-Ahead Market, between the iterations of the Day-Ahead Market, and prior to the Hour-Ahead Market, to assist the Scheduling Coordinators to construct their Adjustment Bids so as to actively participate in the management of Congestion and the valuation of Inter-Zonal Interfaces. This information may include the ISO's most-current information regarding: potentially Congested paths, projected transmission uses, projected hourly Loop Flows across Inter-Zonal Interfaces, scheduled line Outages, forecasts of expected system-wide Load, the ISO's Ancillary Services requirements, Generation Meter Multipliers, and power flow outputs.~~

~~**7.2.5.2.8** The ISO will also publish information, once it is available, regarding tentative prices for the use of Inter-Zonal Interfaces, and Generation shift factors for the use of Inter-Zonal~~

~~Interfaces, which indicate the relative effectiveness of Generation shifts in alleviating Congestion.~~

~~7.2.6 Intra-Zonal Congestion Management.~~

~~7.2.6.1 [Not used]~~

~~7.2.6.1.1 [Not used]~~

~~7.2.6.1.2 [Not Used]~~

~~7.2.6.1.3 [Not Used]~~

~~7.2.6.1.4 [Not Used]~~

~~7.2.6.1.5 [Not Used]~~

~~7.2.6.1.6 [Not Used]~~

~~7.2.6.2 Intra-Zonal Congestion During Initial Period.~~ ~~Except as provided in Sections 5.2 and 11.2.4.2, the ISO will perform Intra-Zonal Congestion Management in real time using available Adjustment Bids and Imbalance Energy bids, based on their effectiveness and in merit order, to minimize the cost of alleviating Congestion. In the event no Adjustment Bids or Imbalance Energy bids are available, the ISO will exercise its authority to direct the redispatch of resources as allowed under the Tariff, including Section 2.4.2 and 2.4.4.~~

~~7.2.6.3 Cost of Intra-Zonal Congestion Management.~~ ~~The net of the amounts paid by the ISO to the Scheduling Coordinators and the amounts charged to the Scheduling Coordinators will be calculated and charged to all Scheduling Coordinators through a Grid Operations Charge, as described in Section 7.3.2.~~

~~7.2.7 Creation, Modification and Elimination of Zones.~~

~~**7.2.7.1 Active Zones.** The Active Zones are as set forth in Appendix I to this ISO Tariff.~~

~~**7.2.7.2 Modifying Zones.** The ISO shall monitor usage of the ISO Controlled Grid to determine whether new Zones should be created, or whether existing Zones should be eliminated, in accordance with the following procedures.~~

~~**7.2.7.2.1** If over a 12-month period, the ISO finds that within a Zone the cost to alleviate the Congestion on a path is equivalent to at least 5 percent of the product of the rated capacity of the path and the weighted average High Voltage Access Charge and Low Voltage Access Charge, as applicable, of the Participating TOs, the ISO may announce its intention to create a new Zone. In making this calculation, the ISO will only consider periods of normal operations. A new Zone will become effective 90 days after the ISO Governing Board has determined that a new Zone is necessary.~~

~~**7.2.7.2.2** The ISO may, at its own discretion, shorten the 12-month and 90-day periods for creating new Zones if the ISO Governing Board determines that the planned addition of new Generation or Load would result in Congestion that would meet the criterion specified in Section 7.2.7.2.1.~~

~~**7.2.7.2.3 [Not Used]**~~

~~**7.2.7.2.4** If a new transmission project or other factors will eliminate Congestion between existing Zones, the ISO may modify or eliminate those Zones at its discretion.~~

~~**7.2.7.2.5** The ISO may change the criteria for establishing or modifying Zone boundaries, subject to regulatory approval by the FERC.~~

~~**7.2.7.3 Active and Inactive Zones.**~~

~~**7.2.7.3.1** An Active Zone is one for which a workably-competitive Generation market exists on both sides of the relevant Inter-Zonal Interface for a substantial portion of the year so that Congestion Management can be effectively used to manage Congestion on the relevant Inter-Zonal Interface. Pending the ISO's determination of the criteria for defining "workable competitive generation markets", the Inactive Zones will, as an interim measure, be those specified in Section 7.2.7.3.4.~~

~~**7.2.7.3.2** The Congestion Management described in this Section 7.2, and the Usage Charges stemming from the application of these procedures, shall not apply to Inter-Zonal Interfaces with Inactive Zones.~~

~~**7.2.7.3.3** For Inactive Zones, any costs associated with Congestion Management on the inactive Inter-Zonal Interface (for example, the above market costs associated with Generation "call" contracts) will be allocated to the Service Area of the Participating TOs who own the inactive Inter-Zonal Interface, as set forth in the TO Tariff and any Intra-Zonal Congestion Management costs within the Inactive Zone and the adjacent Zone will be combined and will be allocated as if the two Zones were a single Zone.~~

~~**7.2.7.3.4** The initial inactive Inter-Zonal Interfaces are the interface between the San Francisco Zone and the remainder of the ISO Controlled Grid, and the interface between the Humboldt Zone and the remainder of the ISO Controlled Grid. The initial Inactive Zones are the San Francisco Zone and the Humboldt Zone.~~

~~**7.2.7.3.5** The determination of whether a new Zone or an existing Inactive Zone should become an Active Zone and the determination of whether a workably-competitive Generation market exists for a substantial portion of the year, shall be made by the ISO Governing Board,~~

~~using the same approval criteria as are used for the creation or modification of Zones. The ISO Governing Board shall adopt criteria that defines a "workably competitive Generation" market. The ISO Governing Board will review the methodology used for the creation or modification of Zones (including Active Zones and Inactive Zones) on an annual basis and make such changes as it considers appropriate.~~

7.3 [Not Used]~~Usage Charges and Grid Operations Charges.~~

~~7.3.1 Usage Charges for Inter-Zonal Congestion.~~

~~The Usage Charge is used by the ISO to charge Scheduling Coordinators for the use of Congested Inter-Zonal Interfaces. Subject to Section 2.4.4.4.4.1, the Usage Charge shall be paid by all Scheduling Coordinators that use a Congested Inter-Zonal Interface. If a Scheduling Coordinator uses more than one Congested Inter-Zonal Interface, it will pay a Usage Charge for each Congested Inter-Zonal Interface that it uses.~~

~~**7.3.1.1 Calculation and Allocation of Usage Charge.** Those Scheduling Coordinators who are permitted by the ISO to use a Congested Inter-Zonal Interface will pay a Usage Charge. The Usage Charge is determined using Inter-Zonal Congestion Management described in Section 7.2.5, and is calculated as the hourly marginal value of an incremental kW of Inter-Zonal Interface capacity (in cents per kWh). The same Usage Charge will be used to compensate Scheduling Coordinators who, in effect, create transmission capacity through counter Schedules on Congested Inter-Zonal Interfaces.~~

~~**7.3.1.2 Calculation of Marginal Value of an Inter-Zonal Interface.** The marginal value of an Inter-Zonal Interface is the basis for the Usage Charge associated with the scheduled use of the Inter-Zonal Interface. This price is calculated from the Adjustment Bids of the Scheduling~~

~~Coordinators and the ISO's computer optimization algorithms, using the procedures described in Section 7.2.~~

~~**7.3.1.2.1** The price used to determine the Usage Charge will be the Day-Ahead price for those scheduling in the Day-Ahead Market, or the Hour-Ahead price for those Schedules submitted after the Day-Ahead Market closed.~~

~~**7.3.1.2.2** The Day-Ahead prices are calculated based on the Adjustment Bids of the Scheduling Coordinators who participate in the Day-Ahead Market. These Day-Ahead prices are used to calculate Usage Charges for Schedules accepted in the Day-Ahead Market.~~

~~**7.3.1.2.3** The Hour-Ahead prices are calculated based on Adjustment Bids submitted or otherwise still in effect after the Day-Ahead procedures have concluded. These prices are applied to all Schedules for the use of the Congested Inter-Zonal Interfaces that have been submitted and accepted after the ISO's Day-Ahead scheduling and Congestion Management have concluded.~~

~~**7.3.1.3 Default Usage Charge.** If inadequate or unusable Adjustment Bids have been submitted to the ISO to enable the ISO's Congestion Management to schedule Inter-Zonal Interface capacity on an economic basis, then the ISO will calculate and impose a default Usage Charge, in accordance with Sections 7.3.1.3.1 through 7.3.1.3.4.~~

~~**7.3.1.3.1** The default Usage Charge will be calculated within a range having an absolute floor of $0/MWh and an absolute ceiling of $500/MWh; provided that the ISO may vary the floor within the absolute limits, with day-prior notice (e.g., applicable to next day's Day-Ahead Market) to Scheduling Coordinators, and vary the ceiling within the absolute limits, with at least seven (7) days notice to Scheduling Coordinators.~~

~~**7.3.1.3.2** The default Usage Charge will be calculated, in accordance with this Section 7.3.1.3, by applying a pre-set adder, ranging from $0/MWh to $99/MWh, to the highest incremental Adjustment Bid used, less the applicable decremental Adjustment Bid used; provided that in all cases where there are insufficient decremental Adjustment Bids or no decremental Adjustment Bids available, in the exercise of mitigating Congestion, the applicable decremental price will be set equal to $0/MWh; provided, further, that the ISO may vary the pre-set adder with day-prior notice to Scheduling Coordinators (*e.g.*, applicable to next day's Day-Ahead Market).~~

~~**7.3.1.3.3** Upon the ISO Operations Date, and until such time as the ISO determines otherwise, the ceiling price for the default Usage Charge will be set at $250/MWh; the floor price for the default Usage Charge will be set at $30/MWh; and the pre-set adder that is to be applied in accordance with section 7.3.1.3.2 will be set at $0/MWh.~~

~~**7.3.1.3.4** The ISO will develop and implement a procedure for posting default Usage Charges on the WEnet or ISO Home Page.~~

~~**7.3.1.3.5** If the Congestion Management software is not capable of calculating the default Usage Charge upon the ISO Operations Date in accordance with Sections 7.3.1.3.1 through 7.3.1.3.4, the ISO will establish a fixed default Usage Charge within the absolute limits of $0/MWh and $500/MWh, which may be changed by the ISO with day-prior notice. Initially, the default Usage Charge would be capped at $100/MWh. As soon as tested and available, the ISO will implement the Congestion Management software to calculate the default Usage Charge in accordance with Sections 7.3.1.3.1 through 7.3.1.3.4 after giving at least seven (7) days notice to Scheduling Coordinators, by way of a notice posted on the ISO Internet "Home Page" at http://www.caiso.com or such other Internet address as the ISO may publish from time to time.~~

~~**7.3.1.4 Determination of Usage Charges to be Paid by Scheduling Coordinator.** All Scheduling Coordinators whose Schedules requiring use of a Congested Inter-Zonal Interface have been accepted by the ISO, shall pay a Usage Charge for each hour for which they have been scheduled to use the Inter-Zonal Interface. The amount payable shall be the product of the Usage Charge referred to in Section 7.3.1.2 for the particular hour, multiplied by the Scheduling Coordinator's scheduled flows (in kW) and capacity, if any, reserved for Ancillary Services over the Inter-Zonal Interface for that particular hour.~~

~~**7.3.1.5 Determination of Usage Charges to be Paid to Scheduling Coordinators Who Counter-Schedule.**~~

~~**7.3.1.5.1** Scheduling Coordinators who in effect create additional Inter-Zonal Interface transmission capacity on Congested Inter-Zonal Interfaces will receive from the ISO a Usage Charge for each hour they have counter-scheduled on the Congested Inter-Zonal Interfaces. The amount payable shall be the product of the Usage Charge referred to in Section 7.3.1.2 for that particular hour, multiplied by the Scheduling Coordinator's scheduled flows.~~

~~**7.3.1.5.2** If a Scheduling Coordinator fails to provide the scheduled flows in a counter direction, it must reimburse the ISO for the ISO's costs of buying or selling Imbalance Energy in each of the Zones affected by the non-provided scheduled flows in a counter direction, at the ISO's Zonal Imbalance Energy prices. That is, for any Scheduling Coordinator that does not produce, in real time, the amount of Energy scheduled in the Day-Ahead Market or Hour-Ahead Market will be deemed to have purchased/sold the amount of Energy under/over produced in the real time imbalance market at the real time price.~~

~~**7.3.1.6 ISO Disbursement of Net Usage Charge Revenues.** The ISO will determine the net Usage Charges on an interface-by-interface basis by subtracting the Usage Charge fees paid to~~

~~Scheduling Coordinators from the Usage Charge fees paid by Scheduling Coordinators. The net Usage Charge revenues collected by the ISO for each Inter-Zonal Interface shall be, subject to the provisions of Section 7.3.1.7 of the ISO Tariff, paid to: (i) FTR Holders, in accordance with Section 9.6; and (ii) to the extent not paid to FTR Holders, to Participating TOs who own the Inter-Zonal Interfaces (to be credited in turn by them to their Transmission Revenue Balancing Accounts, or, for those Participating TOs that do not have such accounts, to their transmission revenue requirements).~~

~~**7.3.1.7 ISO Debit of Net Usage Charge Revenues.** If, after the issuance of Final Day-Ahead Schedules by the ISO, (a) Participating TOs instruct the ISO to reduce interface limits based on operating conditions or (b) an unscheduled transmission outage occurs and as a result of either of those events, Congestion is increased and Available Transfer Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the ISO shall: (1) charge each Participating TO and FTR Holder with an amount equal to its proportionate share, based on its financial entitlement to Usage Charges in the Day-Ahead Market in accordance with Section 7.3.1.6, of the product of (i) the Usage Charge in the Day-Ahead Market and (ii) the reduction in Available Transfer Capacity across the Inter-Zonal Interface in the direction of the Congestion (such amount due to the Participating TOs to be debited by them in turn from their Transmission Revenue Balancing Accounts or, for those Participating TOs that do not have such accounts, to their transmission revenue requirements); (2) charge each Scheduling Coordinator with its proportionate share, based on Schedules in the Day-Ahead Market across the Inter-Zonal Interface in the direction of the Congestion, of the difference between the amount charged to Participating TOs and FTR Holders under clause (1) and the Usage Charges in the Hour-Ahead Market associated with the reduced Available Transfer Capacity across the Congested Inter-Zonal Interface; and (3) credit each Scheduling Coordinator whose Schedule in the Hour-Ahead~~

~~Market for the transfer of Energy across the Congested Inter-Zonal Interface was adjusted due to the reduction in Available Transfer Capacity an amount equal to the product of the adjustment (in MW) and the Usage Charge in the Hour-Ahead Market (in$/MW).~~

~~The ISO will issue a notice to Scheduling Coordinators of the operating hour, and extent, for which the derate will apply in the relevant Hour-Ahead Markets. The timing and form of such notices shall be set forth in ISO procedures.~~

~~7.3.2 Grid Operations Charge for Intra-Zonal Congestion.~~

~~Scheduling Coordinators whose resources are redispatched by the ISO, in accordance with Intra-Zonal Congestion Management, will be paid or charged based on the Adjustment Bids or Imbalance Energy bids that they have provided to the ISO. The net redispatch cost will be recovered for each Settlement Period through the Grid Operations Charge, which shall be paid to the ISO by all Scheduling Coordinators in proportion to their metered Demands within the Zone with Intra-Zonal Congestion, and scheduled exports from the Zone with Intra-Zonal Congestion to a neighboring Control Area, provided that, with respect to Demands within an MSS in the Zone and scheduled exports from the MSS to a neighboring Control Area, a Scheduling Coordinator shall be required to pay Grid Operations Charges only with respect to Intra-Zonal Congestion, if any, that occurs on an interconnection between the MSS and the ISO Controlled Grid, and with respect to Intra-Zonal Congestion that occurs within the MSS, to the extent the Congestion is not relieved by the MSS Operator.~~

7.4 [Not Used]~~Transmission Losses.~~

~~7.4.1 Obligation to Provide for Transmission Losses.~~

~~Each Scheduling Coordinator shall ensure that it schedules sufficient Generation to meet both its Demand and Transmission Losses responsibilities as determined in accordance with this Section 7.4.~~

~~7.4.2 Determination of Transmission Losses.~~

~~The total Demand that may be served by a Generating Unit, in a given hour, taking account of Transmission Losses, is equal to the product of the total Metered Quantity of that Generating Unit in that hour and the Ex Post Generation Meter Multiplier calculated by the ISO in the hour for that Generator location except in accordance with Section 7.4.3. The Ex Post Generation Meter Multiplier shall be greater than one (1) where the Generating Unit's contribution to the ISO Controlled Grid reduces Transmission Losses and shall be less than one (1) where the Generating Unit's contribution to the system increases Transmission Losses. All Generating Units supplying Energy to the ISO Controlled Grid at the same electrical bus shall be assigned the same Ex Post Generation Meter Multiplier.~~

~~7.4.2.1 Procedures for Calculating Generation Meter Multiplier.~~

~~7.4.2.1.1~~ ~~By 6:00 p.m. two days preceding a Trading Day, the ISO will calculate, and post on WEnet, an estimated Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. The Generation Meter Multipliers shall be determined utilizing the Power Flow Model based upon the ISO's forecasts of total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO shall continuously update the data to be used in calculating the Generation Meter Multipliers to reflect changes in system conditions on the ISO Controlled Grid, and the ISO shall provide all Scheduling Coordinators with access to such data. The ISO shall~~

~~not be required to determine new Generation Meter Multipliers for each hour; the ISO will determine the appropriate period for which each set of Generation Meter Multipliers will apply, which period may vary based upon the expected frequency and magnitude of changes in system conditions on the ISO Controlled Grid.~~

~~**7.4.2.1.2** The ISO will calculate the Ex Post Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. The Ex Post Generation Meter Multipliers shall be determined utilizing the Power Flow Model based upon the ISO's total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO's total Demand shall be determined using real time power flow data based on a state-estimation result.~~

~~**7.4.2.2 Methodology for Calculating Generation Meter Multiplier.** The ISO shall calculate the Generation Meter Multiplier for each Generating Unit location in a given hour by subtracting the Scaled Marginal Loss Rate from 1.0.~~

~~**7.4.2.2.1** The Scaled Marginal Loss Rate for a given Generating Unit location in a given hour shall equal the product of (i) the Full Marginal Loss Rate for each Generating Unit location and hour, and (ii) the Loss Scale Factor for such hour.~~

~~**7.4.2.2.2** The ISO shall calculate the Full Marginal Loss Rate for each Generating Unit location for an hour by utilizing the Power Flow Model to calculate the effect on total Transmission Losses for the ISO Controlled Grid of injecting an increment of Generation at each such Generating Unit location to serve an equivalent incremental MW of Demand distributed on a pro-rata basis throughout the ISO Controlled Grid.~~

~~**7.4.2.2.3** The ISO shall determine the Loss Scale Factor for an hour by determining the ratio of forecast Transmission Losses to the total Transmission Losses which would be collected if Full Marginal Loss Rates were applied to each Generating Unit in that hour.~~

~~7.4.3 **In the event that the Power Flow Model fails to determine Ex Post GMMs, for example if GMMs are outside the range of reasonability (typically 0.8 to 1.1), the ISO will use Default GMMs in their place.**~~

7.5 FERC Annual Charges.

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8. **GRID MANAGEMENT CHARGE.**

* * *

8.3.3 ~~The Market Operations~~ Ancillary Services and Real-Time Energy Operations Charge.

The Ancillary Services and Real-Time Energy Operations Charge for each Scheduling Coordinator or Other Appropriate Party is calculated as the product of the rate for the Ancillary Services and Real-Time Energy Operations Charge and the Scheduling Coordinator's or Other Appropriate Party's total purchases and sales (including out-of-market transactions) of Ancillary Services (including the capacity selected by the ISO in the Residual Unit Commitment Process for which an SC receives a capacity payment), Real-Time Energy, and Imbalance Energy (both instructed and uninstructed), plus 50% of effective self-provision of Ancillary Services. The rate for the Ancillary Services and Real-Time Energy Operations Charge is determined by dividing the GMC costs allocated to this service category by the total purchases and sales of Ancillary Services plus the total RUC Capacity, Real-time Energy and Imbalance Energy (both instructed and uninstructed) and 50% of effective self-provision of Ancillary Services according to the formula in Appendix F, Schedule 1, Part A of this Tariff. Energy procured to cover line

losses or other transmission losses also shall be assessed this charge. ~~The Market Operations Charge for each Scheduling Coordinator is calculated as the product of the rate for the Market Operations Charge and the Scheduling Coordinator's total purchases and sales of Ancillary Services, Supplemental Energy, and Imbalance Energy (both instructed and uninstructed). The rate for the Market Operations Charge is determined by dividing the GMC costs allocated to this service category by the total purchases and sales of Ancillary Services, Supplemental Energy and Imbalance Energy (both instructed and uninstructed) according to the formula in Schedule 1 of this Tariff.~~

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9. FIRM TRANSMISSION RIGHTS

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10. METERING.

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10.2.2 Duty to Install and Maintain Meters.

The ISO may require ISO Metered Entities to install, at their cost, additional meters and relevant metering system components, including real time metering, at ISO specified Meter Points or other locations as deemed necessary by the ISO, in addition to those connected to or existing on the ISO Controlled Grid at the ISO Operations Date, including requiring the metering of transmission interfaces **between UDCs and the ISO Control Area and other Control Areas**. ~~connecting Zones.~~ ISO Metered Entities, at their cost, shall install and maintain, or cause to be installed and maintained, metering equipment and associated communication devices at ISO designated Meter Points to meet the requirements of this Section 10 and the ISO metering protocols. Nothing in this Section 10 shall preclude ISO Metered Entities from installing additional meters, instrument transformers and associated communications facilities at their own cost.

* * *

10.3 Meter Service Agreements for ISO Metered Entities.

10.3.1 Requirement for Meter Service Agreements.

The ISO shall establish meter service agreements with ISO Metered Entities for the collection of Meter Data. Such agreements shall specify that ISO Metered Entities shall make available to the ISO's revenue meter data acquisition and processing system, Meter Data meeting the requirements of these Sections 10.1 to 10.5 inclusive and the ISO metering protocols. The meter service agreement and the ISO metering protocols shall specify the format of Meter Data to be submitted, which shall be identified by TO, Distribution System, ~~Zone~~ **Location**, ISO Controlled Grid interface point and other information reasonably required by the ISO. Meter service agreements will identify other authorized users which are allowed to access the Settlement Quality Meter Data held by the ISO. The ISO will ensure that the relevant UDCs and TOs are included as other authorized users.

* * *

11. ISO SETTLEMENTS AND BILLING.

* * *

11.1.6 The ISO shall settle the following charges in accordance with Section 11.2 of this ISO Tariff:

(1) Grid Management Charge;

~~(2) Grid Operations Charge;~~

(2~~3~~) Ancillary Services charges;

(**3**~~4~~) Imbalance Energy charges;

(**4**~~5~~) Usage Charges;

(**5**~~6~~) High Voltage Access Charges and Transition Charges;

(**6**~~7~~) Wheeling Access Charges;

(**7**~~8~~) Voltage Support and Black Start charges; and

(**8**~~9~~) Reliability Must-Run Charges

11.2 Calculations of Settlements.

The ISO shall calculate, account for and settle the following charges in accordance with this ISO Tariff.

11.2.1 Grid Management Charge.

The Grid Management Charge will be levied in accordance with Section 8 of this ISO Tariff.

11.2.2 [Not Used] ~~Grid Operations Charge.~~

~~The Grid Operations Charge will be levied in accordance with Section 7.3.2 of this ISO Tariff.~~

11.2.3 Ancillary Services

The ISO shall calculate, account for and settle charges and payments for Ancillary Services as set out in the **Settlement and Billing Protocol Appendix C**.~~Sections 2.5.27.1 to 4, and 2.5.28.1 to 4 of this ISO Tariff.~~

11.2.4 Imbalance Energy.

The ISO shall calculate, account for and settle Imbalance Energy in the Real Time Market for each **Dispatch Interval** ~~BEEP Interval Period~~ for the relevant **Location**~~Zone or Scheduling Point~~ within the ISO Controlled Grid. Imbalance Energy is the difference between the Metered Quantity and the Energy that corresponds to the final Hour-Ahead Schedule. Instructed Imbalance Energy is the portion of Imbalance Energy that is produced or consumed due to Dispatch **I**~~i~~nstructions. The Instructed Imbalance Energy will be calculated based on all Dispatch **I**~~i~~nstructions taking into account applicable ramp rates and time delays. All Dispatch **I**~~i~~nstructions shall be deemed delivered. The remaining Imbalance Energy constitutes Uninstructed Imbalance Energy, and will be calculated based on the difference between the Metered Quantity and the Generator's Dispatched Operating Point.

11.2.4.1 Net Settlements for Uninstructed Imbalance Energy.

Uninstructed Imbalance Energy attributable to each Scheduling Coordinator for each Settlement Period in the relevant **Location**~~Zone~~ shall be deemed to be sold or purchased, as the case may be, by the ISO and charges or payments for Uninstructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each **Dispatch**~~BEEP~~ Interval in accordance with **Section 31.4.3.4.2 and the Settlement and Billing Protocol Appendix D**~~Section 2.5.23.2.1~~.

11.2.4.1.1 Settlement for Instructed Imbalance Energy

Instructed Imbalance Energy attributable to each Scheduling Coordinator in each **Dispatch**~~BEEP~~ Interval shall be deemed to be sold or purchased, as the case ay be, by the ISO and charges or payments for Instructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each **Dispatch**~~BEEP~~ Interval in accordance with **Section 31.4.3.4.1 and the Settlement and Billing Protocol Appendix D**~~Section 2.5.23~~.

11.2.4.1.2 Penalties for Uninstructed Imbalance Energy

The ISO shall charge Scheduling Coordinators Uninstructed Deviation Penalties for Uninstructed Imbalance Energy resulting from resource deviations outside a tolerance band from their dispatched operating point, for dispatched resources, or their final Hour-Ahead Schedule otherwise. The Dispatched Operating Point will take into account the expected ramping of a resource as it moves to a new Hour-Ahead Schedule at the top of each hour and as it responds to Dispatch **I**~~i~~nstructions. The Uninstructed Deviation Penalty will be applied as follows:

a) The Uninstructed Deviation Penalty will be calculated and assessed for in each ~~BEEP Interval~~**Dispatch Interval**. ~~in hours that Section 5.6.3 is in effect; the ISO has not declared a Staged System Emergency; or parts of hours except when Section 5.6.3 is in effect;~~

b) The Uninstructed Deviation Penalty will not be assessed for positive Uninstructed Imbalance Energy in hours in which the ISO has declared a System Emergency;

c~~b~~) The Uninstructed Deviation Penalty will apply to Interconnection Schedules if a pre-**D**~~d~~ispatch **I**~~i~~nstruction is declined or not delivered. ~~However, uninstructed energy resulting from declining intra-hour Instructions will not be subject to Uninstructed Deviation Penalty.~~ Dynamic Interconnection Schedules, to the extent they deviate without instruction from their final Hour-Ahead Schedule, and real-time instructions for Energy from Interconnection Schedule bids that are declined, will be subject to the Uninstructed Deviation Penalty;

d~~c~~) The Uninstructed Deviation Penalty will not apply to Load, other than **Dispatchable**~~Participating~~ Load; for **Dispatchable**~~Participating~~ Load, the Uninstructed Deviation Penalty will not apply for the duration of the relevant Minimum Down Time;

e~~d~~) The Uninstructed Deviation Penalty will not apply to constrained resources for the duration of the relevant ~~startup~~start-up/shutdown and Minimum Up/Down Times;

f~~e~~) The Uninstructed Deviation Penalty will not apply to Regulatory Must-Run Generation or Participating Intermittent Resources that meet the scheduling obligations established in the technical standards for Participating Iintermittent Resources adopted by the ISO and published on the ISO Home Page or Regulatory Must-Run Generation. No other applicable charges will be affected by this exemption. Uninstructed Deviation Penalty also will not apply to Qualifying Facilities that have not executed a Participating Generator Agreement (PGA), pending resolution of QF-PGA issues at the Commission;

g~~f~~) For Metered Subsystems (MSS), the Uninstructed Deviation Penalty will apply to the net injection (System Unit generation plus import minus MSS load and export) into the ISO Controlled Grid;

h~~g~~) The Uninstructed Deviation Penalty will not apply to Generators providing Regulation to the extent that the Generators' Uninstructed Deviations are within the range of their actual Regulation range;

i~~h~~) The Uninstructed Deviation Penalty will be calculated and assessed for each resource separately, however, resources represented by the same Scheduling Coordinator and connected to the same ISO Controlled Grid bus and voltage level can be aggregated for purposes of Uninstructed Deviation Penalty determination. Other levels of aggregation for purposes of the Uninstructed Deviation Penalty will be considered on a case-by-case basis based on an ISO review of impact on the ISO Controlled Grid;

j~~i~~) The tolerance band for the application of the Uninstructed Deviation Penalties to Generators or aggregated Generators initially will be the Energy produced in a ~~BEEP Interval~~**Dispatch Interval** by the greater of five (5) MW or three percent (3%) of the relevant generating unit's maximum output (P_{max}), as registered in the Master File;

k~~j~~) The tolerance band for the application of the Uninstructed Deviation Penalties to **Dispatchable**~~Participating~~ Loads initially will be equal to the Energy produced in a ~~BEEP Interval~~**Dispatch Interval** by the greater of five (5) MW or three percent (3%) of the relevant final Hour-Ahead Schedule;

l~~k~~) The Uninstructed Deviation Penalty will not apply when the ~~BEEP Interval~~**Dispatch Interval Locational Marginal Price** ~~Ex Post Price~~ is negative or zero;

l~~m~~) The Uninstructed Deviation Penalty for positive Uninstructed Imbalance Energy will be the amount of the Uninstructed Imbalance Energy in excess of the tolerance band multiplied by a price that initially will be equal to 100% of the corresponding ~~BEEP Interval~~**Dispatch Interval Locational Marginal Price** ~~Ex Post Price~~; and the net effect of the Uninstructed Deviation Penalty and the Settlement for positive Uninstructed Imbalance Energy beyond the tolerance band will be that the ISO will not pay for such Energy;

n~~m~~) The Uninstructed Deviation Penalty for negative Uninstructed Imbalance Energy will be the amount of the Uninstructed Imbalance Energy in excess of the tolerance band multiplied by a price that initially will be initially equal to 25% of the corresponding ~~BEEP Interval~~**Dispatch Interval Locational Marginal Price** ~~Ex Post Price~~; and the net effect of the Uninstructed Deviation Penalty and Uninstructed Imbalance Energy settlement initially will be that any such Energy will be charged at 125% of the corresponding ~~Dispatch Interval~~ **Locational Marginal Price** ~~Ex Post Price~~;

o~~n~~) The Uninstructed Deviation Penalty will not apply to deviations from Energy delivered as part of a scheduled test so long as the test has been scheduled by the Scheduling Coordinator with the ISO or the ISO has initiated as test for the purposes of validating unit performance;

p~~o~~) The Uninstructed Deviation Penalty will apply to **Exceptional Dispatches**~~Out of Market (OOM) transactions~~;

~~p)~~**p**~~q~~) Generating Units, **Dispatchable Load**~~Curtailable Demands~~ ~~Curtailable Demand~~ and dispatchable Interconnection resources with negative Uninstructed Imbalance Energy will be exempted from the Uninstructed Deviation Penalty if the Generating Unit, **Dispatchable Load**~~Curtailable Demand~~ ~~Curtailable Demand~~ or dispatchable Interconnection resource was physically incapable of delivering the expected Energy, provided that the Generating Unit, **Dispatchable Load** ~~Curtailable Demand~~~~Curtailable Demand~~ or dispatchable Interconnection resource had notified the ISO within 30 minutes of the onset of an event that prevents the resource from performing its obligations. A Generating Unit, **Dispatchable Load** ~~Curtailable Demand~~~~Curtailable Demand~~ or dispatchable Interconnection resource must notify ISO operations staff of its reasons for failing to deliver the expected Energy in accordance with Section 2.3.3.9.2 and must provide information to the ISO that verifies the reason the resource failed to comply with the ~~Dispatch instruction~~Dispatch **I**~~i~~nstruction within 72 hours of the operating hour in which the instruction is issued; and

~~q)~~**q**~~r~~) Operational adjustments associated **with** interchange schedules making use of E~~e~~xisting C~~c~~ontract rights shall not be subject to the **U**~~u~~uninstructed **D**~~d~~deviation **P**~~p~~penalty.

Amounts collected as Uninstructed Deviation Penalties shall first be assigned to reduce the portion of Residual Unit Commitment costs that would otherwise be included in Total Excess Hourly Unit Commitment Cost, pursuant to Section **5.12**.8.3. Any remaining amounts of collected Uninstructed Deviation Penalties shall next be assigned to reduce the portion of above-MCP costs that would otherwise be assigned pro rata to all Scheduling Coordinators in that ~~BEEP Interval~~**Dispatch Interval** pursuant to Section 11.2.4.2.2. Any remaining portion of amounts collected as Uninstructed Deviation Penalties after satisfying these sequential commitments shall be treated in accordance with SABP 6.5.2.

11.2.4.2 ~~[Not Used]~~ Payment Options for ISO Dispatch Orders

With respect to all resources with no bids (either submitted or inserted by the ISO) in ~~which have not bid into~~ the Imbalance Energy or Ancillary Services markets but which have been dispatched by the ISO to avoid an intervention in market operations, to prevent or relieve a System Emergency, or to satisfy a locational requirement, the ISO shall calculate, account for and, if applicable, settle deviations from the Final Hour-Ahead Schedule ~~submitted on behalf of each such resource~~, with the relevant Scheduling Coordinator for each Settlement Period for each such resource by application of either of the following payment options described below. For resources subject to a Reliability Must-Run Contract, the ISO will dispatch such resources according to the terms of the RMR Contract. In circumstances where an RMR Unit would be used to resolve ~~Intra-Zonal~~ Congestion and there are no such RMR Units available, a resource may be called upon and paid under this Section to resolve the ~~Intra-Zonal~~ Congestion.

By December 31 of each year for the following calendar year, each Scheduling Coordinator for a resource shall select one of the following payment options for each resource it schedules:

(a) the Hourly Ex Post Price~~Uninstructed Imbalance Energy Charge price~~ as calculated in accordance with SABP Appendix D~~Section 11.2.4.1 (i.e., using the Hourly Ex Post Price)~~ or

(b) a calculated price:

(i) for decremental dispatch orders that is an Energy payment to the ISO that is equal to the Locational Marginal Price~~Market Clearing Price~~ for the relevant Dispatch Interval~~Settlement Period for the applicable Energy market~~ less verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's D~~d~~ispatch I~~i~~nstruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and

(ii) for incremental dispatch orders is the sum of: 1) a capacity payment equal to the average Day-Ahead ~~Market~~ Ancillary Service Marginal Prices~~prices~~ for Spinning Reserve and Non-Spinning Reserve for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 2) an Energy payment equal to the average calculated using the ~~PX~~ Day-Ahead, ~~PX~~ Hour-Ahead and ~~ISO~~ Real-Time Locational Marginal Prices~~Market Energy prices~~ for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 3) such resource's verifiable start-up fuel costs, if the start-up was solely attributable to the ISO's dispatch instruction and if the Scheduling Coordinator provides the resource's start-up fuel costs to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and 4) verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's D~~d~~ispatch I~~i~~nstruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the

Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched. References to "similar days" in this Section refer to Business Days when the resource is dispatched on a Business Day and otherwise to days that are not Business Days.

To the extent a Scheduling Coordinator does not specify a payment option, the ISO will apply the payment provisions of payment option (a)~~Section 11.2.4.1~~.

11.2.4.2.1 [Not Used] ~~Allocation of Costs Resulting From Dispatch Instructions~~

~~Pursuant to Section 11.2.4.1, the ISO may, at its discretion, Dispatch any Participating Generator, Participating Load and dispatchable Interconnection resource that has not bid into the Imbalance Energy or Ancillary Services markets, to avoid an intervention in market operations or to prevent or relieve a System Emergency. Such Dispatch may result from, among other things, planned and unplanned transmission facility outages; bid insufficiency in the Ancillary Services and Real-Time Energy markets; and location-specific requirements of the ISO. The cost associated with each Dispatch instruction is broken into two components:~~

~~a) the portion of the Energy payment at or below the Market Clearing Price (“MCP”) for the BEEP Interval, and~~

~~b) the portion of the Energy payment above the MCP, if any, for the BEEP Interval.~~

~~For each BEEP Interval, costs above the MCP incurred by the ISO for such Dispatch instructions necessary as a result of a transmission facility outage or in order to satisfy a location-specific requirement in that BEEP Interval shall be payable to the ISO by the Participating Transmission Owner in whose Service Area the transmission facility is located or the location-specific requirement arose. The costs incurred by the ISO for such Dispatch instructions for reasons other than for a transmission facility~~

~~outage or a location-specific requirement will be recovered in the same way as for Instructed Imbalance energy.~~

11.2.4.2.2 Allocation of Above-MCP Costs

For each ~~BEEP Interval~~**Dispatch Interval**, the above-MCP costs incurred by the ISO as a result of Instructed Imbalance Energy and Dispatch **I**~~i~~structions for reasons other than for a transmission facility outage or a location-specific requirement shall be charged to Scheduling Coordinators as follows. Each Scheduling Coordinator's charge shall be the lesser of:

(a) the pro rata share of the total above-MCP costs based upon the ratio of each Scheduling Coordinator's Net Negative Uninstructed Deviations to the total System Net Negative Uninstructed Deviations; or

(b) the amount obtained by multiplying the Scheduling Coordinator's Net Negative Uninstructed Deviation for each ~~BEEP Interval~~**Dispatch Interval** and a weighted average price. The weighted average price is equal to the total above-MCP costs divided by the MWh delivered as a result of ISO instructions with a cost component above the MCP.

The difference between ISO charges to Scheduling Coordinators with Net Negative Uninstructed Deviations and the total above-MCP costs incurred by the ISO due to Instructed Imbalance Energy and Dispatch **I**~~i~~structions for reasons other than for a transmission facility outage or a location-specific requirement, as such difference is reduced pursuant to Section 11.2.4.1.2, shall be allocated amongst all Scheduling Coordinators in that ~~BEEP Interval~~**Dispatch Interval** pro rata based on their metered Demand, including Exports.

The Scheduling Coordinator shall be exempt from the allocation of above-MCP costs in a **Dispatch Interval** ~~BEEP interval~~ **i**f the Scheduling Coordinator has sufficient incremental Energy bids from physically available resources in the Imbalance Energy market to cover the net negative Uninstructed Deviation in the given interval of a resource and the prices of these Energy bids do not exceed the applicable **Bid Ceiling**~~NECPL~~.

11.2.4.3 Unaccounted For Energy (UFE)

For settlement purposes, UFE is treated as Imbalance Energy. For each ~~BEEP Interval~~**Dispatch Interval**, the ISO will calculate UFE on the ISO Controlled Grid, for each UDC Service Area. The UFE will be settled as Imbalance Energy at the ~~BEEP Interval~~**Dispatch Interval Locational Marginal Price** ~~Ex Post Price~~. UFE attributable to meter measurement errors, load profile errors, Energy theft, and distribution loss deviations will be allocated to each Scheduling Coordinator based on the ratio of their metered Demand (including exports to neighboring Control Areas) within the relevant UDC Service Area to total metered Demand within the UDC Service Area.

11.2.4.4 High Voltage Access Charges and Transition Charges will be levied in accordance with Section 7.1 of this ISO Tariff and Appendix F, Schedule 3.

11.2.4.5 Participating Intermittent Resources

11.2.4.5.1 Uninstructed Energy by Participating Intermittent Resources

Uninstructed Imbalance Energy associated with deviations by a Participating Intermittent Resource shall be settled as provided in this Section 11.2.4.5.1 for every Settlement Period in which such Participating Intermittent Resource meets the scheduling requirements established in the technical standards for Participating Intermittent Resources adopted by the ISO and published on the ISO Home Page. In each Settlement Period such requirements are met, the Participating Intermittent Resource shall be exempt from the charges (payments) for Uninstructed Imbalance Energy. Instead, the net Uninstructed Imbalance Energy in each ~~BEEP Interval~~**Dispatch Interval** shall be assigned to a deviation account specific to each Participating Intermittent Resource. The net balance in each deviation account at the end of each calendar month shall be paid (or charged) to the Scheduling Coordinator for the associated Participating Intermittent Resource at the average price specified in **Settlement and Billing Protocol Appendix D**~~Section 2.5.23.2.3 of the ISO Tariff~~. If the above- referenced scheduling requirements for Participating Intermittent Resources are not met, then charges (payments) for Uninstructed Imbalance Energy during such Settlement Periods shall be determined in accordance with Section 11.2.4.1.

11.2.4.5.2 Adjustment of Other Charges Related to Participating Intermittent Resources

Charges pursuant to ~~Section 2.5.28.4 or~~ Section 11.2.4.2.2 to Scheduling Coordinators representing Participating Intermittent Resources shall exclude the effect of uninstructed deviations by Participating Intermittent Resources that have scheduled in accordance with the technical standards for Participating Intermittent Resources adopted by the ISO and published on the ISO Home Page. The amount of such adjustments shall be accumulated and settled as provided in Section 11.2.4.5.3.

11.2.4.5.3 Allocation of Costs From Participating Intermittent Resources

The charges (payments) for Uninstructed Imbalance Energy that would have been calculated if the ~~BEEP Interval~~**Dispatch Interval** deviations by each Participating Intermittent Resource were priced at the appropriate ~~BEEP Interval~~**Dispatch Interval Locational Marginal Price** ~~Ex Post Price~~ specified in **Settlement and Billing Protocol Appendix D**~~Section 2.5.23.2.1~~ shall be assigned to a monthly balancing account for all Participating Intermittent Resources in the ISO Control Area. The balance in such account at the end of each month shall be netted against the aggregate payments (charges) by Scheduling Coordinators on behalf of Participating Intermittent Resources pursuant to Section 11.2.4.5.1. The resulting balance, together with the adjustments to charges in each ~~BEEP Interval~~**Dispatch Interval** or Settlement Period pursuant to Section 11.2.4.5.2 shall be assigned to each Scheduling Coordinator in the same proportion that such Scheduling Coordinator's aggregate Net Negative Uninstructed Deviations in that month bears to the aggregate Net Negative Uninstructed Deviations for all Scheduling Coordinators in the Control Area in that month.

11.2.4.5.4 Payment of Forecasting Fee

A fee to defray the costs of the implementation of the technical standards for Participating Intermittent Resources shall be assessed to Scheduling Coordinators for Participating Intermittent Resources as specified in Schedule 4 of Appendix F.

11.2.4.6 [Not Used]

11.2.5 [Not Used]~~Usage Charges.~~

~~Usage Charges will be levied in accordance with Section 7.3.1 of this Tariff.~~

11.2.6 Wheeling Through and Wheeling Out Transactions.

The ISO shall calculate, account for and settle charges and payments for Wheeling Through and Wheeling Out transactions in accordance with Section 7.1.4 of this Tariff.

11.2.7 Voltage Support and Black Start Charges.

The ISO shall calculate, account for and settle charges and payments for Voltage Support and Black Start as set out in **Settlement and Billing Protocol Appendix G**~~Sections 2.5.27.5, 2.5.27.6, 2.5.28.5 and 2.5.28.6 of this ISO Tariff~~.

11.2.8 Reliability Must-Run Charges

The ISO shall calculate and levy the charges for Reliability Must-Run Contract costs in accordance with Section 5.2.7 of this ISO Tariff.

11.2.9 Neutrality Adjustments

The ISO shall be authorized to levy additional charges or payments as special adjustments in regard to:

(a) amounts required to round up any invoice amount expressed in dollars and cents to the nearest whole dollar amount in order to clear the ISO Clearing Account. These charges will be allocated amongst Scheduling Coordinators over an interval determined by the ISO and pro rata based on metered Demand (including exports) during that interval;

(b) amounts in regard to penalties which may be levied by the ISO in accordance with the ISO Tariff. These charges will be levied on the Market Participants liable for payment of the penalty;

(c) amounts required to reach an accounting trial balance of zero in the course of the Settlement process in the event that the charges calculated as due from ISO Debtors are lower than payments calculated as due to the ISO Creditors for the same Trading Day. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day. In the event that the charges due from ISO Debtors are higher than the payments due to ISO Creditors, the ISO shall allocate a payment to the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day;

(d) amounts required with respect to payment adjustments for regulating Energy as calculated in accordance with **Settlement and Billing Protocol Appendix C**~~Section 2.5.27.1~~. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (excluding exports) in MWh for that Trading Day; and

(e) awards payable by or to the ISO pursuant to good faith negotiations or ISO ADR Procedures that the ISO is not able to allocate to or to collect from a Market Participant or Market Participants in accordance with Section 13.5.3. These charges will be allocated amongst Scheduling Coordinators over an interval determined by the ISO and pro rata based on metered Demand (including exports) during that interval.

11.2.9.1 The total annual charges levied under Section 11.2.9 shall not exceed $0.095/MWh, applied to Gross Loads in the ISO Control Area and total exports from the ISO Controlled Grid, unless: (a) the ISO Governing Board reviews the basis for the charges above that level and approves the collection of charges above that level for a defined period; and (b) the ISO provides at least seven days' advance notice to Scheduling Coordinators of the determination of the ISO Governing Board.

11.2.10 Payments Under Section 2.3.5.1 Contracts

The ISO shall calculate and levy charges for the recovery of costs incurred under contracts entered into by the ISO under the authority granted in Section 2.3.5.1 in accordance with Section 2.3.5.1.8 of this ISO Tariff.

11.2.11 FERC Annual Charge Recovery Rate

The ISO shall calculate and levy the rates for recovery of FERC Annual Charges in accordance with Section 7.5 of this ISO Tariff.

11.2.12 Creditworthiness Surcharge

Notwithstanding anything to the contrary in the ISO Tariff, and until the FERC issues any order to the contrary, the following payments and charges shall be increased by a surcharge of 10%:

a) payments at the **Ancillary Services Marginal Price** ~~Market Clearing Price for Ancillary Services~~ as determined in accordance with **Settlement and Billing Protocol Appendix C**~~Sections 2.5.27.1 to 2.5.27.4~~;

b) charges at the **Ancillary Services Marginal Price** ~~Market Clearing Price for Ancillary Services~~ as determined in accordance with **Settlement and Billing Protocol Appendix C**~~Sections 2.5.28.1 to 2.5.28.4~~;

c) payments for Energy delivered in response to incremental Dispatch **I**~~i~~nstructions at the Marginal Proxy Clearing Price **at the Location** or the **Locational Marginal Price**~~Non-Emergency Clearing Price~~, as applicable; and

d) charges for Net Negative Uninstructed Deviations.

11.2.13 Emissions~~ and Start-Up Fuel~~ Cost Charges

The ISO shall calculate, account for and settle charges and payments for Emissions Costs ~~and Start-Up Fuel Costs~~ in accordance with Sections 2.5.23.3.6 ~~and 2.5.23.3.7~~ of this ISO Tariff.

* * *

11.4.3 Data Files.

Settlement Statements relating to each Scheduling Coordinator shall be accompanied by a data file of supporting information that includes the following for each Settlement Period of the Trading Day on a Load Zone~~-by-Zone~~ basis:

(a) the aggregate quantity (in MWh) of Energy supplied or withdrawn by the Metered Entities represented by the Scheduling Coordinator;

(b) the aggregate quantity (in MW) and type of Ancillary Services capacity provided or purchased;

(c) the relevant prices that the ISO has applied in its calculations;

(d) details of the Scheduled quantities of Energy and Ancillary Services accepted by the ISO in the Day-Ahead Market and the Hour-Ahead Market;

(e) details of Imbalance Energy and penalty payments; and

(f) detailed calculations of all fees, charges and payments allocated amongst Scheduling Coordinators and each Scheduling Coordinator's share.

11.5 Calculation in the Event of Lack of Meter Data for the Balancing of Market Accounts.

Settlements shall not be cleared for final processing until the accounting trial balance is zero. In order to publish a Settlement Statement, the ISO may use estimated, disputed or calculated Meter Data . When actual verified Meter Data is available and all of the disputes raised by Scheduling Coordinators during the validation process described in Section 11.7 of this ISO Tariff have been determined, the ISO shall recalculate the amounts payable and receivable by the affected Scheduling Coordinators or by all Scheduling Coordinators, if applicable, as soon as reasonably practical and shall show any required adjustments as a debit or credit in the next Settlement Statement.

* * *

21. [Not Used] ~~GENERATION METER MULTIPLIERS.~~

~~21.1 Temporary Simplification Relating to GMM Loss Factors.~~

~~Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, in determining whether a Schedule is a Balanced Schedule, no allowance shall be made for Transmission Losses (i.e. the Generation Meter Multiplier shall be set at 1.0) for the PX and all other Scheduling Coordinators.~~

~~21.2 Application.~~

~~Notwithstanding any other provision in this Tariff, including the ISO Protocols, the temporary simplification measure specified in this Section 21 shall have effect until discontinued by a Notice of Full-Scale Operations issued by the Chief Executive Officer of the ISO.~~

~~**21.2.1** Pursuant to Subsections 21.3.1 and 21.3.2, the Chief Executive Officer of the ISO shall give notice to all Scheduling Coordinators, except the PX, that such Scheduling Coordinators shall use forecasted Generation Meter Multipliers, as published by the ISO, in their Schedules. Such notice shall be given only after the Chief Executive Officer determines that the ISO is capable of accepting schedules using the forecasted Generation Meter Multipliers without adversely affecting operations or reliability.~~

~~**21.2.2** Pursuant to Subsections 21.3.1 and 21.3.2, the Chief Executive Officer of the ISO shall give notice to the PX that the PX shall use forecasted Generation Meter Multipliers, as published by the ISO, in its Schedules, upon mutual agreement by the Chief Executive Officers of the ISO and PX that the PX is capable of providing schedules pursuant to this Tariff using the ISO's forecasted Generation Meter Multipliers without adversely affecting operations or reliability.~~

~~**21.3** Notices of Full-Scale Operations.~~

~~**21.3.1** When the Chief Executive Officer of the ISO determines that the ISO is capable of implementing this Tariff, including the ISO Protocols, without modification in accordance with a temporary simplification measure specified in this Section 21, he shall issue a notice ("Notice of Full-Scale Operations") and shall specify the relevant temporary simplification measure and the date on which it will permanently cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.~~

~~21.3.2 A Notice of Full-Scale Operations shall be issued when it is posted on the ISO Internet "Home Page," at~~ http://www.caiso.com ~~or such other Internet address as the ISO may publish from time to time.~~

22. **[Not Used]** ~~**SCHEDULE VALIDATION TOLERANCES.**~~

~~**22.1 Temporary Simplification of Schedule Validation Tolerances.**~~

~~Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, a Schedule shall be treated as a Balanced Schedule when aggregate Generation, adjusted for Transmission Losses, is within 20 MW of aggregate Demand, or such lower amount, greater than 1 MW, as may be established from time to time by the ISO. The ISO may establish the Schedule validation tolerance level at any time, between a range from 1 MW to 20 MW, by giving seven days' notice published on the ISO's "Home Page," at http://www.caiso.com or such other Internet address as the ISO may publish from time to time.~~

~~**22.2 Application.**~~

~~Notwithstanding any other provision in this Tariff, including the ISO Protocols, the temporary simplification measure specified in this Section 22 shall have effect until discontinued by a Notice of Full-Scale Operations issued by the Chief Executive Officer of the ISO.~~

~~**22.3 Notices of Full-Scale Operations.**~~

~~**22.3.1** When the Chief Executive Officer of the ISO determines that the ISO is capable of implementing this Tariff, including the ISO Protocols, without modification in accordance with a temporary simplification measure specified in this Section 22, he shall issue a notice ("Notice of Full-Scale Operations") and shall specify the relevant temporary simplification measure and the date on which it will permanently cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.~~

~~**22.3.2** A Notice of Full-Scale Operations shall be issued when it is posted on the ISO Internet "Home Page," at http://www.caiso.com or such other Internet address as the ISO may publish from time to time.~~

23. [NOT USED]

24. [NOT USED]

25. [NOT USED]

26. [Not Used] ~~TEMPORARY CHANGES TO ANCILLARY SERVICES PENALTIES~~

~~26.1 Application and Termination~~

~~The temporary change, respecting Ancillary Services penalties, set out in Section 26.2 shall continue in effect until such time as the Chief Executive Officer of the ISO issues a Notice of Full-Scale Operations, posted on the ISO Internet "Home Page", at http://www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date on which this Section 26 shall cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.~~

~~26.2~~ ~~For so long as this Section 26.2 remains in effect, Scheduling Coordinators shall not be liable for the penalties specified in Section 2.5.26 of the ISO Tariff if, as a result of limitations associated with the ISO's Congestion Management software, the scheduled output of the resource from which the Scheduling Coordinator has committed to provide an Ancillary Service is adjusted by the ISO to a level that conflicts with the Scheduling Coordinator's Ancillary Service capacity commitments, thereby resulting in a failed availability test.~~

27. ~~TEMPORARY RULE LIMITING ADJUSTMENT BIDS APPLICABLE TO DISPATCHABLE LOADS AND EXPORTS~~[Not Used]

~~27.1 Application and Termination~~

~~The temporary change limiting Adjustment Bids for Dispatchable Loads and exports set out in Section 27.2 shall continue in effect until such time as the Chief Executive Officer of the ISO posts a notice ("Notice of Full-Scale Operations"), on the ISO Home Page specifying the date on which this Section 27 shall cease to apply, which date shall not be less than seven (7) days after the Notice of Full-Scale Operations is posted.~~

~~27.2 For so long as this Section 27.2 remains in effect, Scheduling Coordinators shall continue to be allowed to specify Adjustment Bids for Dispatchable Loads and exports, conditioned on the rule that the last segment of the Adjustment Bid (i.e., the maximum MW value) must equal the preferred MW operating point specified for the Dispatchable Load or export.~~

28. RULES LIMITING CERTAIN ENERGY AND ANCILLARY SERVICE BIDS

* * *

28.2.1.1 The 12MMCI is a 12-month rolling price-cost markup index that compares actual average market cost (AAMC) as specified in Section 28.2.1.2 to a competitive baseline average cost (CBAC) as specified in Section 28.2.1.3, using the following formula:

$$12MMCI = (AAMC – CBAC).$$

28.2.1.2 Computation of the AAMC. The actual average market cost is computed as the weighted average of ~~short-term forward~~**Day-Ahead, Hour-Ahead,** and real-time **E**~~e~~nergy prices.

1. ~~The short-term forward e~~**E**nergy prices and quantities ~~use~~ **from the ISO** ~~the~~ ~~d~~**D**ay-**A**~~a~~head and ~~hour~~**Hour**-**A**~~a~~head E~~e~~nergy market**s**. ~~if one is in place. In the absence of forward energy market, the California Energy Resource Scheduler (CERS) day-ahead and hour-ahead scheduled quantities and the corresponding short-term contract prices will be used.~~

2. The real-time prices and quantities pertain to the real-time incremental D~~d~~ispatch I~~i~~nstructions issued by the ISO.

3. The hourly total MWh quantity of the above short-term forward E~~e~~nergy and real-time incremental Imbalance E~~e~~nergy will be used as the quantity for calculating total hourly competitive baseline market costs as described in Section 28.2.1.4.

28.2.1.3 Computation of the CBAC. The competitive baseline average cost is based on competitive baseline prices that represent the estimated variable operating cost of the marginal (highest cost) thermal generation unit within the ISO system needed to meet system D~~d~~emand each hour. The calculation procedure is as follows:

1. The actual supply from Final Hour-A~~a~~head net import schedules, Utility Retained Generation (URG), and other must-take resources within the ISO Control Area are excluded from the computation (i.e. netted out from both S~~s~~upply and D~~d~~emand) for each hour.

~~2.~~2. The operating costs of major non-utility owned thermal generating units within the ISO system are estimated based on unit heat rates, spot market gas prices, opportunity costs for certain E~~e~~nergy limited resources, and estimated variable O&M costs of $4/MWh for combustion turbines and $2/MWh for other thermal units.

~~3.~~3. Only the available capacity of the generating units (considering partial or total outages based on ISO's outage coordination database) are used.

4. A thermal supply curve is developed based on the available capacity of non-utility owned thermal units and their average heat rate.

5. A composite supply curve is constructed by combining the thermal supply curve of Step 4 with real-time import bids that were dispatched, at their bid price, and any Exceptional Dispatch~~out-of-market~~ purchases capped at a price corresponding to a 12,000 MMBTU heat rate (plus the O&M adder)

6. The net D~~d~~emand that must be met by these sources of S~~s~~upply is calculated for each hour t as follows:

Net $Demand_t$ = System Energy $Demand_t$ - HA Net $Imports_t$
- Residual ISO Supply $_t$
- Estimated System Losses and Unaccounted for $Energy_t$

where:

System Energy $Demand_t$ = 1.07*Actual ISO System $Load_t$
+ Upward Regulation $Requirements_t$

HA Net $Imports_t$ = SUMi (Final Hour Ahead Energy $Schedule_{i,t}$)

Residual ISO Supply $_t$ = SUMj (Max [Metered $Output_{j,t}$,
Final Hour Ahead Energy $Schedule_{j,t}$
+ Upward Regulation Capacity $Scheduled_{j,t}$
+ Real Time Energy $Dispatched_{i,t}$
+ RMR Schedule $Change_{j,t}$])

i = All Hour-ahead net import schedules into the ISO control area
j = All generating resources within the ISO control area other than non-utility thermal units

7. System losses and Unaccounted For Energy in each hour t are estimated using the difference between: (1) hourly system loads reported by the ISO based on telemetered data and (2) the sum of estimated generation from all sources within the ISO control area plus final (Hour-Ahead) import schedules.

8. A competitive baseline price is calculated based on the supply curve of non-utility thermal generating units and real-time energy import bids and the net demand that must be met from these sources of supply.

9. For energy-limited resources, estimates of opportunity cost shall be used in computing the competitive baseline cost as described below.

A) Unit owners shall report to the ISO Outage Coordination office when energy-limited resources are not available (for example, once a unit has used up its energy production or its available hours). Annual environmental limitations shall be reported to the ISO Outage Coordination office. The unit will then be flagged so that it is not considered to be physically withholding. Once flagged, the unit will not be included in the calculation of the competitive baseline cost for the relevant period.

B) The opportunity cost for an energy-limited generation resource is calculated based on the maximum available hours during the constrained period and the corresponding price on the price duration curve of the hourly competitive baseline prices for the constrained period. The estimated opportunity cost for the energy-limited generation resource will remain constant for all hours in this constrained period. The opportunity cost may be increased to account for other constraints on the resource.

10. The Hourly Competitive Baseline Cost is the product of:

A) the competitive baseline price defined in this section, and

B) the total ~~short term~~ ~~short-term~~Day-~~A~~ahead and Hour Ahead scheduled Demand~~market clearing quantities~~ and real-time incremental Energy as defined in 28.2.12.

28.2.1.4 Computation of the Price-cost Markup.

The Price-cost markup shall be :

$(SUM_h(\text{Hourly Actual Market Cost}) – SUM_h(\text{Hourly Competitive Baseline Cost})) / SUM_h(\text{Hourly Competitive Baseline Cost})$

where h is each hour in the month;

The 12-Month Market Competitiveness Index (12MMCI) is computed as:

$(SUM_M(\text{Monthly Actual Market Cost}) – SUM_M(\text{Monthly Competitive Baseline Cost})) / SUM_M(\text{Monthly Competitive Baseline Cost})$

where M is each month of the previous 12 months.

* * *

28.2.3.4 Notification to the Commission

It the 12MMCI threshold in Section 28.2.1 is exceeded, the ISO will, in addition to the reinstitution of the California-only mitigation measures contained in Section 28.2.3.1, 28.2.3.2, and 28.2.3.3, notify the Commission as soon as is practical and request the Commission re-institute the West-wide mitigation components of its June 19, 2001 Order in Docket No. EL00-95. The ISO shall also request that, to the extent not already provided, FERC establish liability for refunds in future periods based on the principles provided for in FERC's June 19 2001 Order until FERC makes a finding that rates are just and reasonable.

* * *

29. [NOT USED]

30. YEAR 2000 COMPLIANCE

* * *

~~**31. EXPIRATION OF COMMISSION MITIGATION MEASURES**~~

~~The limitations on prices specified in Sections 2.5.22, 2.5.23, and 2.5.27, and the must-offer obligation specified in Section 5.11, shall expire on September 30, 2002.~~

31. MARKET DESIGN 2002

31.1 Two-Days-Ahead Advisory Information

By 6:00 p.m. two days prior to each Trading Day, the ISO shall publish on OASIS information for each Settlement Period of the Trading Day as set forth in Scheduling Protocol Section 3.2.1.

31.2 Day-Ahead Market

The ISO shall publish on OASIS information for each Settlement Period of the Trading Day as set forth in Scheduling Protocol Section 3.2.2.

31.2.1 Transmission Rights Information

Participating Transmission Owners shall provide, and the ISO shall publish information regarding transmission rights as set forth in Scheduling Protocol Sections 3.2.4 and 3.2.5.

31.2.2 Reliability Must-Run Requirements

By no later than two hours before the deadline for submitting Initial Preferred Day-Ahead Schedules on the day ahead of the Trading Day, the ISO will notify Scheduling Coordinators 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"). In those instances where a Reliability Must-Run unit requires more than one day's notice, the ISO may notify the applicable Scheduling Coordinator more than one day in advance of the Trading Day. 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.

31.2.2.1 Selection of Payment Option for Reliability Must-Run Requirements

No later than one hour following the receipt of the RMR Dispatch Notice described in Section 2.2 from the ISO, any RMR Owner receiving an RMR Dispatch Notice as indicated in this Section

2g.2.1 (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, and receiving only market compensation therefore (the "RMR Market Option"), or (ii) by delivering the RMR Energy as a contract transaction, and accepting payment under the relevant RMR Contract (the "RMR Contract Option"). If the Applicable RMR Owner so notifies the ISO by January 1 of any 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.

31.2.2.1.1. RMR Contract Option

For each hour for which the Applicable RMR Owner elects the RMR Contract Option ("Contract Hour"), it shall schedule at least the entire amount of the RMR Energy for that hour into the Day-Ahead Market as a Supply Price Taker in accordance with section 31.2.3.1.4.2.3. RMR Energy for each Contract Hour shall receive the highest scheduling priority during the Day-Ahead Market. If there is insufficient scheduled Demand to accommodate all RMR Energy in the Day-Ahead Market, however, some RMR schedules may be reduced and the unscheduled RMR Energy will be predispatched for real time through the Day-Ahead Residual Unit Commitment Process. Whether or not the RMR Energy is in the Final Schedule, the Applicable RMR Owner must deliver the RMR Energy pursuant to the RMR Dispatch Notice. All RMR Energy delivered under this option shall be deemed delivered under a Non-market Transaction for the purposes of the RMR Contract.

31.2.2.1.2 RMR Market Option

For each hour for which an Applicable RMR Owner has selected the Market Option ("Market Hour"), the Applicable RMR Owner (i) may bid into the ISO's Day-Ahead Market any amount of the RMR Energy and (ii) may schedule as a bilateral Day-Ahead transaction any amount of RMR Energy. Energy bids for any amount of RMR Energy during each Market Hour shall be submitted pursuant to Section 31.2.3.2.3.3.1.3. Any amount of RMR Energy not included in the Final Day-

Ahead Energy Schedules must be bid into the Hour-Ahead Market as a Supply Price Taker. Any amount of RMR Energy not included in the Final Hour-Ahead Energy Schedules shall be pre-dispatched for real-time through the Hour-Ahead Residual Unit Commitment process. Notwithstanding anything to the contrary in the RMR Contract, neither the Applicable RMR Owner nor the Applicable RMR SC shall be entitled to any payment from any source for RMR Energy that is not bid and scheduled as required by this Section 31.2.2.1.2.

In the event that the RMR Energy is not delivered, (i) if the RMR Energy had been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and the Applicable RMR SC shall pay for the Imbalance Energy necessary to replace that RMR Energy, or (ii) if the RMR 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 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.

31.2.2.1.2.1 The Applicable RMR SC's Preferred Hour-Ahead Schedule for each Market Hour shall include all RMR Energy specified in the RMR Dispatch Notice for that Market Hour. If the Final Hour-Ahead Schedule of the Applicable RMR SC for any Market Hour includes Energy Bids for the RMR Unit, the Energy Bids shall specify the RMR Energy as the minimum MW output to which the Applicable RMR SC will allow the RMR Unit to be redispatched for that Market Hour.

31.2.2.1.2.2. Whether or not the RMR Energy is in the Final Hour-Ahead 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 31.2.2.1.2, 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 SC shall be entitled to any payment from any source for RMR Energy that is not bid and scheduled as required by this Section 31.2.2.1.2.

31.2.2.1.3 Supplemental RMR Dispatch Notice

If, at any time after the two hours before the deadline for submitting Initial Preferred Day-Ahead Schedules 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 ISO issues the Supplemental RMR Dispatch Notice less than two hours before the deadline for submitting Hour-Ahead Preferred Schedules for any particular hour of the Trading Day, the Energy specified in the Supplemental Dispatch Notice for such particular hour shall be exempt from the bidding and scheduling requirements and the pricing provisions of this Section 31.2.2.1.3, except that, if the owner of the RMR Unit has already selected a payment option for any hour, the RMR Owner will be paid for that RMR Energy in that particular hour according to that payment option. If the owner of 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 one hour after receipt of the RMR Dispatch Notice and the elected payment option for such hour shall apply to RMR Energy bid into that and subsequent ISO markets for such hour during the Trading Day.

31.2.2.1.4 ISO Analysis of RMR Preferred Schedules

On receipt of the Preferred Schedules, the ISO will analyze the Preferred Schedules of Applicable RMR SCs to determine the compatibility of such Preferred Schedules with the RMR Dispatch Notices.

31.2.3 Day-Ahead Energy and Ancillary Services Market

31.2.3.1 Security Constrained Unit Commitment

The Day-Ahead Energy and Ancillary Services market shall clear simultaneously for all the hours of the Trading Day. A multi-hour optimization methodology, referred to as Security Constrained Unit Commitment (SCUC), shall be employed to simultaneously perform the following tasks:

a) Conduct a Day-Ahead Energy market to clear Supply and Demand bids for each hour of the Trading Day to yield final Day-Ahead Energy Schedules;

b) Clear the Day-Ahead Ancillary Services market by selecting capacity for each hour of the Trading Day to meet that hour's Ancillary Services requirements;

c) Efficiently allocate transmission capacity to final Day-Ahead Energy and Ancillary Services Schedules by resolving transmission Congestion; and

d) Commit unscheduled resources at least cost to meet the Energy, Ancillary Services, and Congestion Management requirements throughout the Trading Day.

These tasks will be described in detail in the following sections.

31.2.3.1.1 Formulation

The objective of the Security Constrained Unit Commitment shall be to minimize the overall cost of Day-Ahead Energy and Ancillary Services procurement over the entire set of hours that shall consist of the time horizon, subject to network constraints and resource operating constraints. The overall procurement cost shall be determined by the total of the start-up and minimum load costs of ISO-committed resources, the Energy bids of all scheduled resources, and the Ancillary Services bids of resources selected to provide Ancillary Services. Network constraints include power flow limits on transmission facilities, voltage limits, and limits on other transmission controls. Resource constraints include operating limits and inter-temporal constraints. The technical formulation of SCUC is given and discussed in Appendix B.

31.2.3.1.2 Unit Commitment

31.2.3.1.2.1 Unit Commitment Definitions

The following definitions are used in this Tariff in association with Unit Commitment:

- *Time period.* The unit of time for scheduling activities, currently an hour. Resource Schedules are constant throughout the time period.
- *Time horizon.* A number of contiguous time periods over which an optimal Schedule is produced.
- *Commitment status.* The dual on/off state for each unit in each time period. A unit is off when it is offline or in the process of starting up or shutting down. A unit is on when it is online and synchronized with the grid. An off-on transition signifies a start-up and an on-off transition signifies a shutdown.
- *Unit operating constraints.* The feasible scheduling of generating resources over a time horizon requires consideration of a multitude of operating constraints:
    - *Availability status.* The status of a unit with respect to planned or forced outages.
    - *Start-up time.* The time required for a unit to start up after notification.

- *Minimum up time (MUT).* The minimum time that a unit must stay on after a start-up.
- *Minimum and maximum operating limits.* The power output limits of a unit while it is on. The minimum operating limit is also referred to as the *minimum load*.
- *Shutdown time.* The time required for a unit to shut down.
- *Minimum down time (MDT).* The minimum time that a unit must stay off after a shutdown. The minimum down time includes the shutdown and start-up time.
- *Maximum number of daily start-ups*. The maximum number of times that a unit is allowed to start up within a day.
- *Ramp rate.* The rate at which a unit increases or decreases its power output to perform schedule changes across time periods.
- *Energy limit.* The limit on the total Energy output of an energy-limited resource over the time horizon.
- *Operational dead-bands*. Operating ranges in which the resource produces Energy but is not dispatchable.

Availability, and start-up and minimum up/down times (rounded up to the next integer multiple of the time period) affect the commitment status, whereas ramp rate and operating/energy limits affect the schedule of units. The maximum number of daily start-ups limits unit cycling within a day.

- *Unit costs.* The optimal scheduling of generating resources over a time horizon requires consideration of a multitude of unit costs:
    - *Start-up cost.* The cost incurred when a unit starts up. This cost is a function of past down time. The start-up cost generally increases as down time increases.
    - *Shutdown cost.* The cost incurred when a unit shuts down. For simplicity, the shutdown cost is included in the start-up cost.
    - *Minimum load cost.* The cost incurred when a unit is operating at minimum load.

- *Incremental energy cost.* The incremental Energy cost (the cost of producing the next increment of power) of a unit at a given operating point.

The optimal Schedules produced by SCUC minimize the start-up and Energy cost of all resources over the entire time horizon. The Energy cost is calculated as the minimum load cost plus the integral of the incremental Energy cost from minimum load to final schedule.

- *Commitment period.* The time span of contiguous time periods where a unit is on. The commitment period extends from a start-up to a shutdown and it may span several days. The commitment period may not be less than the MUT, however, for practical reasons, the commitment period will be limited to a single day, in which case it may split over several contiguous commitment periods.
- *Self-commitment period.* The portion of the commitment period of a unit that submits Energy Schedules or is selected to provide Ancillary Services, except for units providing Non-Spinning Reserve that can start and synchronize to the grid in less than ten minutes, typically hydro units and combustion turbines (CTs). The self-commitment period may include time periods where the unit does not submit Schedules or is awarded Ancillary Services, if it is determined by inference that the unit must be on due to MUT/MDT constraints. For example, the self-commitment period of a unit that self-commits in hour h will be $[h, h + MUT]$. Similarly, the self-commitment period of a unit that self-commits in hours h and $h + n$ will be $[h, h + \max(n, MUT)]$ if $n < MUT + MDT$.
- *ISO-commitment period.* The portion of the commitment period that is not a self-commitment period.
- *Qualifying hour.* The hour of an ISO-commitment period when a unit is not Dispatched under its RMR Contract.
- *Unit Commitment cost.* The unit commitment cost over a commitment period is composed of the minimum load cost for each qualifying hour in ISO-commitment periods, plus the start-up cost if 1) there is no self-commitment within the commitment period; 2) the unit is required to start and 3) it actually starts up. A unit that incurs start-up costs at the direction of the ISO but does not complete the start-up shall be treated in accordance with Section 5.12.7.1.2. The unit may not be required to start if the commitment period immediately follows a previous commitment period. Units are not

eligible to recover start-up costs that they do not actually incur. For example, a unit may remain on from a prior commitment period or may fail to start-up as instructed.

- *Unrecovered Commitment Cost.* The portion of the unit commitment cost over all qualifying hours in a commitment period that is not recovered from market revenues from the Day-Ahead and Hour-Ahead Energy and Ancillary Services markets and the Real-Time Imbalance Energy market during the same hours, as calculated in SABP Appendix H.

31.2.3.1.2.2 Time Horizon

Although the objective of SCUC is to produce optimal Schedules for each hour of the Trading Day, a time horizon longer than 24 hours is required for efficient scheduling. The time horizon should include at the minimum the peak hours of the day that follows the Trading Day so that SCUC will not unnecessarily cycle long-start units at the end of the Trading Day. To consider the lower Demand levels during weekends and holidays, and also the Energy limits of Energy-limited resources, the time horizon would need to be even longer. Depending on the capability and performance of the software and hardware that the ISO will procure and use for the SCUC implementation, the time horizon shall be a *rolling window* of up to five (5) days (120 hours), starting with the Trading Day. The SCUC shall replicate Schedules and Bids submitted for the Trading Day shall be for the following four days (with appropriate adjustments for Demand Forecast changes) to provide for continuity. The resulting optimal Schedules for the Trading Day shall constitute the final Day-Ahead Energy and Ancillary Services Schedules. The optimal Schedules for the remaining four days past the Trading Day will be for the ISO's advisory use only. The ISO shall provide sufficient advance notice to Units with start-up times greater than 24 hours that the Advisory schedules indicate should be started. The resource shall be required to remain committed as set forth in Section 2.3.1.2..

31.2.3.1.2.3 Self-Commitment

Resources that submit preferred Energy Schedules in a given hour, or are selected to provide Ancillary Services (bid or self-provided), except for units providing Non-Spinning Reserve that can start and synchronize to the grid in less than ten minutes, shall be deemed self-committed by SCUC in that hour. SCUC will enforce operating constraints for self-committed resources. As a result, these resources may be deemed self-committed (and scheduled to at least their minimum load) also during hours that they do not submit preferred Energy Schedules, if the resources are required to be on due to their MUT and/or MDT constraints. Furthermore, preferred Energy Schedules across consecutive hours must be consistent with the relevant ramp rate capabilities, otherwise the Energy Schedules will be adjusted accordingly.

The preferred Energy Schedules of self-committed resources shall be optimized using submitted Energy bids. The adjustments shall bound the final Energy Schedules within the capacity range of the submitted Energy bids and within the relevant minimum and maximum operating limits, taking into account Ancillary Services commitments. However, if the submitted Energy bids are insufficient to resolve Congestion, preferred Energy Schedules may be adjusted, outside the capacity range of submitted Energy bids, or even when no Energy bids are submitted, but within the resource's operating capability, due to pro rata Schedule adjustments in accordance with Section 31.2.3.1.4.2. Moreover, SCUC may de-commit self-committed resources if this measure is necessary to address overgeneration conditions.

SCUC will not consider start-up and minimum load cost bids from self-committed units. Resources shall not be eligible for Unrecovered Commitment Cost compensation during self-committed periods, as set forth in Section 31.2.3.1.2.1.

31.2.3.1.2.4 ISO-Commitment

Resources may submit three-part bids in accordance with Section 31.2.3.1.4.4 so that SCUC may optimally commit and schedule these resources to meet Energy, Ancillary Services, or Congestion Management requirements. SCUC will enforce operating constraints for ISO-committed resources. The final Energy Schedules shall be within the capacity range of the submitted Energy bids and within the relevant minimum and maximum operating limits, taking into account Ancillary Services commitments. However, if the submitted Energy bids are insufficient to resolve Congestion, final Energy Schedules may exceed the upper range of submitted Energy bids due to pro rata Schedule adjustments in accordance with Section 31.2.3.1.4.2 but may not exceed the maximum capability of the resources as expressed to the ISO via the outage coordination process.

Resources may be eligible for Unrecovered Commitment Cost compensation during ISO-committed periods, as set forth in Section 31.2.3.4.4.1.1.1.

31.2.3.1.3 Ancillary Services Procurement

SCUC shall procure Ancillary Services at least cost simultaneous with the scheduling of Day-Ahead Energy for each hour of the Trading Day. Scheduling Coordinators may either self-provide Ancillary Services or they may submit a capacity reservation bid.

31.2.3.1.3.1 Ancillary Services Requirements

Ancillary Services prices and procurement may vary regionally due to regional Ancillary Services procurement constraints that may be enforced in SCUC for reliability purposes. The Ancillary Services requirements, Ancillary Services Regions, and regional procurement constraints shall be determined based on the Day-Ahead Demand Forecast and anticipated Congestion conditions, in accordance with the Ancillary Services Requirements Protocol. This information shall be published prior to the Day-Ahead market in accordance with Section 31.2.1.2. The Ancillary Services regional constraints may impose a minimum or a maximum of Ancillary Services requirements in a given region. These constraints can be used to enforce a minimum regional requirement for reliability purposes, or limit Ancillary Services imports from inter-ties.

31.2.3.1.3.2 Ancillary Services Self-Provision

Scheduling Coordinators may self-provide Ancillary Services as set forth in Section 2.5.7.4.

31.2.3.1.3.3 Ancillary Services Substitutability

SCUC shall allow a) that amount of Regulation Up that can be delivered in ten minutes to satisfy Spinning and Non-Spinning Reserve requirements, and b) Spinning Reserve to satisfy Non-Spinning Reserve requirements, if this substitution would result in a lower overall Ancillary Services and Energy procurement cost.

31.2.3.1.4 Energy Market and Congestion Management

SCUC shall perform Congestion Management simultaneous with Ancillary Services procurement and the scheduling of Day-Ahead Energy for each hour of the Trading Day. Congestion Management is the process where Energy schedules are adjusted to eliminate network constraint violations and minimize the cost of serving Demand.

31.2.3.1.4.1 Modeling

31.2.3.1.4.1.1 Network Model

SCUC shall use the Full Network Model. The Full Network Model will be continuously updated to reflect new transmission and generation projects. Transmission and generation facilities shall be in or out of service in the Full Network Model to reflect the expected system conditions in each hour of the Trading Day.

The Full Network Model shall include a reduced equivalent network for systems external to the ISO Controlled Grid. The modeling detail of the external systems will depend on the level of information available about external Schedules (Supply and Demand outside the ISO Controlled Grid).

31.2.3.1.4.1.2 Transmission Losses

The Full Network Model shall be an AC network model that includes resistances to reasonably account for transmission losses. Therefore, the final Day-Ahead Energy Schedules for Supply shall exceed the final Day-Ahead Energy Schedules for Demand and exports by the amount of transmission losses in the interconnected network. SCUC shall optimally adjust resource Schedules to cover transmission losses.

31.2.3.1.4.1.3 Network Constraints

SCUC shall enforce constraints on transmission lines, transformers, and groups of transmission branches that compose transmission interfaces. Most of these constraints shall be thermal limits on the power flow through the transmission facilities. However, certain constraints may impose more restrictive limits on power flow. These limits will take into account contingencies and reliability considerations, some of which are represented by Nomograms.

31.2.3.1.4.1.4 SCUC Controls

To the extent practical, SCUC controls shall consist of the following: generator real and reactive power output, import and export levels, Demand side management, transformer tap controls, switched reactive devices, High Voltage Direct Current controls, and others.

31.2.3.1.4.2 Default Energy Bids

To alleviate Congestion and produce feasible final Day-Ahead Energy and Ancillary Services Schedules, SCUC may need to adjust resource schedules outside the capacity range of submitted Energy bids. The resource schedule adjustments outside of the capacity range of submitted Energy bids are referred to as “uneconomic adjustments.” Uneconomic adjustments shall be priced at the applicable Bid Caps, in accordance with Section 28.1. Incremental uneconomic adjustments for generation and decremental uneconomic adjustments for load and exports shall be priced at the Bid Ceiling, whereas decremental uneconomic adjustments for generation and imports shall be priced at the Bid Floor. Incremental uneconomic adjustments for generating units shall extend up to their upper operating limit as listed in the Master File and as modified by any limitations reported to the ISO, less any self-provided Ancillary Services capacity. The upper regulating limit shall be used if the unit is scheduled to provide Regulation

Up. Decremental uneconomic adjustments for generating units shall extend down to their lower operating limit plus capacity selected for Regulation Down. The lower regulating limit shall be used if the unit is scheduled to provide Regulation Down. Decremental uneconomic adjustments for imports, exports, and Demand shall extend down to zero MW.

Although all uneconomic adjustments shall be priced at the applicable bid limits, SCUC shall enforce different scheduling priorities among them. Therefore, uneconomic adjustments shall take place in increasing scheduling priority order, from lowest to highest, as needed to resolve Congestion. The different classes of uneconomic adjustments are described in the following subsections in decreasing scheduling priority.

31.2.3.1.4.2.1 Existing Contract Sources and Sinks

Existing Contract Schedules shall be balanced supply and demand Schedules with specified supply sources and demand sinks, and no Energy bids, in accordance with Section 31.2.3.2.6. Existing Contract Schedules shall be given the highest scheduling priority among uneconomic adjustments. Therefore, Existing Contract Schedules may be adjusted only after all other resource adjustments are exhausted. If adjusted, Existing Contract Schedules shall remain balanced.

31.2.3.1.4.2.2 Point-To-Point Firm Transmission Right Sources and Sinks

Point-To-Point (PTP) Firm Transmission Rights (FTRs) optionally provide FTR holders scheduling priority in the Day-Ahead market, in accordance with Section 9.1.1. PTP FTR Schedules are balanced supply and demand Schedules with specified Sources and Sinks, and no Energy bids, in accordance with Section 31.2.3.2.7. PTP FTR Schedules shall be given the second highest scheduling priority among penalty adjustments after Existing Contract Schedules. Therefore, PTP FTR Schedules may be adjusted only after all other effective non-Existing Contract Schedule adjustments are exhausted. If adjusted, PTP FTR Schedules shall remain balanced.

31.2.3.1.4.2.3 RMR Energy

RMR Energy bid as a Price Taker shall be given the next highest scheduling priority after Existing Contract Schedules and FTR Schedules.

31.2.3.1.4.2.4 Supply and Demand Price Takers

Supply and Demand Price Takers are Supply and Demand Schedules (or portions thereof) without Energy bids. Supply price takers are selling Energy in the Day-Ahead Market at any price down to the Bid Floor. Similarly, Demand Price Takers are buying Energy in the Day-Ahead Market at any price up to the Bid Ceiling. Consequently, SCUC shall not adjust these Schedules until all other Schedules with Energy bids are fully adjusted.

The Schedules of any Demand or export bid as a Price Taker may be reduced when the Locational Marginal Price at their Location reaches the Bid Ceiling.

31.2.3.1.4.3 Locational Marginal Pricing

SCUC shall calculate Locational Marginal Prices (LMPs) for Energy and Ancillary Services Marginal Prices (ASMPs), as described in Tariff Appendix K.. The LMPs for Energy shall be calculated for each network node and Load Aggregation Point or Trading Hub, and shall be used for Energy Settlements in accordance with Section 31.2.3.4.1. The ASMPs shall be calculated for each region and shall be used for Ancillary Services Settlements in accordance with Section 31.2.3.4.2.

The LMP at a network node, also referred to as the nodal price, is the marginal cost of serving the next increment of Demand at that node. The LMP is composed of the system marginal cost of Energy, the marginal cost of transmission losses, and the marginal cost of binding network constraints, i.e., network constraints that are active at the optimal solution prohibiting a lower cost outcome.

The LMP at a Load Aggregation Point or Trading Hub shall be the weighted average of the nodal prices of all underlying nodes so that the Energy Settlement using the LMP at the Load Aggregation Point or Trading Hub is equal to the Energy Settlement at all underlying nodes using the corresponding nodal prices. The load distribution from the Load Aggregation Point or Trading Hub down to the underlying nodes shall be determined by the relevant Load Distribution Factors (LDFs). The LDFs for Trading Hubs and Load Zones shall be used in accordance with Section 31.2.3.2.1 and published prior to the Day-Ahead market in accordance with Section 31.2.1.5. The LDFs for Customer Aggregations shall be validated and used in accordance with Section 31.2.3.2.1.2.

The ASMP for a given Ancillary Service in a given Ancillary Service Region is the marginal cost of providing that service in that region, which is the highest cost for providing that service among all selected resources in that region. The Ancillary Service cost for a given resource is its capacity reservation bid for that service plus the opportunity cost of reserved capacity for that service. The opportunity cost of reserved capacity is the difference between the LMP at the location of the resource and the Energy bid of the resource at its Energy Schedule. There is no opportunity cost for providing any Ancillary Service from Demand. There is also no opportunity cost for Ancillary Services provided by imports since the associated capacity is not linked to Energy Schedules.

31.2.3.1.4.4. Ancillary Services and Congestion

SCUC shall use regional procurement constraints when determining Ancillary Services requirements. SCUC shall not reserve Available Transmission Capacity (ATC) within regions for Ancillary Services. Similarly, no ATC shall be reserved for Ancillary Services between regions, with the only exception of inter-tie capacity in the import direction for Ancillary Services from imports. SCUC shall allocate inter-tie capacity in the import direction among net Energy imports and Ancillary Services from imports to minimize total cost. If an inter-tie is congested in the import direction, the marginal cost of ATC reserved for Ancillary Services imports shall be charged explicitly to the relevant Ancillary Services providers, in accordance with Section 31.2.3.4.2.3. The marginal cost of ATC reservation for Ancillary Services imports shall be the shadow price of the congested inter-tie (i.e., the marginal cost of relieving the congestion on that inter-tie, as calculated by SCUC), if the inter-tie is congested in the import direction.. Consequently, the loop flow due to the external network equivalent shall be ignored for Ancillary Services imports.

31.2.3.1.4.5 Local Market Power Bid Mitigation

If the ISO must Dispatch a Generating Unit as a direct result of Congestion within the ISO Controlled Grid that cannot be managed competitively in either the Day-Ahead, Hour-Ahead, or real-time Imbalance Energy Markets, the ISO shall, prior to establishing final LMPs, set the price of the bid from that Generating Unit equal to the default Energy bid price of that Generating Unit as determined in accordance with Sections 5.12.5.1.4.1.3 and 5.12.5.1.4.2.3. For Generating Units

not subject to the default Energy bid prices described in Sections 5.12.5.1.4.1.3 and 5.12.5.1.4.2.3, the ISO shall calculate default Energy bid prices utilizing the methodology described below. The Scheduling Coordinator for that Generating Unit shall then be 1) paid the applicable Locational Marginal Price for incremental Dispatch, or 2) charged the applicable Locational Marginal Price for decremental Dispatch.

For Generating Units not subject to the default energy bid prices described in Sections 5.12.5.1.4.1.3 and 5.12.5.1.4.2.3, the ISO shall calculate default Energy bid prices utilizing the following methodology, listed in order of preference subject to the existence of sufficient data:

1. The mean of the Day-Ahead, Hour-Ahead, and real-time Locational Marginal Prices for the units' relevant Location during the lowest-priced 25 percent of the hours that a) the unit was Dispatched or Scheduled, and b) the unit's bid was not mitigated as set forth in this section, over the previous 90 days for peak or off-peak periods, as applicable, adjusted for changes in fuel prices; or
2. A level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the application of the mitigation, and provided the Market Participant has provided sufficient data on a unit's Energy limitations and operating costs (including opportunity cost for Energy limited resources) in accordance with specifications provided by the ISO.
3. If the ISO cannot calculate default bids on the basis of the first and second methods, the ISO shall determine default bids on the basis of:
   - the ISO's estimated costs of that Generating Unit, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or
   - an appropriate average of competitive bids of one or more similar units.

31.2.3.2 Scheduling Requirements

SCs will have the option to submit Balanced Schedules but will not be required to submit Balanced Schedules.

31.2.3.2.1 Load Aggregation

Load will be represented in Congestion Management at a nodal level. For scheduling and settlement, a Scheduling Coordinator may schedule Load at an aggregated level, or alternatively at a nodal level if they are registered to schedule at the location in the ISO Master File. The ISO will maintain on the ISO Home Page a list of defined Load Zones and sub-zones that comprise standard Load aggregations for this purpose, including the buses within each Load Zone and sub-zone. The ISO shall provide Final Day-Ahead Schedules and Final Hour-Ahead Schedules at the same aggregation level that Scheduling Coordinators specified when they submitted their Schedules. Scheduling Coordinators that established Customer Aggregations in accordance with Section 31.2.3.2.1.2 must schedule using the established Customer Aggregations. Final Schedules for forward market transactions scheduled using a Customer Aggregation shall be settled using that Customer Aggregation. Final Schedules for forward market transactions not scheduled using a Customer Aggregation shall be settled using the Locational Marginal Price for that Load Zone.

Scheduling Coordinators must submit Settlement Quality Meter Data for Loads to the ISO using the same aggregations that were used in scheduling. Deviations between Final Hour-Ahead Schedules and the Settlement Quality Meter Data will be settled at the relevant Dispatch Interval Locational Marginal Price as set forth in Section 31.4.3.2.4 for each Load Zone or Customer Aggregation if established in accordance with Section 31.2.3.2.1.2).

A Scheduling Coordinator may bid Dispatchable Load as an aggregation of Loads that are a) individually under 1 MW, b) served from the same bus, or c) within a single Load Zone but on different buses (e.g., pumping loads within the same watershed or water delivery system) upon ISO agreement on a case-by-case basis. Dispatchable Load must be scheduled using Load Aggregation Points assigned by the ISO. A Dispatchable Load Load Aggregation Point must be within one Load Zone. Dispatchable Load cannot be bid at the level of the PGE3 or SCE1 Load Zones, but must be bid in sub-zones of these Load Zones.

31.2.3.2.1.1 Distribution Factors

The ISO shall publish Load Distribution Factors (LDFs) for Load Zones and Trading Hubs that represent the relative amount of Load at each bus within the Load Zone or Trading Hub, as set forth in Scheduling Protocol Section 3.2.1. The ISO will use LDFs to allocate aggregated Load to buses. LDFs will also be used as weighting factors to calculate average Load Zone and Trading

Hub prices for Settlement of aggregated Loads and Inter-Scheduling Coordinator Trades. The ISO may use updated LDFs that are based on more recent or more detailed information from the Residual Unit Commitment Process. LDFs include the following:

31.2.3.2.1.1.1. Standard Aggregation Scheduling Distribution Factors.

Standard Aggregation Scheduling Distribution Factors are used for scheduling purposes and for settling forward market transactions. They apply to seasonal on and off-peak periods. They are determined by the ISO from actual historical load patterns from State Estimator solutions. If the ISO determines that valid State Estimator solutions are not available for a particular set of conditions, the ISO may use other historical power flow modeling based on WSCC base case to determine these factors. The ISO will update these factors annually, and may update them more frequently if the ISO determines there has been a significant change in underlying conditions. The ISO may adjust Standard Aggregation Scheduling Distribution Factors to account for Demand associated with Customer Aggregations.

31.2.3.2.1.1.2 Standard Aggregation Meter Distribution Factors.

Standard Aggregation Meter Distribution Factors are used for settling real-time transactions and deviations. They are determined by the ISO for each hour using State Estimator solutions. If the ISO determines that valid State Estimator solutions are not available for a particular set of conditions, the ISO may use other means, including using factors from hours with similar system conditions, to determine these factors. The ISO shall adjust Standard Aggregation Meter Distribution Factors to account for Demand associated with Customer Aggregations using Settlement Quality Meter Data.

31.2.3.2.1.1.3 Customer Aggregation Scheduling Distribution Factors

Customer Aggregation Scheduling Distribution Factors are used for scheduling purposes and for settling forward market transactions. They are determined by Load Serving Entities and submitted to the ISO by Scheduling Coordinators.

31.2.3.2.1.1.4 Customer Aggregation Meter Distribution Factors

Customer Aggregation Meter Distribution Factors are used for settling Imbalance Energy. They are established either by meter data or through agreement of the LSE and the UDC.

31.2.3.2.1.2 Customer Aggregation

To reflect the characteristics of Loads that do not vary in proportion to the total load in their Load Zone, Load Serving Entities may elect to schedule Loads using a Customer Aggregation rather than the default Load Zone aggregation. A Customer Aggregation may consist of Load at a single bus or multiple buses, and a Schedule of Demand at a single bus is to be treated as a Customer Aggregation. A Load Serving Entity that elects to schedule Load using a Customer Aggregation must provide Customer Aggregation Scheduling Distribution Factors that reflect its intent in scheduling Energy in forward markets, and either (a) establish a process for calculating Customer Aggregation Meter Distribution Factors corresponding to its Customer Aggregation, or (b) provide Settlement Quality Meter Data at the nodal level. Once a Load Serving Entity establishes a Customer Aggregation, the Scheduling Coordinator representing the Load Serving Entity must use the Customer Aggregation established by that Load Serving Entity for the following twelve months. The Load Serving Entity may update its Customer Aggregation only to add or remove end-use Loads due to customer migration.

To establish a Customer Aggregation, a Load Serving Entity must provide to the ISO the Universal Node Identifier (UNI) of the participating end-use customers in CPUC-jurisdictional service areas, or similar site identifiers in other areas, which may be established by the Local Regulatory Authority but must, at a minimum, identify the applicable Take Out Point from the ISO Controlled Grid. The ISO may use UNIs to track MWh usage among Load aggregations, recompute LDFs when customers switch between Load aggregations, ensure that all customers are served by one and only one Scheduling Coordinator, and perform other monitoring functions as required. The Loads comprising a Customer Aggregation do not need to be at contiguous buses, but must be within a single UDC's service area. Customer Aggregations must not cross certain boundaries designated by the ISO, including Path 15 and Path 26.

Once a Load Serving Entity has established a Customer Aggregation, the Scheduling Coordinator for the Load Serving Entity shall provide the Customer Aggregation Scheduling Distribution Factors to the ISO. Scheduling Coordinators must submit hourly factors that shall apply as a default if updated factors are not provided through the scheduling process. Updated factors may be submitted as often as once per day. Submitted factors are binding for both Day-Ahead and Hour-Ahead settlements. If no Customer Aggregation Scheduling Distribution Factors have been submitted, the ISO will use the Standard Aggregation Scheduling Distribution Factors determined by the ISO for the Load Zone.

If the Scheduling Coordinator for a Load Serving Entity chooses not to submit Customer Aggregation Meter Distribution Factors, it must submit Settlement Quality Meter Data at the

nodal level for Loads in a Customer Aggregation. Because the use of a Customer Aggregation for Settlement will affect the relative weighting of Loads that are served by the host UDC within the Load Zone, and because the UDC will generally have historical data on the Energy usage of the affected Loads, the Load Serving Entity must obtain the UDC's agreement for any proposed Customer Aggregation Meter Distribution Factors. The Load Serving Entity and Scheduling Coordinator must provide accurate Settlement Quality Meter Data, and ensure consistency and auditability by the ISO in any process that uses Customer Aggregation Meter Distribution Factors for determining actual usage for Settlement of the Real Time Market.

31.2.3.2.2. Obligation to Offer Available Capacity

All Participating Generators shall offer to sell in the ISO's Day-Ahead Energy and Ancillary Services markets, Hour-Ahead Energy and Ancillary Services markets, Day-Ahead and Hour-Ahead Residual Unit Commitment Processes, and Real Time Imbalance Energy markets in all hours, all Available Generation from non-hydroelectric Generating Units owned or controlled by the Participating Generators as set forth in this section. Non-hydroelectric Generating Units owned or controlled by the Participating Generators shall be designated as Capacity Resources.

Other Capacity Resources shall offer available capacity in the ISO's Day-Ahead Energy and Ancillary Services markets, Hour-Ahead Energy and Ancillary Services markets, Day-Ahead and Hour-Ahead Residual Unit Commitment Processes, and Real Time Imbalance Energy markets in all hours as required by any agreements they have.

31.2.3.2.2.1. Available Generation

Available Generation is the Generation available for a market if the resource's current status and operational constraints allow the resource to deliver Energy or provide Ancillary Services in accordance with a Schedule that may be established for, or an award that may be made in, that market.

31.2.3.2.2.1.1. Day-Ahead Markets

A A Generating Unit's Available Generation for bidding into the ISO's Day Ahead Energy and Ancillary Services Markets 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 Sections 2.3 and 5.11.3 and adjusted 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 preferred scheduled operating point, if any, as identified in the SC's Day-Ahead Preferred Schedule, (c) minus the Generating Unit's capacity committed to self-provide Ancillary

Services to the ISO, and (d) if the Generating Unit is owned by a Load Serving Entity, minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the Load Serving Entity's native load.

31.2.3.2.2.1.2 Residual Unit Commitment Process

A Generating Unit's "Available Generation" for bidding into the Residual Unit Commitment Process 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 Sections 2.3 and 5.11.3 and adjusted 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, if any, as identified in the ISO's Final Day-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) if the Generating Unit is owned by a Load Serving Entity, minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the Load Serving Entity's native load.

31.2.3.2.2.1.3 Hour-Ahead Market

A Generating Unit's "Available Generation" for bidding into the Residual Unit Commitment Process 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 Sections 2.3 and 5.11.3 and adjusted 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, if any, as identified in the ISO's Final Day-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) if the Generating Unit is owned by a Load Serving Entity, minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the Load Serving Entity's native load.

31.2.3.2.2.1.4 Real-Time Imbalance Energy Market

A Generating Unit's "Available Generation" for bidding into the ISO Real Time Imbalance Energy Market 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 Sections 2.3 and 5.11.3 and adjusted 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, if any, 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, (d) if the Generating Unit is owned by a Load Serving Entity, minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the Load Serving Entity's native load.

31.2.3.2.3 Bidding

31.2.3.2.3.1. Participation

31.2.3.2.3.1.1. Capacity Resources.

Scheduling Coordinators must submit bids from Capacity Resources in the Day-Ahead Market as set forth in Section 31.2.3.2.3.5.

31.2.3.2.3.1.2 Generating Units.

Scheduling Coordinators may submit bids from Generating Units in the Day-Ahead Markets as set forth in Section 31.2.3.2.3.3.1.

31.2.3.2.3.1.3 Load.

Scheduling Coordinators may bid Load in the Day-Ahead Markets as set forth in Section 31.2.3.2.3.4.

31.2.3.2.3.1.4 System Resources.

Scheduling Coordinators may submit bids from System Resources for participation in the Day-Ahead Markets as set forth in Section 31.2.3.2.3.3.2.

31.2.3.2.3.1.5. System Units.

Scheduling Coordinators may submit bids for System Units in the Day-Ahead Markets as set forth in Section 31.2.3.2.3.3.3.

31.2.3.2.3.2 Default Data Requirements.

The ISO will treat the information provided to the ISO in accordance with this Section 31.2.3.2.3.2 as confidential and will apply the procedures in Section 20.3.4 of this ISO Tariff with regard to requests for disclosure of such information. Scheduling Coordinators for Generating Units and Capacity Resources shall submit operating constraint information to the ISO in the form specified in the Schedules and Bids Protocol Section 2.4 and other operating characteristics as the ISO may determine from time to time. Scheduling Coordinators must file periodic updates of this information at the direction of FERC or the ISO.

31.2.3.2.3.3. Structure of Bids.

Scheduling Coordinators shall submit three-part bids to the Day-Ahead Market in the relevant applicable forms as set forth below.

31.2.3.2.3.3.1 Generating Units

31.2.3.2.3.3.1.1 Start-up Cost.

Scheduling Coordinators shall submit a bid of a figure, in dollars, representing the cost of the fuel and auxiliary power consumed by the Generating Unit during start-up. A Scheduling Coordinator's bid shall be less than or equal to a cost-based level determined by the ISO using the information provided in accordance with Section 31.2.3.2.3.2, the proxy figure for natural gas costs posted on the ISO Home Page, if applicable, and the relevant Day-Ahead Locational Marginal Price for the same Hour(s) for the previous weekday or weekend Day (including Holidays), or the ISO shall replace that bid with a default bid.

31.2.3.2.3.3.1.2 Minimum Load Cost.

Scheduling Coordinators shall submit a bid of a figure, in dollars, representing the cost of the fuel consumed each hour by the unit when is operating at its minimum load level. This figure shall be the same for each hour. A Scheduling Coordinator's bid shall be less than or equal to a cost-based level determined by the ISO using the information provided in accordance with Section 31.2.3.2.3.2, a variable operations and maintenance cost of $6.00/MWh and the proxy figure for natural gas costs posted on the ISO Home Page, if applicable, or the ISO shall replace that bid with a default bid.

31.2.3.2.3.3.1.3 Energy bid.

Scheduling Coordinators shall submit a monotonically increasing curve, consisting of no more than 10 segments, representing the energy payment (in $/MW per hour) requested at a particular output over the range from the Generating Unit's lowest stable sustainable output to the Generating Unit's maximum stable sustainable output for each hour. The price for Energy at a given output in the curve bid into the ISO's Real Time Imbalance Energy Market for the same Generating Unit cannot exceed the price for the same output in the Energy curve bid into the

Day-Ahead Markets for the same hour for that capacity awarded by the ISO in the Day-Ahead Market or Residual Unit Commitment Process.

31.2.3.2.3.3.2 System Resources

31.2.3.2.3.3.2.1 **Energy Bid.**

Scheduling Coordinators shall submit a monotonically increasing curve, consisting of no more than 10 segments, representing the energy payment (in $/MW per hour) requested at a particular output over the range from the System Resource's lowest stable sustainable output to the System Resource's maximum stable sustainable output for each hour. The price for Energy at a given output in the curve bid into the ISO's Real Time Imbalance Energy Market for the same System Resource cannot exceed the price for the same output in the Energy curve bid into the Day-Ahead Markets for the same hour for that capacity awarded by the ISO in the Day-Ahead Market or Residual Unit Commitment Process.

31.2.3.2.3.3.2.2.Block bids.

Scheduling Coordinators for System Resources may submit separate bids to provide Energy for a number of contiguous hours. Each such bid shall consist of a monotonically increasing curve, consisting of no more than 10 segments, representing the Energy payment (in $/MW per hour) requested for a given level of output.in dollars per MWh, and the contiguous hours in which the Energy is to be provided. The Energy bid curve must be the same for all hours in the same block of contiguous hours. The Energy bid curve may be different for different contiguous blocks of hours.

31.2.3.2.3.3.3. System Units

31.2.3.2.3.3.3.1 Energy Bid.

Scheduling Coordinators shall submit a monotonically increasing curve, consisting of no more than 10 segments, representing the Energy payment (in $/MW per hour) requested at a particular output over the range from the System Unit's lowest stable sustainable output to the System Unit's maximum stable sustainable output for each hour. The price for Energy at a given output in the curve bid into the ISO's Real Time Imbalance Energy Market for the same System Unit cannot exceed the price for the same output in the Energy curve bid into the Day-Ahead Markets for the same hour for that capacity awarded by the ISO in the Day-Ahead Market or Residual Unit Commitment Process.

31.2.3.2.3.4 Loads

Each Scheduling Coordinator representing a Load Serving Entity shall submit bids indicating the hourly quantity of Energy, in MW, that it will purchase from the Day-Ahead Market for each hour of the following day. These bids shall indicate the quantities to be purchased by point of withdrawal, may include Demand Bids identifying prices at which the Load will voluntarily change these quantities, and shall include any other information specified by the ISO's data templates.

31.2.3.2.3.4.1 Designated Load Aggregation Point

The Load Aggregation Point may be stated as the Load Zone, Customer Aggregation, or bus.

31.2.3.2.3.4.2 Quantity at Load Aggregation Point

Load bids shall state the aggregate quantity (in MWh) of Demand that is expected to be served at each Load Aggregation Point for which a bid has been submitted.

31.2.3.2.3.4.3 Demand Bids

Scheduling Coordinators may specify that Loads will be scheduled in response to Locational Marginal Prices by including a Demand Bid.

31.2.3.2.3.4.4. Participating Loads

Scheduling Coordinators serving Participating Loads under the provisions of Section 2.3.2.8.2 may bid Dispatchable Load consisting of individual or aggregated Load of at least 0.1 MW to the ISO as Non-Spinning Reserve or Supplemental Energy, or utilize Dispatchable Load for self provision of Non-Spinning Reserve. Such bids must meet standards adopted by the ISO and published on the ISO Home Page, including Ancillary Services certification as identified in Section 2.5. Any Dispatchable Load intending to use a back-up generator must obtain, and provide to the ISO, written approval from their local Air Quality Management District. Scheduling Coordinators may additionally submit three-part energy bids in accordance with Schedules and Bids Protocol Section 2.1.2 which consist of the following parts:

31.2.3.2.3.4.4.1 Minimum Curtailment Payment

A figure, in dollars, representing the minimum payment for initiating a curtailment regardless of the quantity curtailed or the duration of the curtailment. Start-up

31.2.3.2.3.4.4.2 Minimum Hourly Payment

A figure, in dollars, representing the minimum payment per hour of curtailment at the lowest MW level stated in the first segment of the energy bid curve set forth in accordance with SBP Section 2.1.2.

31.2.3.2.3.4.4.3 Energy Bid Curve

A monotonically decreasing curve, consisting of no more than ten segments defined by MW and $/MWh values, representing the Locational Marginal Price at which the scheduled Load will voluntarily adjust relative to its Preferred Schedule.

31.2.3.2.3.4.4.4.Additional bid data

Scheduling Coordinators may also include figures representing (a) the time, in minutes, required for curtailment following notification; (b) minimum off time, in hours, stating the minimum number of hours the Dispatchable Load is willing to be curtailed; and (c) maximum off time, in hours, stating the maximum number of hours the Dispatchable Load is willing to be curtailed and other data as set forth in SBP Protocol 2.1.2. Bids may also include a designation as "hourly only" (i.e., not able to make intra-hour changes). The ISO will utilize "hourly only" bids left over from the Hour-Ahead Market to issue pre-dispatch instructions for Imbalance Energy based on the ISO Demand Forecast, subject to the provisions of Section 31.4.2. Bids that include a Minimum Curtailment Payment or Minimum Hourly Payment will remain subject to Dispatch by the ISO after completion of the Day-Ahead and Hour-Ahead Markets regardless of their designation as "hourly only" bids.

31.2.3.2.3.4.5 Default Energy Bids for Congestion Management

As provided in Section 31.2.3.1.4.2, the ISO will add default Energy bids, at a price equal to the Bid Ceiling, to ensure that a Load may be curtailed to the extent necessary for scheduling purposes in the event that inadequate or unusable supply bids are submitted to the ISO to enable the ISO's Congestion Management to resolve Schedules on an economic basis.

31.2.3.2.3.5 Default Bids for Capacity Resources

If a Scheduling Coordinator for an Capacity Resource or a resource required to offer its Available Generation subject to Section 31.2.3.2.2. fails to submit a bid into the Day-Ahead Market, the ISO shall submit a bid on its behalf which consists of the following parts:

31.2.3.2.3.5.1 Generating Units

31.2.3.2.3.5.1.1 Start-up Cost.

The ISO shall submit a bid of a figure, in dollars, representing the cost of the fuel and auxiliary power consumed by the Generating Unit during start-up determined by the ISO using the information provided in accordance with Section 31.2.3.2.3.2., the proxy figure for natural gas costs posted on the ISO Home Page, if applicable, and recent prices in the ISO Real Time Imbalance Energy Market.

31.2.3.2.3.5.1.2.Minimum Load Cost.

The ISO shall submit a bid of a figure, in dollars, representing the cost of the fuel consumed each hour by the unit when is operating at its minimum load level determined by the ISO using the information provided in accordance with Section 31.2.3.2.3.2, a variable operations and maintenance cost of $6.00/MWh and the proxy figure for natural gas costs posted on the ISO Home Page, if applicable. This figure shall be the same for each hour.

31.2.3.2.3.5.1.3 Energy bid.

The ISO shall submit a monotonically increasing curve, consisting of no more than 10 segments, representing the Energy payment (in $/MW per hour) requested at a particular output over the range from the Generating Unit's lowest stable sustainable output to the Generating Unit's maximum stable sustainable output for each hour determined by the ISO using the information provided in accordance with Section 31.2.3.2.3.2, a variable operations and maintenance cost of $6.00/MWh and the proxy figure for natural gas costs posted on the ISO Home Page, if applicable.

31.2.3.2.3.5.1.4 Ancillary Services Bids

The ISO shall submit a bid of $0/MW into all Ancillary Services based on the Generating Unit's physical capabilities, including ramp rate.

31.2.3.2.3.5.2 System Resources that are Capacity Resources

31.2.3.2.3.5.2.1.Energy Bid

The ISO shall submit a bid of $0/MWh for the contracted capacity not already bid or scheduled.

31.2.3.2.3.5.3. System Units that are Capacity Resources

31.2.3.2.3.5.3.1.Energy Bid

The ISO shall submit a bid of $0/MWh over the range from the System Unit's minimum operating level to the System Unit's maximum contracted capacity not already bid or scheduled.

31.2.3.2.3.6 Loads that are Capacity Resources

The ISO shall submit a bid for $0/MWh for the contracted capacity not already bid or scheduled.

31.2.3.2.4 Ancillary Services Bids

Resources certified for Ancillary Services provision may submit additional scheduling and bidding information for Ancillary Services along with their Energy bids as set forth in Schedules and Bids Protocol Section 5.

Generators selected to provide Ancillary Services, except for units providing Non-Spinning Reserve that can start and synchronize to the grid in less than 10 minutes, shall be considered self-committed and shall be scheduled to at least their Minimum Load plus any capacity selected for Regulation Down. Energy and Ancillary Services bids and Schedules shall be validated against the resource's operating limits and ramp rate capability. The ISO shall not award more Ancillary Services Capacity to a resource than the capacity offered for that service. The capacity reservation bid cannot exceed the applicable Bid Caps in accordance with Section 28.1.

31.2.3.2.5 Inter-SC Trades

Inter-SC trades for Energy or Ancillary Services shall not affect the scheduling or the prices of Energy or Ancillary Services. These trades are strictly financial instruments used in Settlements. For this reason, SCUC shall never adjust valid inter-SC trades.

31.2.3.2.5.1 Energy Trades

Inter-SC Energy trades may take place between any pair of Scheduling Coordinators. These trades indicate Energy traded between two SC portfolios at a specified Location Code or Trading Hub. Only one inter-SC Energy trade may be submitted for a given SC pair per Location. Both parties must submit the necessary trade information and that information should be consistent. The required trade information is set forth in SBP Section 2.1.4.

Inter-SC Energy trades shall be validated for consistency: Both trading SCs must submit the trade and the trade must be at the same Location and for the same amount of Energy (considering the sign convention) for each hour of the Trading Day. If the Location and Energy amounts do not match for any given hour, the trade shall be invalid for that hour and will be ignored.

Inter-SC Energy trades that originate from self-committed resources shall be taken into account in the allocation of Unrecovered Commitment Costs in accordance with Section 31.2.3.4.4.4.2.

31.2.3.2.5.2 Ancillary Services Trades

Inter-SC Ancillary Services trades may take place between any pair of Scheduling Coordinators within one Ancillary Services Region, as published prior to the Day-Ahead market in accordance with Scheduling Protocol Section 3.2.2. Only one inter-SC Ancillary Services trade may be submitted for a given SC pair per Ancillary Service per Location. Both parties must submit the necessary trade information and that information must be consistent. The required trade information is set forth in SBP Section 2.1.5.

Inter-SC Ancillary Services trades shall be validated for consistency: Both trading SCs must submit the trade and the trade must be at the same Location and for the same amount of capacity (considering the sign convention) for each hour of the Trading Day. If the Location and capacity amounts do not match for any given hour, the trade shall be invalid for that hour and will be ignored.

Inter-SC Ancillary Services trades shall be considered transfers of Ancillary Services requirements between SCs and they will be taken into account in the allocation of Ancillary Services procurement costs in accordance with Section 31.2.3.4.2.6.

31.2.3.2.6 Existing Contract Scheduling

Existing Contracts shall be scheduled as balanced Energy Schedules with no Energy bids between Supply and Demand resources designated as Existing Contracts Sources and Sinks, respectively. Energy Schedules from Existing Contracts Sources and Sinks shall indicate the Schedule portions that are associated with Existing Contracts Schedules. No Energy bids shall be submitted for the Existing Contracts Schedule portions. The Existing Contracts Schedules shall be validated against predetermined Source-Sink patterns and network use published prior to the Day-Ahead market in accordance with Section 31.2.1.7.

Existing Contracts Schedules shall be given the highest scheduling priority in the Day-Ahead Market in accordance with Section 31.2.3.1.4.2.1. Existing Contracts Schedules shall be exempt from the Energy Settlement, i.e., the scheduled Energy from Existing Contracts Sources or Sinks will not be paid or charged, respectively. Therefore, Existing Contracts Schedules shall not be charged Congestion and Transmission Loss charges. However, Existing Contracts Schedules that fail validation shall be charged Congestion and Transmission Loss charges as applicable.

Unscheduled transmission capacity under Existing Contracts shall be reserved in the Day-Ahead Market by appropriately reducing the ATC of the network to allow for Existing Contracts Schedule deviations in the Hour-Ahead Market. The remaining ATC on certain transmission paths shall be published prior to the Day-Ahead Market in accordance with Sections 31.1.3 and 31.2.1.4.

31.2.3.2.7 Firm Transmission Right Scheduling

Point-To-Point (PTP) Firm Transmission Rights (FTRs) optionally provide FTR Holders scheduling priority for balanced schedules with the same Ssource and Sink associated with the FTR in the Day-Ahead Market, in accordance with Sections 31.2.3.1.4.2.2. and Section 9.1.1. For this purpose, PTP FTRs shall be scheduled as balanced Energy Schedules with no Energy Bids between Supply and Demand resources designated as FTR Sources and Sinks, respectively. Energy Schedules with FTR Sources and Sinks shall indicate the Schedule portions that are associated with FTR Schedules. No Energy Bids should be submitted for the FTR Schedule portions. The FTR Schedules shall be validated against the scheduling rights assigned by the corresponding FTR Holders to the SCs submitting these Schedules.

PTP FTR Schedules shall be given the second highest scheduling priority in the Day-Ahead Market after Existing Contracts Schedules. However, FTR Schedules that fail validation shall lose their scheduling priority. Energy and capacity from Sources and Sinks associated with FTR Schedules shall be settled in accordance with Section 31.2.3.4.1.

31.2.3.2.8 Wheeling Through Scheduling

Wheeling Through Schedules shall be balanced Energy Schedules between two System Resources at different Scheduling Points, an import and an export, scheduled separately, but identified as wheeling schedules with the same Preferred Schedule and interchange identification.

Wheeling Through Schedules shall specify in their NERC tags valid resource Sources and Sinks in different Control Areas to prevent circulating Energy Schedules. SCUC shall keep the import and export Energy Schedules of Wheeling Through Schedules in balance. These import and export Energy Schedules shall be settled in accordance with Section 31.2.3.4.1, therefore, Wheeling Through Schedules will be charged (or paid) for contributing to (or relieving)

Congestion and Transmission Losses. In order for a Wheeling Through Schedule to be compensated for relieving Congestion the Wheeling Through Schedule must identify the physical resource and the resource's Control Area for both the Source and Sink. A Wheeling Through Schedule with Sources and Sinks in the same Control Area are will not be compensated for relieving Congestion.

31.2.3.3 Market Power Mitigation

Any bid submitted to the ISO Markets or to the Residual Unit Commitment Process shall be subject to the Damage Control Bid Cap as set forth in Section 28.1 and to the Mitigation Measures set forth in Appendix A to the Market Monitoring and Information Protocol.

31.2.3.4 Day-Ahead Settlements

For each hour of a given Trading Day, the ISO will settle with Scheduling Coordinators for their final Day-Ahead Energy and Ancillary Services Schedules.

31.2.3.4.1 Day-Ahead Energy Settlement

The ISO shall calculate the Day-Ahead Locational Marginal Prices (LMPs) for each network node and Load aggregation as described in Section 31.2.3.2.1. Each Scheduling Coordinator that bids a resource into the ISO Day-Ahead Market and is scheduled in the Unit Commitment Service to sell or buy Energy in the Day-Ahead Market will be paid or charged, respectively, the product of (a) the Day-Ahead hourly LMP at the resource's Location, which can be a Load Aggregation Point; and (b) the hourly Final Day-Ahead Energy Schedule. The ISO shall publish the Day-Ahead LMPs for each hour of the Trading Day.

31.2.3.4.2 Day Ahead Ancillary Services Capacity Payment

The ISO procures Ancillary Services capacity simultaneously with Energy in the Day-Ahead Market. Resources are selected to provide Ancillary Services using an opportunity cost approach that considers a given resource's Energy Bid. The opportunity cost of the resource is determined as the positive difference between the LMP at the given resource's Location and the Energy Bid of the given resource at the its Final Day-Ahead Energy Schedule. In addition, the ISO allows suppliers to submit capacity reservation bids for Ancillary Services in addition to their Energy Bid curves. The resource's capacity reservation bid is considered as an adder to the opportunity cost determined from the submitted Energy bid. The hourly Ancillary Service Marginal Price (ASMP) for each Ancillary Service and region is the highest total price (opportunity cost plus capacity reservation) for each service selected in that region and hour. Ancillary Services that are provided by resources outside the ISO grid are allocated a portion of transmission capacity through the Congestion Management procedure so that the service can be delivered as Energy in real-time if Dispatched.

31.2.3.4.2.1. Payments to Suppliers for Regulation Service

Scheduling Coordinators for resources supplying Regulation Up or Down to the ISO shall receive a capacity payment that is calculated as the product of the ASMP for Regulation Up or Down, respectively, in the Ancillary Services Region where the resource resides, and the awarded regulating capacity.

31.2.3.4.2.2. Payments to Suppliers for Operating Reserves

Scheduling Coordinators for resources supplying Operating Reserves, i.e., Spinning and Non-Spinning Reserve, shall receive capacity payment(s) for each MW of reserve that they provide as requested by the ISO. A capacity payment shall be determined separately for Spinning Reserve and Non-Spinning Reserve. The ISO shall pay for each category a capacity payment calculated as the product of: (a) the ASMP for the applicable reserve and Ancillary Service Region; and (b) the reserve capacity to be provided by the resource, as selected by the ISO..

31.2.3.4.2.3. Congestion Charges to Imports Providing Ancillary Services.

Imports providing Ancillary Services at Scheduling Points interconnected through inter-ties that are Congested in the import direction shall be explicitly charged for the marginal cost of reserving transmission capacity on the Congested inter-tie to accommodate the associated Ancillary Services capacity. The Congestion charge shall be equal to the product of the Ancillary Services capacity and the shadow price of the Congested inter-tie as calculated by SCUC.

31.2.3.4.2.4. Payments to Suppliers of Reactive Supply and Voltage Support Service

Scheduling Coordinators for resources supplying Voltage Support Service shall receive a Voltage Support Service payment in accordance with the criteria and formula in Settlements And Billing Protocol Appendix G.

31.2.3.4.2.5 Payments to Generators for Black Start Capability

Black Start Capability providers shall receive a payment for Black Start Capability as set forth in Settlements And Billing Protocol Appendix G.

31.2.3.4.2.6. Allocation of Ancillary Services Costs

Ancillary Services costs shall be allocated as set forth in SABP Appendix C.

31.2.3.4.3 Firm Transmission Right Holder Payment/Charge

Firm Transmission Rights payments and charges shall be allocated in accordance with Section 9.4.2.

31.2.3.4.4. Unit Commitment Cost Compensation

Resources that are not self-scheduled in the Day-Ahead but committed by the ISO prior to the closing of the Day-Ahead Market shall be compensated for start-up and minimum load costs that remain unrecovered from market revenues from the Day-Ahead and Hour-Ahead Energy and Ancillary Services Markets and Real-Time Imbalance Energy Market during the same hours.

31.2.3.4.4.1. Generating Units

31.2.3.4.4.1.1. Unit Commitment Cost Payment to Generating Units

The ISO shall pay Generating Units selected by the ISO in the Unit Commitment Service their positive Unrecovered Commitment Costs.

31.2.3.4.4.1.1.1.Unrecovered Commitment Costs

Unrecovered Commitment Costs shall be the Allocated Start-Up Costs plus the sum, for all hours in the ISO Commitment Period, of the Hourly Minimum Load Cost Deficiencies, less the sum, for all hours in the ISO Commitment Period, of the Hourly Market Net Revenue.

31.2.3.4.4.1.1.2 Allocated Start-Up Costs

Allocated Start-Up Costs shall be the product of the Unit's Start-Up Cost and a fraction equal to the number of Qualifying Hours divided by the number of the hours in the ISO Commitment Period.

31.2.3.4.4.1.1.2.1. Eligibility to be paid Allocated Start-Up Costs

A Generating Unit shall be eligible to be paid Allocated Start-Up Costs for the Trading Day if 1) the Unit has no Self-Commitment Periods for that Trading Day, and 2) the Unit actually starts up.

31.2.3.4.4.1.1.2.2. Commitment Period

The Commitment Period begins when the Generating Unit is synchronized to the grid and ends when the Generating Unit is de-synchronized from the grid.

31.2.3.4.4.1.1.2.3. ISO Commitment Period

The ISO Commitment Period begins when the Generating Unit is synchronized in response to the ISO selecting that unit in the Unit Commitment Process and ends at the later of 1) when the ISO notifies the Scheduling Coordinator that the unit is no longer required; 2) the unit is forced out of service; and 3) the time that is the time the Generating Unit is synchronized plus the Generating Unit's minimum run time, except the ISO Commitment Period shall not extend beyond the end of a Trading Day.

31.2.3.4.4.1.1.2.4. Self-Commitment Period

The Self-Commitment Period is that portion of a Commitment Period when the Scheduling Coordinator for that Generating Unit submits Energy schedules or is awarded Ancillary Services schedules. Self-Commitment Periods shall also include periods where the Scheduling Coordinator does not submit Energy Schedules or is awarded Ancillary Services Schedules for the Generating Unit if the Generating Unit must remain on in those periods in response to the Scheduling Coordinator having submitted Energy Schedules or having been awarded Ancillary Service Schedules to satisfy the Generating Unit's minimum run time or minimum off time.

31.2.3.4.4.1.1.2.5. Qualifying Hour

A Qualifying Hour shall be an Hour in the ISO Commitment Period in which 1) the Generating Unit is not awarded or does not self-provide an Hour-Ahead Ancillary Services schedule, and 2) the ISO does not Dispatch the Generating Unit in accordance with its RMR Contract.

31.2.3.4.4.1.1.3.Hourly Minimum Load Cost Deficiency

The Hourly Minimum Load Cost Deficiency for each hour shall be the number that is the greater of zero and the unit's Minimum Load Cost less the product of the unit's minimum load level and the relevant Locational Marginal Price.

31.2.3.4.4.1.1.3.1. Minimum Load Cost

The Minimum Load Cost shall be the sum of 1) the product of a) the unit's average heat rate at minimum load; b) the proxy figure for natural gas costs posted on the ISO Home Page and c) the unit's minimum load; and 2) the unit's minimum load and $6.00.

31.2.3.4.4.1.1.4 Hourly Market Net Revenue

The Hourly Market Net Revenue for each hour shall be the product of 1) the number that is the relevant Locational Marginal Price less the Imputed Cost and 2) the number that is the difference between the Final Day-Ahead Energy Schedule and the Generating Unit's minimum load level.

31.2.3.4.4.1.1.4.1. Imputed Cost for Gas-Fired Generating Units and System Units

The Imputed Cost for Gas-Fired Generating Units and System Units shall be the sum of 1) the product of a) the unit's average heat rate at the Final Day-Ahead Energy Schedule; b) the Final Day-Ahead Energy Schedule; and c) the proxy figure for natural gas costs posted on the ISO Home Page; and 2) $6.00.

31.2.3.4.4.1.1.4.2. Imputed Cost for Non-Gas-Fired Generating Units and System Units

The Imputed Cost for Non-Gas-Fired Generating Units and System Units shall be the cost at the Final Day-Ahead Energy Schedule as calculated using the data provided in accordance with Section 31.2.3.2.3.2.

31.2.3.4.4.1.2 Payment for Terminated Start-up

If 1) the ISO selects a Generating Unit in the Unit Commitment process 2) the ISO instructs the unit to start-up, and 3) the start-up is terminated before the unit is synchronized, the ISO shall pay the Scheduling Coordinator for that Generating Unit a start-up payment equal to the start-up cost in the Generating Unit's bid multiplied by a fraction equal to the number of hours the unit was in start-up when the start-up was terminated divided by the number of hours the unit normally takes to start-up (as provided in accordance with 31.2.3.2.3.2.3), except that in no case shall this payment exceed the start-up cost calculated in accordance with 31.2.3.2.3.3.1.1.

31.2.3.4.4.2 System Resources.

System Resources have no Unit Commitment Costs in the Day-Ahead Market unless they have provided data to the ISO to be considered as a Generating Unit, in which case they shall be treated as set forth in Sections 31.2.3.4.4.1.1.4.1 or 31.2.3.4.4.1.1.4.2, as applicable.

31.2.3.4.4.3 Dispatchable Load

31.2.3.4.4.3.1. Minimum Curtailment Payment

If the ISO selects Dispatchable Load in the Unit Commitment process, the ISO shall pay the Scheduling Coordinator for that Dispatchable Load the amount of the minimum curtailment payment in that Dispatchable Load's bid provided the Dispatchable Load successfully reduces its Demand from its Final Hour Ahead Schedule at the time the ISO requests curtailment. The Minimum Curtailment Payment shall be paid subject to the same provisions as start-up costs under Section 31.2.3.4.4.1.1.2.

31.2.3.4.4.3.2. Minimum Hourly Payment

The Minimum Hourly Payment shall be paid subject to the same provisions as Minimum Load Costs under Section 31.2.3.4.4.1.1.3.

31.2.3.4.4.4. Unit Commitment Cost Allocation

31.2.3.4.4.4.1. Total Hourly Unit Commitment Cost.

The Total Hourly Unit Commitment Cost for each hour shall be the sum of 1) the Hourly Generating Unit Commitment Costs, 2) the Hourly System Resource Commitment Costs, 3) the Hourly Curtailable Demand Commitment Costs, and 4) Hourly Terminated Start-Up Costs.

31.2.3.4.4.4.1.1 The Hourly Generating Unit Commitment Costs

The Hourly Generating Unit Commitment Costs shall be equal to the sum, for all Generating Units selected in the Unit Commitment process for that hour, of the Generating Unit's Unrecovered Commitment Costs divided by the number of hours in each Generating Unit's ISO Commitment Period.

31.2.3.4.4.4.1.2 The Hourly System Resource Costs

The Hourly System Resource Costs shall be equal to the sum, for all System Resources selected by the ISO for that hour, of the System Resource's System Resource Uplift Costs divided by the number of contiguous hours the System Resource was scheduled by the ISO in accordance with the System Resource's bid in the Unit Commitment process.

31.2.3.4.4.4.1.3.The Hourly Curtailable Demand Commitment Costs

The Hourly Curtailable Demand Commitment Costs shall be equal to the sum, for all Dispatchable Loads scheduled by the ISO in that hour, of the Dispatchable Load's Hourly Curtailable Demand Commitment Costs divided by the number of hours the Dispatchable Load was curtailed by the ISO.

31.2.3.4.4.4.1.4.The Hourly Terminated Start-Up Costs

The Hourly Terminated Start-Up Costs shall be the sum, for all Generating Units selected in the Unit Commitment process for that hour, of the Terminated Start-Up Payments made in accordance with Section 2.2.6.4.1.2 divided by the number of hours the unit was in start-up when the start-up was terminated.

31.2.3.4.4.4.2 Allocation of Total Hourly Unit Commitment Cost

The Total Hourly Unit Commitment Cost shall be allocated each hour to all Scheduling Coordinators whose Day-Ahead scheduled Demand is in excess of Day-Ahead scheduled Supply. Energy trades that are submitted to the ISO by Scheduling Coordinators will be included in determination of a given SC's excess scheduled Demand.

31.2.4 Residual Unit Commitment Process

The Residual Unit Commitment Process is set forth in Section 5.12.

31.3 Hour-Ahead Market

The Hour-Ahead Market provides the opportunity for Scheduling Coordinators (SCs) to submit changes to their Final Day-Ahead Schedules. Schedule changes can be made in response to revised Demand Forecasts, changes in unit availability, transmission outages, or trades executed after the close of the Day-Ahead Market. The Hour-Ahead Market timeline is set forth in Appendix C. All Day-Ahead bidding, Unit Commitment, scheduling and Settlement functions shall be performed as they are performed in the Day-Ahead Market as set forth in Section 31.2.3, with the following exceptions:

31.3.1 Participation

31.3.1.1. Capacity Resources.

Scheduling Coordinators must submit bids from Capacity Resources in the Hour-Ahead Market as set forth in Section 31.2.3.2.3.3.1.

31.3.1.2. Generating Units.

Scheduling Coordinators may bid all Generating Units in the Hour-Ahead Markets as set forth in Section 31.2.3.2.3.3.1.

31.3.1.3. Load

Scheduling Coordinators may bid Load in the Hour-Ahead Markets as set forth in Section 31.2.3.2.3.4.

31.3.1.4 System Resources

Scheduling Coordinators may bid System Resources in the Hour-Ahead Markets as set forth in Section 31.2.3.2.3.3.2.

31.3.1.5 System Units

Scheduling Coordinators may bid System Units in the Hour-Ahead Markets as set forth in Section 31.2.3.2.3.3.3.

31.3.2 Time Horizon for the Hour-Ahead Market

The time horizon for the Hour-Ahead SCUC shall be up to five hours. Units with start-up times longer than four hours will be precluded from selection in the Hour-Ahead Market. The SCUC shall consider all schedules and bids submitted to the Hour-Ahead Market for the next five Hours (with appropriate adjustments for Demand Forecast changes) to provide for continuity. The optimal SCUC Schedules for the next hour shall constitute the Final Hour-Ahead Energy and Ancillary Services Schedules for that hour. The ISO shall publish only Final Hour-Ahead Schedules for the next hour. The resource shall be required to provide the capacity and deliver the Energy in the published Final Hour-Ahead Schedule as set forth in Section 2.3.1.2. The optimal Schedules for the four hours beyond the next hour will be for the ISO's advisory use only.

31.3.3. Limitations on bid prices

The section of the Energy Bid curve associated with a Final Day-Ahead Schedule for Energy cannot be changed in the Hour-Ahead Market. The section of the Energy Bid curve associated with Day-Ahead Ancillary Services capacity selected or capacity selected in the Day-Ahead Residual Unit Commitment Process cannot be increased in the Hour-Ahead Market. The section of the Energy Bid curve associated with any capacity not selected in the Day-Ahead Market or in the Day-Ahead Residual Unit Commitment Process may be increased or decreased in the Hour-Ahead Market a) subject to the limits in Section 28 and b) as long as the entire Energy Bid curve remains monotonically increasing (for a Supply resource) or monotonically decreasing (for a Demand resource).

31.3.4. Ancillary Services Buy-Back

A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, or Non-Spinning Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, System Unit, Dispatchable Load, or System Resource successfully bid in a Day-Ahead Ancillary Service

Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be the maximum of the Ancillary Service Marginal Price in the Hour-Ahead Market or Day-Ahead Market for the same Settlement Period for the Ancillary Service capacity concerned.

31.3.5 Hour-Ahead Settlements

31.3.5.1. Hour-Ahead Unit Commitment Cost Compensation

Resources that are not self-scheduled in the Hour-Ahead but committed by the ISO prior to the closing of the Hour-Ahead Market shall be compensated for start-up and minimum load costs that remain unrecovered from market revenues from the Hour-Ahead Energy and Ancillary Services Markets and Real-Time Imbalance Energy Market during the same hours.

31.3.5.2 Congestion Deficit Due to ATC Reduction

When a given network branch, or more generally a transmission interface, is Congested in the Hour-Ahead Market and its ATC in the direction of congestion is reduced in the Hour-Ahead Market due to a derate to a level lower than the net final Day-Ahead scheduled flow on that interface and direction, the Hour-Ahead Congestion Revenue on that interface will be negative (the negative scheduled flow deviation multiplied by the Hour-Ahead shadow price on the interface). The Congestion deficit shall be first reduced by a debit to the relevant monthly FTR Balancing Account and the remaining deficit shall be allocated to Scheduling Coordinators in proportion to their final Day-Ahead scheduled flow on the interface in the direction of Hour-Ahead Congestion.

The debit to the relevant monthly FTR Balancing Account shall be equal to the product of the negative Hour-Ahead scheduled flow deviation and the lower of the Day-Ahead or Hour-Ahead shadow price on the interface in the direction of Hour-Ahead Congestion (the former will be zero if there is no Day-Ahead Congestion). The debit to the relevant monthly FTR Balancing Account shall be made irrespective of the balance in the account, i.e., the account may be overdrawn.

The remaining Congestion deficit after debiting the relevant monthly FTR Balancing Account, shall be allocated to all Scheduling Coordinators in proportion to their final Day-Ahead scheduled flow on the interface in the direction of Hour-Ahead Congestion. The final Day-Ahead scheduled flow shall be determined using the Power Transfer Distribution Factors (PTDFs) of the Full Network Model used for the relevant hour in the Day-Ahead Market and that hour's Final

Day-Ahead Energy Schedules. The PTDFs shall be calculated using a distributed load slack reference and shall be published on the ISO OASIS two (2) hours prior to the Hour-Ahead market.

If the Hour-Ahead ATC reduction is on a Congested inter-tie in the import direction, any transmission capacity reservation on that inter-tie for Day-Ahead Ancillary Services imports shall be considered as Day-Ahead scheduled flow on that inter-tie for purposes of any associated Congestion deficit allocation.

31.3.6 Hour-Ahead Residual Unit Commitment

The Hour-Ahead Residual Unit Commitment Process allows the ISO to acquire additional resources to meet the Demand, including any Operating Reserve or other capacity requirements projected by the ISO for the next operating hour and subsequent four hours of the Trading Day. This Hour-Ahead Residual Unit Commitment Process may be necessary if units committed in the Day-Ahead Residual Unit Commitment Process fail to start, or the Hour-Ahead Demand Forecast exceeds the Day-Ahead Demand Forecast. The Residual Unit Commitment Process is set forth in Section 5.12. The requirements for participation, data submittal, procurement target and objective function remain the same as in Section 5.12, except only units with start-up times less than or equal to four hours will be considered.

31.3.6.1 Allocation of Hour-Ahead Residual Unit Commitment Process Charges.

Hour-Ahead Residual Unit Commitment costs shall be allocated as set forth in 5.12.8, except using Final Hour-Ahead Schedules instead of Final Day-Ahead Schedules.

31.4 Real-Time Market

31.4.1. Bidding Requirements

31.4.1.1. 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 Dispatch Protocol 8.6.3, and (b) the Security Constrained Economic Dispatch (10-minute Imbalance Energy market). The Energy Bid shall be a staircase price ($/MWh) versus quantity (MW) curve of up to 10 segments. 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.

31.4.1.2. Energy Bid Submission

All Energy Bids for the Imbalance Energy Market must first be bid into the Hour-Ahead Market. Bids from System Resources may be withdrawn before they are Dispatched by the ISO due to physical conditions beyond the supplier's control and subject to the ISO's approval, however, once these bids are Dispatched by the ISO they cannot be withdrawn and become binding obligations subject to the Uninstructed Deviation Penalties set forth in Section 11.2.4.1.2. The ISO shall not consider bids from Generating Units that report Forced Outages to the ISO in accordance with Section 2.3.3.9.2 for the duration of the Forced Outage. The unused portions of Energy Bids submitted to the Hour-Ahead Market shall be bids into the Imbalance Energy Market. Scheduling Coordinators shall have no opportunity to revise these Energy Bids before the Imbalance Energy Market. Energy Bids for use in the Hour-Ahead Market, for the Hourly Pre-Dispatch set forth in DP 8.6.3(j) and for the SCED shall be submitted no later than 60 minutes prior to the operating hour, for first use in the Hour-Ahead Market. In the absence of submitted bids, default bids will be used for Capacity Resources. Resources not designated as Capacity Resources may voluntarily submit Energy Bids. Energy Bids submitted to the Imbalance Energy Market for System Resources and Dispatchable Load must identify if the associated resource can be re-dispatched within the hour or can only be dispatched for the entire hour.

31.4.1.3. Real Time Energy Bid Partition

Capacity selected in the Residual Unit Commitment Process will be associated with the lowest-priced portion of the Energy Bid curve above the Final Hour-Ahead Schedule. The portion of the Energy Bid that corresponds to the upper portion of the resource's operating range, shall be allocated to any awarded or self-provided Ancillary Services in the following order from higher to lower capacity: (a) Regulation Up; (b) Spinning Reserve; and (c) Non-Spinning Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid (i.e. that portion between capacity selected in the Residual Unit Commitment Process and capacity committed to provide Ancillary Services) shall constitute a bid to provide Supplemental Energy.

31.4.1.4 Participating Resources

The ISO shall certify Resources that can respond to real-time Dispatch Instructions within a Dispatch Interval. Such resources may only participate in the Imbalance Energy Market. Resources that can respond only to Hourly Pre-Dispatch instructions shall not participate in the Imbalance Energy Market but may participate in the Hourly Pre-Dispatch. Resources that cannot respond to 10-minute Dispatch Instructions or to Hourly Pre-Dispatch instructions shall not participate in either the Imbalance Energy Market or the Hourly Pre-Dispatch.

31.4.2 Hourly Pre-Dispatch

The Hourly Pre-Dispatch shall take place approximately 30 minutes prior to the beginning of the operating hour. The objective of the Hourly Pre-Dispatch is to Dispatch resources at least cost to supply Imbalance Energy or to Dispatch Demand on an hourly basis to meet some of the Hour's forecasted Imbalance Energy requirement. The portion of the hour's forecasted Imbalance Energy requirement met by Hourly Pre-Dispatch shall be determined by an optimization methodology that will minimize the overall cost of Imbalance Energy procured through Hourly Pre-Dispatch for the entire hour and through Security Constrained Economic Dispatch (SCED) for each Dispatch Interval within the hour. The optimization methodology will estimate the Imbalance Energy cost for each Dispatch Interval by applying the SCED methodology to Dispatch resources in each Dispatch Interval to meet forecasted Imbalance Energy requirements not met by Energy Dispatched in the Hourly Pre-Dispatch and Residual Unit Commitment Process. The optimization methodology for the Hourly Pre-Dispatch is described in detail in Dispatch Protocol Appendix A.

31.4.2.1. Eligibility

Resources eligible for Hourly Pre-Dispatch are resources that the ISO determines are unable to comply with the interval Dispatch requirements of the Imbalance Energy Market. The ISO shall pre-Dispatch Energy in the Hourly Pre-Dispatch process in addition to the Minimum Load Energy and Energy from System Resources pre-dispatched during the Day-Ahead and Hour-Ahead Residual Unit Commitment Processes.

31.4.2.2. Market Power Mitigation

Any bid submitted to the ISO Imbalance Energy Market and Hourly Pre-Dispatch shall be subject to a) the Damage Control Bid Cap set forth in Section 28.1 b) the Mitigation Measures set forth in Appendix A to the Market Monitoring and Information Protocol, and c) the Local Market Power Mitigation measures set forth in Section 31.2.3.1.4.5.

31.4.2.3. Pre-Dispatched Energy Settlement

Bids selected for Hourly Pre-Dispatch shall be pre-Dispatched for the entire hour. Pre-Dispatched resources must ramp in and out with a scheduling ramp as set forth in SABP Appendix D. Hourly pre-Dispatched bids shall not be eligible to set any of the Dispatch Interval Locational Marginal Prices during the hour. Positive Instructed pre-Dispatched Energy shall be paid the higher of their Energy Bid price or the Energy-weighted average of the Dispatch Interval Locational Marginal Prices for that Location during the hour consistent with their scheduling

ramp. Negative Instructed pre-Dispatched Energy shall be charged the lower of the Energy Bid price or the Energy-weighted average of the Dispatch Interval Locational Marginal Prices for that Location during the hour consistent with their scheduling ramp. Energy from Hourly Pre-dispatched Bids shall be deemed delivered; any deviations shall be settled as Uninstructed Imbalance Energy at the applicable Dispatch Interval Locational Marginal Prices and may be subject to Uninstructed Deviation Penalties in accordance with Section 11.2.4.1.2.

31.4.3. Interval Dispatch

31.4.3.1. Imbalance Energy Requirement Calculation

The following items shall be inputs to the ISO's calculations of its Imbalance Energy requirements:

31.4.3.1.1. Short-Term Demand Forecast

The ISO shall forecast the Imbalance Energy requirement through the following hour based on historical Demand patterns and the actual Demand. This short-term Demand forecast shall be one input to the ISO-calculated Imbalance Energy requirements. The ISO shall prepare the short-term Demand forecast at the UDC level and distribute Demand to individual buses based on Load Distribution Factors consistent with Section 31.2.3.2.1.1.2.

31.4.3.1.2 Regulating Unit Offset

Regulating units respond to Area Control Error (ACE) on a continual basis to maintain system frequency and net scheduled Control Area interchange. As a result, the net difference between the regulating resources' actual operating points and their Dispatch Operating Points (the "Regulating Unit Offset") is an indication of the quantity of system imbalance.

31.4.3.1.3. Input Based on System Conditions

The ISO shall provide an input to the calculated system Imbalance Energy needs based on system conditions in addition to the inputs already set forth in Sections 31.4.3.1.1 and 31.4.3.1.2

31.4.3.2. Real-Time Dispatch

31.4.3.2.1. State Estimator

Power system operations, including, but not limited to, the determination of the least costly means of serving load, depend upon the availability of a complete and consistent representation of generating unit outputs, loads, and power flows on the network. To calculate Locational Marginal Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the ISO Control Area and the WSCC Interconnection by using the most recent power flow solution produced by the State Estimator, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available real-time metering information, information regarding the current status of lines, generating units, transformers, and other equipment, Load Distribution Factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which real-time information is unavailable. The ISO shall obtain a State Estimator solution at least every ten minutes, which shall provide the megawatt output of generators and the loads at busses in the ISO Control Area and ISO Control Area, transmission line losses, and actual flows or loadings on constrained transmission facilities. External transactions between ISO and other Control Areas shall be included as the real time inter-Control Area Schedules implemented by the ISO schedulers. External transactions shall be represented at their Scheduling Points.

31.4.3.2.2. Imbalance Energy Procurement

The ISO shall Dispatch Generating Units, System Units, Dispatchable Loads and System Resources to meet its Imbalance Energy requirements and eliminate any Price Overlap between incremental and decremental portions of Energy Bids (relative to the Final Hour-Ahead Schedule) at least cost. All Imbalance Energy procurement, including Energy economically Dispatched to resolve Price Overlap between incremental and decremental Energy Bid portions, shall be Dispatched subject to network constraints as described in Section 31.4.3.2.3.

31.4.3.2.2.1. Security Constrained Economic Dispatch

The ISO shall economically Dispatch, subject to network and ramp rate constraints, Generating Units, Dispatchable Loads, System Units and System Resources that effectively 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 2.5.22.3, subject to network constraints that actually exist and to prevent network constraints from developing. The Security Constrained Economic Dispatch program shall produce explicit resource-specific recommended Dispatch Instructions, which the ISO shall communicate to the Scheduling Coordinators responsible for such resources. The ISO shall calculate, account for and settle Imbalance Energy for each Dispatch Interval for the relevant Location within the ISO Controlled Grid.

31.4.3.2.3. Congestion Management

31.4.3.2.3.1. Modeling

The ISO will utilize the same Full Network Model as used in the Day-Ahead and Hour-Ahead Markets. The Full Network Model used in real-time will reflect all real-time network configurations and constraints as determined from the State Estimator as described in Section 31.4.3.2.1.

31.4.3.2.3.2. Default Energy Bids

The default Energy Bids the ISO inserted in the Hour-Ahead Market in accordance with Section 31.2.3.2.3.4.5 shall be available for use in real-time. The default Energy Bids for non-Dispatchable Demand shall be inserted for actual Demand as estimated by the State Estimator instead of scheduled Demand. Through the use of control priorities, however, non-Dispatchable Demand will only be reduced in the Imbalance Energy Market for pricing purposes in the case where all other physical resources have been fully Dispatched. If all physical resources have been fully Dispatched to relieve a real-time constraint, and the constraint remains, the ISO will take emergency action as set forth in Section 2.3.2.2.

31.4.3.2.4 Locational Pricing

Locational Marginal Prices for Imbalance Energy in each Dispatch Interval shall be determined by the most recent Security Constrained Economic Dispatch prior to the end of that Dispatch Interval. LMPs at Trading Hubs and Load aggregation points shall be calculated as the weighted average of the LMPs at all underlying network nodes using the relevant Load Distribution factors (LDFs).

31.4.3.2.5. Exceptional Dispatch

The ISO may Dispatch resources in addition to resources dispatched by SCED. This Dispatch may be necessary to perform Ancillary Services testing, to address Overgeneration, Contingencies, Loop Flows, Nomogram violations, emergency conditions, or any other threats to System Reliability that cannot be addressed by SCED due to modeling limitations, or insufficient or inaccurate data input. Exceptional Dispatch Instructions shall be settled as set forth in Section 31.4.3.4.4 or Section 11.2.4.2, as applicable. Exceptional Dispatch shall not include Dispatch Instructions given to RMR Units under the terms of the RMR Contract. Exceptional Dispatch shall not set any Dispatch Interval Locational Marginal Price.

31.4.3.2.6 Contingency Dispatch

Capacity providing Operating Reserves flagged for contingency use only shall not be dispatched by SCED for Imbalance Energy requirements. SCED will Dispatch such capacity along with all other capacity Dispatched following a contingency.

31.4.3.2.7 Emergency ActionsAll emergency action shall be implemented consistent with Section 2.3.2.2, Protocols and ISO operating procedures.

31.4.3.3. Dispatch Instructions

All Dispatch Instructions, including Exceptional Dispatch Instructions, shall be binding obligations the ISO shall deem delivered. Deviation from Dispatch Instructions shall result in Uninstructed Imbalance Energy, which may be subject to penalties in accordance with Section 11.2.4.1.2. Where possible, the ISO shall communicate Dispatch Instructions to the Scheduling Coordinator responsible for scheduling and Dispatching the resource electronically. All Scheduling Coordinators responsible for responding to Dispatch Instructions must have the ability to receive electronic Dispatch Instructions from the ISO.

31.4.3.4. Imbalance Energy Settlement

Each Dispatch Interval the ISO shall calculate, account for and settle Imbalance Energy at each Location within the ISO Controlled Grid. Imbalance Energy shall be calculated for each Dispatch Interval as the difference between the Metered Quantity and the Final Hour-Ahead Scheduled energy of a given Location. Imbalance Energy shall be settled as either Instructed Imbalance Energy or Uninstructed Imbalance Energy. Any measured deviation from the operating level defined by the Final Hour-Ahead Energy Schedule augmented by ISO Dispatch Instructions shall be settled as Uninstructed Imbalance Energy. All Transmission Losses associated with Imbalance Energy are accounted for in the Dispatch Interval Locational Marginal Prices and are not explicitly settled. SABP Appendix D contains a technical description of the Imbalance Energy Settlement.

31.4.3.4.1 Instructed Energy Settlement

Instructed Energy, i.e., Imbalance Energy produced or consumed in a given Dispatch Interval as the result of responding to Dispatch Instructions, which are deemed delivered, shall be paid if positive, or charged if negative, the LMP at the relevant Location, during that Dispatch Interval, as determined in accordance with Section 31.4.3.2.4.

If a generating unit needs to start-up to respond to a Dispatch Instruction, all Energy produced for its entire minimum up time shall be considered and settled as Instructed Imbalance Energy and the Scheduling Coordinator for that resource shall receive a side payment as set forth in Section 31.4.3.4.4 to guarantee bid price recovery for the Energy produced during the minimum up time plus their start-up cost. Such generating units cannot set the LMP during Dispatch Intervals in which their Energy is not required but must be produced due to operational constraints.

31.4.3.4.2. Uninstructed Energy Settlement

Uninstructed Energy, i.e., Imbalance Energy produced or consumed in a given Dispatch Interval due to real-time deviations without Dispatch Instructions, shall be paid if positive, or charged if negative, the LMP at the relevant Location, during that Dispatch Interval, as determined in accordance with Section 31.4.3.2.4 and may be subject to Uninstructed Deviation Penalties as set forth in Section 11.2.4.1.2.

31.4.3.4.3 Unaccounted For Energy

UFE is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical load profile errors, and distribution loss deviations. It is the difference between the net energy delivered into a Utility Distribution Company Service Area, adjusted for UDC Service Area Transmission Losses, and the total Metered Demand within the UDC Service Area, adjusted for distribution losses using distribution system loss factors approved by the local regulatory authority.

UFE shall be allocated and settled as set forth in SABP Appendix D but shall not be subject to Uninstructed Deviation Penalties.

31.4.3.4.4. Side Payments and Uplift

Scheduling Coordinators for Resources that are (a) pre-dispatched at Minimum Load, but required to run due to the resource's operational constraints, (b) Dispatched in accordance with Section 31.4.3.2.5, (c) pre-Dispatched for an entire hour in accordance with Section 31.4.2, (d) constrained by their ramp rate while responding to a Dispatch Instruction in the opposite direction of a previous Dispatch Instruction, or (e) constrained by their minimum up time after starting up and responding to a Dispatch Instruction shall be paid an additional payment to ensure the Scheduling Coordinator is paid their bid price for positive Instructed Imbalance Energy from that resource or charged their bid price for negative Instructed Imbalance Energy from that resource.

Side payments for Case (a) above are included in the Unrecovered Commitment Cost compensation in accordance with Sections 31.2.3.4.4.1.1.1 (Day-Ahead Unit Commitment), 5.12.7 (Day-Ahead Residual Unit Commitment), 31.3 (Hour-Ahead Unit Commitment), and 31.3.6. (Hour-Ahead Residual Unit Commitment). Side payments for Case (b) above shall be included automatically in the Imbalance Energy Settlement by paying or charging Imbalance Energy due to Exceptional Dispatch as bid except for resources with no bid, in which case the provisions of Section 11.2.4.2 apply. Side payments for Cases (c) and (d) shall be calculated and paid separately.

The cost of the side payments shall be recovered by uplift. The uplift for Case (a) shall be in accordance with Section 5.12.8. The uplift for Case (b) shall be through the Neutrality Charge in accordance with Section 11.2.9. The uplift cost for Cases (c) and (d) due to positive Instructed Imbalance Energy shall be charged to SCs in proportion to their net system negative Uninstructed Imbalance Energy. The uplift cost for Cases (c) and (d) due to negative Instructed Imbalance Energy shall be charged to SCs in proportion to their net system positive Uninstructed Imbalance Energy.

31.4.4. Replacing or Procuring Additional Operating Reserve

The ISO may a) restore Operating Reserves by Dispatching Imbalance Energy or b) procure additional Operating Reserve in real time by designating unloaded capacity considered to be a Supplemental Energy bid from resources certified to provide Operating Reserves that can be Dispatched within 10 minutes. The ISO shall designate such capacity in order of decreasing Energy Bid price. The Scheduling Coordinator shall be paid for such capacity, in each Dispatch Interval, the dollar amount the resource would have earned above its Energy Bid price if the Energy from that reserved capacity had been Dispatched.

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33. EXPIRATION OF COMMISSION MITIGATION MEASURES

The limitations on prices specified in Sections 2.5.22, 2.5.23, and 2.5.27, and the must-offer obligation specified in Section 5.11, shall expire on September 30, 2002.

32, PROVISIONS FOR THE INTERIM PERIOD UNTIL THE FULL NETWORK MODEL IS IMPLEMENTED

32.1 Terms

For the purposes of this Section 32, the following terms shall apply:

Active Zone	Either the Northern (NP15), Southern (SP15) or Central (ZP26) Zones.
Full Marginal Loss Rate	A rate calculated by the ISO for each Generation and Scheduling Point location to determine the effect on total system Transmission Losses of injecting an increment of Generation at each such location to serve an equivalent incremental MW of Demand distributed proportionately throughout the ISO Control Area.
GMM (Generation Meter Multiplier)	A number which when multiplied by a Generating Unit's Metered Quantity will give the total Demand to be served from that Generating Unit.
Grid Operations Charge	An ISO charge that recovers redispatch costs incurred due to Intra-Zonal Congestion in each Zone. These charges will be paid to the ISO by the Scheduling Coordinators, in proportion to their metered Demand within, and metered exports from, the Zone to a neighboring Control Area.
Inactive Zone	The Humboldt and San Francisco Zones.
Interim Period	The period of time that begins when the ISO inaugurates its simultaneous Day-Ahead Energy Market and Ancillary Services procurement and ends when the ISO begins operations under a Full Network Model. The ISO shall provide at least seven (7) days notice for both events.
Inter-Zonal Congestion	Congestion across an Inter-Zonal Interface.
Inter-Zonal Interface	The (i) group of transmission paths between two adjacent Zones of the ISO Controlled Grid, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will

	be established prior to the use of the interface for Congestion Management; (ii) the group of transmission paths between an ISO Zone and an adjacent Scheduling Point, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; or (iii) the group of transmission paths between two adjacent Scheduling Points, where the group of paths has an established transfer capability and established transmission rights.
Intra-Zonal Congestion	Congestion within a Zone.
Loss Scale Factor	The ratio of expected Transmission Losses to the total Transmission Losses which would be collected if Full Marginal Loss Rates were utilized.
Marginal Loss Factor	The marginal impact of a given Generating Unit's output on total system Transmission Losses.
Scaled Marginal Loss Rate	A factor calculated by the ISO for a given Generator location for each hour by multiplying the Full Marginal Loss Rate for such Generator location by the Loss Scale Factor for the relevant hour.
Zone	A portion of the ISO Controlled Grid within which Congestion is expected to be small in magnitude or to occur infrequently. "Zonal" shall be construed accordingly.

32.2 Effective Dates

Notwithstanding any other provisions of the ISO Tariff, during the Interim Period, the provisions of this Section 32 shall apply.

32.3 Location and Locational Marginal Price

Location shall mean Zone. Locational Marginal Price shall mean the Zonal Market Clearing Price.

SCUC shall calculate Locational Marginal Prices (LMPs) for Energy and Ancillary Services Marginal Prices (ASMPs). The LMPs for Energy shall be calculated for each zone, and shall be used for Energy Settlements. The ASMPs shall be calculated for each Ancillary Service Region and shall be used for Ancillary Services Settlements. The definitions for each (LMPs, ASMPs) remain the same, within the three-zone environment.

32.4 Zonal Congestion Management

32.4.1 The ISO Will Perform Congestion Management.

32.4.1.1 Transmission Congestion. Congestion occurs when there is insufficient transfer capacity to simultaneously implement all of the Schedules that Scheduling Coordinators submit to the ISO.

32.4.1.2 Zone-Based Approach. The ISO will use a Zone-based approach to manage Congestion.

32.4.1.3 Types of Congestion. Congestion that occurs on Inter-Zonal Interfaces is referred to as "Inter-Zonal Congestion." Congestion that occurs due to transmission system constraints within a Zone is referred to as "Intra-Zonal Congestion."

32.4.1.4 Elimination of Potential Transmission Congestion.

The ISO's Day-Ahead and Hour-Ahead scheduling procedures will eliminate potential Congestion by scheduling the use of Inter-Zonal Interfaces by the Scheduling Coordinators based on the Energy Bids that are submitted by Scheduling Coordinators.

32.4.2 Congestion Management. The ISO's Congestion Management in the Day-Ahead Market and Hour-Ahead Market shall:

(1) adjust the Schedules submitted by Scheduling Coordinators as necessary to alleviate Congestion on the basis of any price information submitted through their Energy Bids; and

(2) produce feasible Schedules that eliminate Inter-Zonal Congestion and account for resources' operational Constraints.

32.4.2.1 Elimination of Real Time Inter-Zonal Congestion. In its management of Inter-Zonal Congestion in real time, the ISO will increment or decrement resources, at least cost, based on SCED, in accordance with Dispatch Protocol Section 8.3.

32.4.2.2 Intra-Zonal Congestion and Overgeneration. Except as provided in Section 5.2 of the ISO Tariff, the ISO shall adjust Generating Units, Dispatchable Loads, and Interconnection schedules of System Resources in the adjacent Control Areas to alleviate the constraints via Exceptional Dispatch for Intra-Zonal Congestion Management. The ISO shall decrement Generation or increment Dispatchable Load to manage Overgeneration conditions.

32.5 Active and Inactive Zones.

32.5.1 An Active Zone is one for which a workably-competitive Generation market exists on both sides of the relevant Inter-Zonal Interface for a substantial portion of the year so that Congestion Management can be effectively used to manage Congestion on the relevant Inter-Zonal Interface. Pending the ISO's determination of the criteria for defining "workably competitive generation markets", the Inactive Zones will, as an interim measure, be those specified in Section 32.5.4.

32.5.2 The Congestion Management described in this Section 32 shall not apply to Inter-Zonal Interfaces with Inactive Zones.

32.5.3 For Inactive Zones, any costs associated with Congestion Management on the inactive Inter-Zonal Interface shall be allocated to the Service Area of the Participating TOs who own the inactive Inter-Zonal Interface. Any Intra-Zonal Congestion Management costs within the Inactive Zone and the adjacent Zone will be combined and will be allocated as if the two Zones were a single Zone.

32.5.4 The initial inactive Inter-Zonal Interfaces are the interface between the San Francisco Zone and the remainder of the ISO Controlled Grid, and the interface between the Humboldt Zone and the remainder of the ISO Controlled Grid. The initial Inactive Zones are the San Francisco Zone and the Humboldt Zone.

32.6 Grid Operations Charge for Intra-Zonal Congestion.

Scheduling Coordinators whose resources are re-Dispatched by the ISO, in accordance with Intra-Zonal Congestion Management, will be paid or charged a) based on the Energy bids that they have provided to the ISO, or b) as set forth in Section 11.2.4.2, as applicable. The net re-Dispatch cost will be recovered for each Settlement Period through the Grid Operations Charge, which shall be paid to the ISO by all Scheduling Coordinators in proportion to their metered Demands within the Zone with Intra-Zonal Congestion, and scheduled exports from the Zone with Intra-Zonal Congestion to a neighboring Control Area, provided that, with respect to Demands within an MSS in the Zone and scheduled exports from the MSS to a neighboring Control Area, a Scheduling Coordinator shall be required to pay Grid Operations Charges only with respect to Intra-Zonal Congestion, if any, that occurs on an interconnection between the MSS and the ISO Controlled Grid, and with respect to Intra-Zonal Congestion that occurs within the MSS, to the extent the Congestion is not relieved by the MSS Operator.

32.7 SCUC

SCUC will commit and schedule resources and procure Ancillary Services at least cost for the entire time horizon. SCUC will enforce only Inter-Zonal Constraints. SCUC will enforce resource operational constraints.

32.8 SCED

SCED will Dispatch resources at least cost to procure Imbalance Energy and eliminate any Price Overlap in each Dispatch Interval. SCED will enforce only Inter-Zonal Constraints. SCED will enforce resource operational constraints.

32.9 State Estimator

The State Estimator will not be available during the Interim Period.

32.10 GRID OPERATIONS CHARGE COMPUTATION

32.10.1 Purpose of charge

The Grid Operations Charge is a charge paid by or charged to Scheduling Coordinators that recovers re-Dispatch costs incurred due to Intra-Zonal Congestion management pursuant to Section 32.6 of the ISO Tariff.

32.10.2 Fundamental formulae

32.10.2.1 Payments to SCs with incremented schedules

When it becomes necessary for the ISO to increase the output of a Scheduling Coordinator's Generating Unit i, Dispatchable Load i or System Resource i or reduce a Dispatchable Load i in order to relieve Congestion within a Zone, the ISO will pay the Scheduling Coordinator. The amount that ISO pays the Scheduling Coordinator j is the price specified in the Scheduling Coordinator's Energy Bids for the Generating Unit i or System Resource i or Dispatchable Load i multiplied by the quantity of Energy rescheduled. The formula for calculating the payment to Scheduling Coordinator j for each block b of Energy of its Energy Bid curve in Dispatch Interval t is:

$$INC_{bijt} = adjinc_{bijt} * \Delta inc_{bijt}$$

32.10.2.1.1 Total Payment for Dispatch Interval

The formula for calculating payment to Scheduling Coordinator j whose Generating Unit i or System Resource i has been increased or Dispatchable Load i reduced for all the relevant blocks b of Energy in the Energy Bid curve of that Generating Unit or System Resource or Dispatchable Load in the same Dispatch Interval t is:

$$PayTI_{ijt} = \sum_{b} INC_{bijt}$$

32.10.2.2 Charges to Scheduling Coordinators with decremented schedules

When it becomes necessary for the ISO to decrease the output of a Scheduling Coordinator's Generating Unit i or System Resource i in order to relieve Congestion within a Zone, the ISO will assess a charge to the Scheduling Coordinator. The amount that the ISO will charge Scheduling Coordinator j is the price specified in the Scheduling Coordinator's Energy Bid for the Generating Unit i or System Resource i multiplied by the quantity of Energy rescheduled. The formula for calculating the charge to Scheduling Coordinator j for each block b of Energy in its Energy Bid curve in Dispatch Interval t is:

$$DEC_{bijt} = adjdec_{bijt} * \Delta dec_{bijt}$$

32.10.2.2.1 Total Charge for Dispatch Interval

The formula for calculating the charge to Scheduling Coordinator j whose Generating Unit i or System Resource i has been decreased for all the relevant blocks b of Energy in the Energy Bid curve of that Generating Unit or System Resource in the same Dispatch Interval t is:

$$ChargeTI_{ijt} = \sum_{b} DEC_{bijt}$$

32.10.2.3 Net ISO redispatch costs

The Dispatch Interval net re-Dispatch cost encountered by ISO to relieve Intra-Zonal Congestion is the sum of the amounts paid by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased or Dispatchable Load was decreased during the Dispatch Interval less the sum of the amounts received by the ISO from those Scheduling Coordinators whose Generating Units or System Resource were decreased during the Dispatch Interval. The fundamental formula for calculating the net re-Dispatch cost is:

$$REDISP_{CONGt} = \sum_{j} PayTI_{ijt} - \sum_{j} ChargeTI_{ijt}$$

Note that $REDISP_{CONGt}$ can be either positive or negative. This means that it is possible for the ISO to generate either a net cost or a net income, for any given Dispatch Interval. In the event the ISO does not make use of equal amounts of incremental and decremental dispatched MWHs, then the net re-Dispatch cost becomes the sum of the amounts paid (or charged) by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased (or decreased) or Dispatchable Load was decreased (or increased) during the Dispatch Interval less the sum of the amounts received by the ISO from Scheduling Coordinators through the Imbalance Energy Market.

32.10.2.4 Grid Operations Price

The grid operations price is the Dispatch Interval rate used by the ISO to apportion net Dispatch Interval re-Dispatch costs to Scheduling Coordinators within the Zone with Intra-Zonal Congestion. The grid operations price is calculated using the following formula:

$$GOP_t = \frac{REDISP_{CONG_t}}{\sum_j QCharge_{jt} + \sum_j Export_{jt}}$$

32.10.2.5 Grid Operations Charge

The Grid Operations Charge is the vehicle by which the ISO recovers the net re-Dispatch costs. It is allocated to each Scheduling Coordinator in proportion to the Scheduling Coordinator's Demand in the Zone with Intra-Zonal Congestion and Exports from the Zone with Intra-Zonal Congestion. The formula for calculating the Grid Operations Charge for Scheduling Coordinator j in Dispatch Interval t is:

$$GOC_{jt} = GOP_t * \left(QCharge_{jt} + EXPORT_{jt}\right)$$

32.10.3 Meaning of terms of formulae

32.10.3.1 INC_{bijt} - $

The payment from the ISO due to Scheduling Coordinator j whose Generating Unit i or System Resource i is increased or Dispatchable Load i is reduced within a block b of Energy in its Energy Bid curve in Dispatch Interval t in order to relieve Intra-Zonal Congestion.

32.10.3.2 $adjinc_{bijt}$ - $/MWh

The incremental cost for the rescheduled Generating Unit i or System Resource i or Dispatchable Load$_i$ taken from the relevant block b of Energy in the Energy Bid curve submitted by the Scheduling Coordinator j for the Dispatch Interval t.

32.10.3.3 Δinc_{bijt} - MW

The amount by which the Generating Unit i or System Resource i or Dispatchable Load$_i$ of Scheduling Coordinator j for Dispatch Interval t is increased by the ISO within the relevant block b of Energy in its Energy Bid curve.

32.10.3.4 $PayTI_{ijt}$ - $

The Dispatch Interval payment to Scheduling Coordinator j whose Generating Unit i has been increased or System Resource i or Dispatchable $Load_i$ reduced in Dispatch Interval t of the Trading Day.

32.10.3.5 DEC_{bijt} - $

The charge to Scheduling Coordinator j whose Generating Unit i, System Resource i is decreased or Dispatchable Load i is increased for Dispatch Interval t within a block b of Energy in its Energy Bid curve .

32.10.3.6 $adjdec_{bijt}$ - $/MWh

The decremental cost for the rescheduled Generating Unit i or System Resource i taken from the relevant block b of Energy of the Energy Bid curve submitted by Scheduling Coordinator j for the Dispatch Interval t.

32.10.3.7 Δdec_{bijt} - MW

The amount by which the Generating Unit i, or System Resource i is decreased, or Dispatchable Load i is increased, of Scheduling Coordinator j for Dispatch Interval t by ISO within the relevant block b of Energy of its Energy Bid curve.

32.10.3.8 $ChargeTI_{ijt}$ - $

The Dispatch Interval charge to Scheduling Coordinator j whose Generating Unit i, System Resource i has been decreased or Dispatchable Load i has been increased in Dispatch Interval t of the Trading Day.

32.10.3.9 P_{xt} - $/MWh

The zonal Hourly Ex Post Price, for Uninstructed Imbalance Energy, for Dispatch Interval t in Zone x.

32.10.3.10 $REDISP_{CONGt}$ - $

The Dispatch Interval net cost to ISO to redispatch in order to relieve Intra-Zonal Congestion during Dispatch Interval t.

32.10.3.11 GOP_t - $/MWh

The Dispatch Interval grid operations price for Dispatch Interval t used by the ISO to recover the costs of redispatch for Intra-Zonal Congestion Management.

32.10.3.12 GOC_{jt} - $

The Dispatch Interval Grid Operations Charge by the ISO for Dispatch Interval t for Scheduling Coordinator j in the relevant Zone with Intra-Zonal Congestion.

32.10.3.13 $QCHARGE_{jt}$ – MWh

The Dispatch Interval metered Demand within a Zone for Dispatch Interval t for Scheduling Coordinator j whose Grid Operations Charge is being calculated.

32.10.3.14 $EXPORT_{jt}$ – MWh

The total Energy for Dispatch Interval t exported from the Zone to a neighboring Control Area by Scheduling Coordinator j.

32.11 IMBALANCE ENERGY CHARGE COMPUTATION

32.11.1 Uninstructed Imbalance Energy

Uninstructed Imbalance Energy is Energy produced or consumed due to deviations from the DOP. Uninstructed Imbalance Energy shall be calculated in each Dispatch Interval as the difference between Metered Energy and the integral of the DOP over that Dispatch Interval as follows:

$$UIE_{i,h,k} = GMM_{i,h,k} * ME_{i,h,k} - \int_{t=(k-1)T}^{kT} DOP_{i,h}(t)\,dt = GMM_{i,h,k} * ME_{i,h,k} - \left(SE_{i,h,k} + IIE_{i,h,k}\right) \quad \textbf{(1)}$$

where:

$UIE_{i,h,k}$ **is the Uninstructed Imbalance Energy from resource i during Dispatch Interval k of hour h; and**

$ME_{i,h,k}$ **is the Metered Energy from resource i during Dispatch Interval k of hour h.**

$GMM_{i,h,k}$ **is the Generation Meter Multiplier for Generation resource i during Dispatch Interval k of hour h; if the resource is an import, this represents the Tie Meter Multiplier; if the resource is a load or export, this value is unity. These GMMs are calculated as set forth in Section 32.12.2.1.**

Positive Uninstructed Imbalance Energy shall be paid the relevant Dispatch Interval Locational Marginal Price and negative Uninstructed Imbalance Energy shall be charged the relevant Dispatch Interval Locational Marginal Price. In algebraic terms, adopting the injection convention, the Uninstructed Imbalance Energy charge is given by:

$$UIEC_{i,h,k} = -UIE_{i,h,k}\ LMP_{i,h,k} \quad \textbf{(2)}$$

where:

$UIEC_{i,h,k}$ is the Uninstructed Imbalance Energy charge for resource i during Dispatch Interval k of hour h.

Uninstructed Deviation Penalties may apply in addition to the Uninstructed Imbalance Energy charge as set forth in Section 11.2.4.1.2.

32.12 Transmission Losses.

Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, no allowance shall be made for Transmission Losses (i.e. the Generation Meter Multiplier shall be set at 1.0 for all Scheduling Coordinators) for the Day-Ahead and Hour-Ahead Markets.

32.12.1 Calculation of Transmission Losses for Imbalance Energy Settlements.

The total Demand that may be served by a Generating Unit, in a given hour, taking account of Transmission Losses, is equal to the product of the total Metered Quantity of that Generating Unit in that hour and the Generation Meter Multiplier calculated by the ISO in the hour for that Generator location except in accordance with Section 32.12.3. The Generation Meter Multiplier shall be greater than one (1) where the Generating Unit's contribution to the ISO Controlled Grid reduces Transmission Losses and shall be less than one (1) where the Generating Unit's contribution to the system increases Transmission Losses. All Generating Units supplying Energy to the ISO Controlled Grid at the same electrical bus shall be assigned the same Generation Meter Multiplier.

32.12.2.1 Calculating and Publishing Generation Meter Multipliers.

32.12.2.1.1 By 6:00 p.m. two days preceding a Trading Day, the ISO will calculate, and post on OASIS, an estimated Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. The Generation Meter Multipliers shall be determined utilizing the Power Flow Model based upon the ISO's forecasts of total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO shall continuously update the data to be used in calculating the Generation Meter Multipliers to reflect changes in system conditions on the ISO Controlled Grid, and the ISO shall provide all Scheduling Coordinators with access to such data. The ISO shall not be required to determine new Generation Meter Multipliers for each hour; the ISO will determine the appropriate period for which each set of Generation Meter Multipliers will apply, which period may vary based upon the expected frequency and magnitude of changes in system conditions on the ISO Controlled Grid.

32.12.2.1.2 The ISO shall publish the GMMs that will be used for Imbalance Energy Settlement (i.e. that reflect the Final Hour-Ahead Schedules for that Settlement Period) no later than one hour following the deadline for submitting bids to the ISO Hour-Ahead Market for that Settlement Period.

32.12.2.2 Methodology for Calculating Generation Meter Multiplier. The ISO shall calculate the Generation Meter Multiplier for each Generating Unit location in a given hour by subtracting the Scaled Marginal Loss Rate from 1.0.

32.12.2.2.1 The Scaled Marginal Loss Rate for a given Generating Unit location in a given hour shall equal the product of (i) the Full Marginal Loss Rate for each Generating Unit location and hour, and (ii) the Loss Scale Factor for such hour.

32.12.2.2.2 The ISO shall calculate the Full Marginal Loss Rate for each Generating Unit location for an hour by utilizing the Power Flow Model to calculate the effect on total Transmission Losses for the ISO Controlled Grid of injecting an increment of Generation at each such Generating Unit location to serve an equivalent incremental MW of Demand distributed on a pro-rata basis throughout the ISO Controlled Grid.

32.12.2.2.3 The ISO shall determine the Loss Scale Factor for an hour by determining the ratio of forecast Transmission Losses to the total Transmission Losses which would be collected if Full Marginal Loss Rates were applied to each Generating Unit in that hour.

32.12.3 In the event that the Power Flow Model fails to determine GMMs, for example if GMMs are outside the range of reasonability (typically 0.8 to 1.1), the ISO will use Default GMMs in their place.

~~**Active Zone**~~	~~The Zones so identified in Appendix I to the ISO Tariff.~~
~~**Adjustment Bid**~~	~~A bid in the form of a curve defined by (i) the minimum MW output to which a Scheduling Coordinator will permit a resource (Generating Unit or Dispatchable Load) included in its Schedule or, in the case of an Inter-SC Trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (ii) the maximum MW output to which a Scheduling Coordinator will permit the resource included in its Schedule or, in the case of an Inter-SC Trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (iii) up to a specified number of MW values in between; (iv) a preferred MW operating point; and (v) for the ranges between each of the MW values greater than the preferred operating point, corresponding prices (in $/MWh) for which the Scheduling Coordinator is willing to increase the output of the resource and sell Energy from that resource to the ISO (or, in the case of a Dispatchable Load, decrease the Demand); and (vi) for the ranges between each of the MW values less than the preferred operating point, corresponding prices (in $/MWh) for whichthe Scheduling Coordinator is willing to decrease the output of the resource and purchase Energy from the ISO at the resource's location (or, in the case of a Dispatchable Load, increase the Demand). This data for an Adjustment Bid must result in a monotonically increasing curve.~~
Ancillary Services	Regulation, Spinning Reserve, Non-Spinning Reserve, ~~Replacement Reserve,~~ Voltage Support and Black Start together with such other interconnected operation services as the ISO may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice.
Ancillary Service Marginal Price	**The marginal cost of providing the respective Ancillary Service in the relevant Ancillary Service Region.**
Ancillary Service Region	**A group of adjoining Load Zones for which Ancillary Service requirements are jointly determined.**
Available ~~Transfer~~ Transmission Capacity	For a given transmission path, the capacity rating in MW of the path established consistent with the ISO and WSCC transmission capacity rating guidelines, less any reserved uses applicable to the path.

Balanced Schedule	A Schedule shall be deemed balanced when Generation~~, adjusted for transmission losses~~ equals forecast Demand with respect to all entities for which a Scheduling Coordinator schedules.
~~**BEEP Interval**~~	~~The time period, which may range between five (5) and thirty (30) minutes, over which the ISO's BEEP Software measures deviations in Generation and Demand, and selects Ancillary Service and Supplemental Energy resources to provide balancing Energy in response to such deviations. As of the ISO Operations Date, the BEEP Interval shall be ten (10) minutes. Following a decision, by the ISO Governing Board, the ISO may, by seven (7) days' notice published on the ISO's Home Page, at http://www.caiso.com (or such other internet address as the ISO may publish from time to time), increase or decrease the BEEP Interval within the range of five (5) to thirty (30) minutes.~~
~~**BEEP Interval Ex Post Prices**~~	~~The prices charged to or paid by Scheduling Coordinators for Imbalance Energy in each Zone in each BEEP Interval.~~
~~**BEEP Software**~~	~~The balancing energy and ex post pricing software which is used by the ISO to determine which Ancillary Service and Supplemental Energy resources to Dispatch and to calculate the Ex Post Prices.~~
Bid Cap	**A limit on a bid price, either a Bid Ceiling or a Bid Floor.**
Bid Ceiling	**The maximum price permitted for a bid.**
Bid Floor	**The minimum price permitted for a bid.**
Capacity Resource	**A resource that is required to offer available capacity to the ISO Markets either because (1) it is required to do so as set forth in Section 31.2.3.2.2 of this Tariff or (2) it is required to do so in accordance with a contractual obligation it has with a Load Serving Entity.**
Congestion	A condition that occurs when there is insufficient Available **Transmission**~~Transfer~~ Capacity to implement all Preferred schedules simultaneously or, in real time, to serve all Generation and Demand. "Congested" shall be construed accordingly.
Congestion Revenue	**The difference between charges to Demand and payments to Supply in the Day-Ahead and Hour-Ahead Energy Settlements, including explicit Congestion charges for intertie transmission capacity reservation for Day-Ahead Ancillary**

	<u>Service imports. Congestion Revenue also includes the marginal cost of transmission losses.</u>
<u>Curtailable Demand</u>	**<u>Dispatchable Load that can only be reduced.</u>** ~~Demand from a Participating Load that can be curtailed at the direction of the ISO in the real time dispatch of the ISO Controlled Grid. Scheduling Coordinators with Curtailable Demand may offer it to the ISO to meet Non-spinning or Replacement Reserve requirements.~~
<u>Customer Aggregation</u>	**<u>A customized aggregation of end-use Loads served by a Load Serving Entity (LSE), which the LSE designates for scheduling and Settlement as an alternative to the Standard Aggregation.</u>**
~~**Default GMM**~~	~~Pre calculated GMM based on historical Load and interchange levels.~~
<u>Demand Bid</u>	A bid ~~into the PX~~ indicating a quantity of Energy that an Eligible Customer wishes to purchase and, if relevant, the maximum price that the customer is prepared to pay for that Energy. This bid will only be accepted ~~in the PX auction process~~ if the **<u>Locational Marginal Price</u>** ~~Market Clearing Price~~ is at or below the price of the Demand Bid. A Buyer may state, for each hour, a different price preference for each demand quantity in each location, i.e., the maximum price in each hour at which it is prepared to take a specified amount of Energy in the Day-Ahead Schedule. If a bid is submitted without a price, it is assumed that the bidder is prepared to pay the **<u>Locational Marginal Price</u>**~~Market-Clearing Price~~.
<u>Dispatch Interval</u>	**<u>The time period, which may range between five (5) and thirty (30) minutes, over which the ISO's SCED software measures deviations in Generation and Demand, and selects Ancillary Service and Supplemental Energy resources to provide Imbalance Energy in response to such deviations. Following a decision, by the ISO Governing Board, the ISO may, by seven (7) days' notice published on the ISO's Home Page, at http://www.caiso.com (or such other internet address as the ISO may publish from time to time), increase or decrease the DispatchP Interval within the range of five (5) to thirty (30) minutes.</u>**

Dispatchable Load	**Load that can be curtailed or increased at the direction of the ISO in the real time dispatch of the ISO Controlled Grid, in a measurable and verifiable manner within specified time limits, and that meet standards adopted by the ISO and published on the ISO Home Page.** ~~Load which is the subject of an Adjustment Bid.~~
~~**Effective Price**~~	~~The price, applied to undelivered Instructed Imbalance Energy, calculated by dividing the absolute value of the total payment or charge for Instructed Imbalance Energy by the absolute value of the total Instructed Imbalance Energy, for the Settlement Period; provided that, if both the total payment or charge and quantity of Instructed Imbalance Energy for the Settlement Period are negative, the Effective Price shall be multiplied by -1.0 (minus one).~~
Energy Bid	The price at or above which a **resource**~~Generator~~ has agreed to produce **or the price at or below which a resource has agreed to consume** the next increment of Energy.
~~**Ex Post GMM**~~	~~GMM that is calculated utilizing the real time Power Flow Model in accordance with Section 7.4.2.1.2.~~
~~**Ex Post Price**~~	~~The Hourly Ex Post Price or the BEEP Interval Ex Post Prices.~~
~~**Ex Post Transmission Loss**~~	~~Transmission Loss that is calculated based on Ex Post GMM.~~
Exceptional Dispatch	**Dispatch other than the Dispatch determined by SCED.**
Final Schedule	A Schedule developed by the ISO following receipt of a **Preferred**~~Revised~~ Schedule from a Scheduling Coordinator.
~~**Full Marginal Loss Rate**~~	~~A rate calculated by the ISO for each Generation and Scheduling Point location to determine the effect on total system Transmission Losses of injecting an increment of Generation at each such location to serve an equivalent incremental MW of Demand distributed proportionately throughout the ISO Control Area.~~
Full Network Model	**A network model that includes all network nodes and transmission facilities in the ISO Controlled Grid and a reduced external equivalent network for external systems.**

Generation Dispatch Constraints

Details of any mandatory Generating Unit commitment requirements (e.g., Must-Run Generation) or dispatch limits (minimum output or maximum output) that must be observed due to system operating constraints (e.g., thermal, voltage, or stability limits). These limits are in addition to limits that may be specified by Generators in their Energy or Ancillary Service bids to the ISO~~ or PX~~.

~~GMM (Generation Meter Multiplier)~~

~~A number which when multiplied by a Generating Unit's Metered Quantity will give the total Demand to be served from that Generating Unit.~~

~~**Grid Operations Charge**~~

~~An ISO charge that recovers redispatch costs incurred due to Intra-Zonal Congestion in each Zone. These charges will be paid to the ISO by the Scheduling Coordinators, in proportion to their metered Demand within, and metered exports from, the Zone to a neighboring Control Area.~~

Hour Ahead Market

The forward market for Energy and Ancillary Services to be supplied during a particular Settlement Period that is conducted by the ISO~~, the PX and other Scheduling Coordinators~~ which opens after the ISO's acceptance of the Final Day-Ahead Schedule for the Trading Day in which the Settlement Period falls and closes with the ISO's **publication** ~~acceptance~~ of ~~the~~ Final Hour-Ahead Schedule**s**.

Hourly Ex Post Price

The Energy-weighted average of the **Dispatch**~~BEEP~~ Interval **Location Marginal Prices**~~Ex Post Prices~~ **for a given Location** ~~in each Zone~~ during each **S**~~s~~ettlement **P**~~p~~eriod. ~~The Hourly Ex Post Price will vary between Zones if Congestion is present.~~ This price is used **for certain Exceptional Dispatches,** in the Regulation Energy Payment Adjustment and in RMR settlements.

Hourly Pre-Dispatch

The process in which the ISO Dispatches Energy Bids before the start of the next Settlement Period for that Settlement Period.

Imbalance Energy

Imbalance Energy is Energy from Regulation, Spinning and Non-**S**~~s~~pinning Reserves~~, or Replacement Reserve,~~ or Energy from other Generating Units, System Units, System Resources, or **Dispatchable** Loads that are able to respond to the ISO's request for more or less Energy.

~~**Inactive Zone**~~	~~All Zones which the ISO Governing Board has determined do not have a workably competitive Generation market and as set out in Appendix I to the ISO Tariff.~~
Instructed Imbalance Energy	The real time change in Generation output or Demand (from dispatchable Generating Units, System Units, System Resources or **Dispatchable** Loads) which is instructed by the ISO to ensure that reliability of the ISO Control Area is maintained in accordance with Applicable Reliability Criteria. Sources of Imbalance Energy include Spinning and Non-Spinning Reserves~~, Replacement Reserve~~, and Energy from other dispatchable Generating Units, System Units, System Resources or **Dispatchable** Loads that are able to respond to the ISO's request for more or less Energy.
~~**Inter-Zonal**~~ **Congestion**	~~Congestion across an Inter-Zonal Interface.~~
~~**Inter-Zonal Interface**~~	~~The (i) group of transmission paths between two adjacent Zones of the ISO Controlled Grid, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; (ii) the group of transmission paths between an ISO Zone and an adjacent Scheduling Point, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; or (iii) the group of transmission paths between two adjacent Scheduling Points, where the group of paths has an established transfer capability and established transmission rights.~~
~~**Intra-Zonal Congestion**~~	~~Congestion within a Zone.~~
ISO Adjusted Demand Forecast	**The Demand forecast set forth in 5.12.6.1.1.1.**
Load Aggregation Point	**A set of network nodes that satisfy ISO-specified criteria and may be used for scheduling and settlement of Load.**
Load Distribution Factor (LDF)	**A number that states the relative amount of Load at each node within a Load Aggregation Point. The sum of all LDFs for a single Load Aggregation Point equals one (1.0).**
Load Serving Entity (LSE)	**Any Market Participant (or the duly designated agent of such an entity, including, e.g., a Scheduling Coordinator), including a load aggregator or power marketer, (i) serving End Users within the ISO Control Area and (ii) that has been granted the authority or has an**

	obligation pursuant to California State or local law, regulation or franchise to sell electric energy to End Users located within the ISO Control Area.
Load Zone	**A standard set of network nodes located within the ISO Control Area that has been designated by the ISO to simplify Load scheduling and Settlement.**
Location	**A network node, Load Aggregation Point or Trading Hub.**
Locational Marginal Price	**The marginal price of Energy at a particular Location in a given market.**
~~**Loss Scale Factor**~~	~~The ratio of expected Transmission Losses to the total Transmission Losses which would be collected if Full Marginal Loss Rates were utilized.~~
~~**Marginal Loss Factor**~~	~~The marginal impact of a given Generating Unit's output on total system Transmission Losses.~~
~~**Marginal Proxy Clearing Price**~~	~~The Market Clearing Price determined in accordance with Section 2.5.23.3.1.1.~~
Meter Distribution Factors	**Load Distribution Factors that apply to Settlement Quality Meter Data of a Load aggregation for Imbalance Energy Settlement.**
~~**Must-Offer Generator**~~	~~All entities defined in Section 5.11.1 of the ISO Tariff~~
Net Negative Uninstructed Deviation	The real time change in Generation or Demand associated with underscheduled Load (i.e., Load that appears unscheduled in real time) and overscheduled Generation (i.e., Generation that is scheduled in forward markets and does not appear in real time). Deviations are netted for each **Dispatch**~~BEEP~~ Interval, apply to a Scheduling Coordinator's entire portfolio, and include Load, Generation, Imports and Exports.
~~**Non-Emergency Clearing Price**~~	~~The Market Clearing Price determined in accordance with Section 2.5.23.3.1.2.~~
~~**Non-Emergency Clearing Price Limit**~~	~~The limitation on Market Clearing Prices determined in accordance with Section 2.5.23.3.1.2.~~
~~**Non-PX Generation**~~	~~Generation that is scheduled by a Scheduling Coordinator, other than the PX, and that supplies Loads through the use of transmission or distribution facilities owned by Participating TOs.~~
~~**Non-PX Load**~~	~~Load that is scheduled by a Scheduling Coordinator, other than the PX, and which is supplied through the~~

	~~use of transmission or distribution facilities owned by Participating TOs.~~
Participating Load	An entity ~~providing Curtailable Demand, which~~**that** has undertaken in writing to comply with all applicable provisions of the ISO Tariff **in regards to Load**, as they may be amended from time to time.
~~**PMS (Power Management System)**~~	~~The ISO computer control system used to monitor the real time performance of the various elements of the ISO Controlled Grid, control Generation, and perform operational power flow studies.~~
Power Flow Model	The **network model used by the ISO's network applications (e.g. SCUC, SCED)** ~~computer software used by the ISO~~ to model the voltages, power injections and power flows on the ISO Controlled Grid **and external systems.**~~and determine the expected Transmission Losses and Generation Meter Multipliers.~~
Power Transfer Distribution Factor	**The proportion of Energy that flows on any given network branch for an Energy transfer between two specific network nodes.**
Preferred Schedule	The initial Schedule produced by a Scheduling Coordinator that represents its preferred mix of Generation to meet its Demand. For each Generator, the Schedule will include the quantity of output~~, details of any Adjustment Bids,~~ and the location of the Generator. For each Load, the Schedule will include the quantity of consumption~~, details of any Adjustment Bids,~~ and the location of the Load. The Schedule will also specify quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators. The Preferred Schedule **may**~~will~~ be balanced with respect to Generation, ~~Transmission Losses,~~ Load and trades between Scheduling Coordinators.
~~**Price Mitigation Reserve Deficiency**~~	~~Any clock hour in which the ISO's maximum actual reserve margin is below seven (7) percent.~~
Price Overlap	The price range of bids for Supplemental Energy or Energy associated with Ancillary Services bids for any **Dispatch**~~BEEP~~ Interval that includes decremental and incremental Energy Bids where the price of the decremental Energy Bids exceeds the price of the incremental Energy Bids.

Price Taker	**A Supply or Demand Schedule without an associated Energy bid.**
~~**Proxy Price**~~	~~The value determined for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator in accordance with Section 2.5.23.3.4.~~
~~**PX (Power Exchange)**~~	~~The California Power Exchange Corporation, a state chartered, nonprofit corporation charged with providing a Day-Ahead forward market for Energy in accordance with the PX Tariff. The PX is a Scheduling Coordinator and is independent of both the ISO and all other Market Participants.~~
~~**PX Auction Activity Rules**~~	~~The rules by which bids submitted to and validated by the PX may be modified or withdrawn during a PX Energy market auction.~~
~~**PX Participant**~~	~~An entity that is authorized to buy or sell Energy or Ancillary Services through the PX, and any agent authorized to act on behalf of such entity.~~
~~**PX Protocols**~~	~~The rules, protocols, procedures and standards attached to the PX Tariff as Appendix E, promulgated by the PX (as amended from time to time) to be complied with by the PX and Market Participants in relation to operation and participation in the PX Markets.~~
~~**PX Tariff**~~	~~The California Power Exchange Operating Agreement and Tariff, dated March 31, 1997, as it may be modified from time to time.~~
~~**Replacement Reserve**~~	~~Generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and ramping to a specified Load point within a sixty (60) minute period, the output of which can be continuously maintained for a two hour period. Also, Curtailable Demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours.~~
~~**Revised Schedule**~~	~~A Schedule submitted by a Scheduling Coordinator to the ISO following receipt of the ISO's Suggested Adjusted Schedule.~~
~~**Scaled Marginal Loss Rate**~~	~~A factor calculated by the ISO for a given Generator location for each hour by multiplying the Full Marginal Loss Rate for such Generator location by the Loss Scale Factor for the relevant hour.~~

Schedule	A statement of (i) Demand, including quantity, duration and Take-Out Points**; or** (ii) Generation, including quantity, duration, **and** location of Generating Unit **or Scheduling Point**~~, and Transmission Losses~~; **or**~~and~~ (iii) Ancillary Services which will be self provided, (if any) submitted by a Scheduling Coordinator to the ISO **or procured by the ISO**. "Schedule" includes Preferred Schedules **and**~~, Suggested Adjusted Schedules,~~ Final Schedules**.**~~, and Revised Schedules.~~
Scheduling Distribution Factors	**Load Distribution Factors that apply to a Load aggregation for scheduling and Settlement of Day-Ahead and Hour-Ahead Energy.**
Security Constrained Economic Dispatch (SCED)	**The program used by the ISO to Dispatch Energy in real-time as described in Section 31.4.3.2.2.1.**
Security Constrained Unit Commitment (SCUC)	**The program used by the ISO to commit resources and schedule Energy and Ancillary Services in the Day-Ahead and Hour-Ahead Markets and to perform the Residual Unit Commitment Process. The SCUC incorporates both a unit commitment process and an economic dispatch process.**
Standard Aggregation	**The default aggregation of end-use Loads within the Load Zone.**
~~**Start-Up Fuel Cost Charge**~~	~~The charge determined in accordance with Section 2.5.23.3.7.~~
~~**Start-Up Fuel Cost Demand**~~	~~The level of Demand specified in Section 2.5.23.3.7.3.~~
~~**Start-Up Fuel Cost Invoice**~~	~~The invoice submitted to the ISO in accordance with Section 2.5.23.3.7.6.~~
~~**Start-Up Fuel Cost Trust Account**~~	~~The trust account established in accordance with Section 2.5.23.3.7.2.~~
~~**Start-Up Fuel Costs**~~	~~The cost of the fuel consumed by a particular generating unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchronized to the grid, whichever is later, until the time the generating unit is synchronized or re-synchronized to the grid and producing Energy. Start-Up Fuel Costs are determined by multiplying the actual amount of fuel consumed by the proxy gas price as determined in accordance with Section 2.5.23.3.4 at the time the fuel is consumed.~~

State Estimator — **An application that estimates the voltages, power flows, transmission losses and other characteristics of the power system at any given time based on measurements.**

~~**Suggested Adjusted Schedule**~~ — ~~The output of the ISO's initial Congestion Management for each Scheduling Coordinator for the Day-Ahead Market ("Suggested Adjusted Day-Ahead Schedule") or for the Hour-Ahead Market ("Suggested Adjusted Hour-Ahead Schedule"). These Schedules will reflect ISO suggested adjustments to each Scheduling Coordinator's Preferred Schedule to resolve Inter-Zonal Congestion on the ISO Controlled Grid, based on the Adjustment Bids submitted. These schedules will be balanced with respect to Generation, Transmission Losses, Load, and trades between Scheduling Coordinators to resolve Inter-Zonal Congestion.~~

Supplemental Energy — Energy from Generating Units bound by a Participating Generator Agreement, Loads bound by a Participating Load Agreement, System Units, and System Resources which have uncommitted capacity following finalization of the Hour-Ahead Schedules~~ and for which Scheduling Coordinators have submitted bids to the ISO at least half an hour before the commencement of the Settlement Period~~.

Supply — **Generation or import.** ~~The rate at which Energy is delivered to the ISO Controlled Grid measured in units of watts or standard multiples thereof, e.g., 1,000W=1 KW; 1,000 KW = 1MW, etc.~~

Trading Hub — **A standard aggregation of network nodes defined by the ISO. A Trading Hub may be used as the Source or Sink of an FTR.**

Unaccounted for Energy (UFE) — UFE is the difference in Energy, for each UDC Service Area and Settlement Period, between the net Energy delivered into the UDC Service Area, adjusted for UDC Service Area Transmission Losses ~~(calculated in accordance with Section 7.4.2)~~, and the total metered Demand within the UDC Service Area adjusted for distribution losses using Distribution System loss factors approved by the Local Regulatory Authority. This difference is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical Load profile errors, and distribution loss deviations.

Universal Node Identifier (UNI) — **A unique identification code assigned by each UDC to each End-Use Customer location within that UDC's Distribution System as set forth by the CPUC.**

~~**Usage Charge**~~	~~The amount of money, per 1 kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific congested Inter-Zonal Interface during a given hour.~~
Warning Notice	A Notice issued by the ISO when the operating requirements for the ISO Controlled Grid are not met in the Hour-Ahead Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve~~, Replacement Reserve~~ and Supplemental Energy available to the ISO does not satisfy the Applicable Reliability Criteria.
WEnet (Western Energy Network)	An electronic network that facilitates communications and data exchange between the ISO **and**~~,~~ Market Participants~~ and the public~~ in relation to the status and operation of the ISO Controlled Grid.
~~**Winter Clearing Price Limit**~~	~~The limitation on Market Clearing Prices determined in accordance with Section 2.5.23.3.1.3.~~
~~**Zone**~~	~~A portion of the ISO Controlled Grid within which Congestion is expected to be small in magnitude or to occur infrequently. "Zonal" shall be construed accordingly.~~

Inserted Table

APPENDIX C. SCHEDULING TIMELINE

The following table shows the timeline of market events for the ISO, LSEs, and SCs.

Time	ISO	LSE	SC	FTR Owner	PTO	Event
Two Days Ahead						
1800 (6pm)	✓					Publish updated Available Transmission Capacity, Ancillary Services requirements, and 2-day-ahead load forecast.
One Day Ahead						
0600 (6am)	✓					Publish Advisory information (load forecast, Ancillary Services regions and requirements, ATC, LDFs, PTDFs)
0600 (6am)	✓					Update system load forecast and ancillary service requirements
0600 (6am)		✓				Submit Direct Access Customer load forecast
0630 (6:30am)	✓					Publish forecasted Direct Access load by UDC
By 0800 (8am) (By 2 hours before the deadline for submitting Preferred DA Schedules)	✓					Notify Scheduling Coordinators of unit-specific Reliability Must Run requirement
0800 (8am)				✓		FTR holder notify ISO via Secondary Registration System of ownership quantities and Scheduling Coordinator scheduling responsibility.
0830 (8:30 am)					✓	Participating Transmission Owner will notify ISO amounts transmission capacity to reserve for its transmission service customers under Existing Contracts.
By 0800 (8am) (By 2 hours before the deadline for submitting Preferred DA Schedules)			✓			Scheduling Coordinators representing Reliability Must Run resources notify ISO of Payment Option selection associated with unit-specific Reliability Must Run notification.
0900 (9am)	✓					Publish Firm Transmission Rights and Existing Contract rights available for scheduling for the Day-Ahead market.

Time	ISO	LSE	SC	FTR Owner	PTO	Event
1000 (10am)			✓			Submit DA Energy, start-up and minimum load energy and Ancillary Services Schedules and bids. Bids submitted at this time shall be used for both the DA Market as well as the DA Residual Unit Commitment process.
1000 (10am)	✓					Validate all SC Energy schedules including RMR requirements and bids, notify and resolve incorrect schedules and bids if any. Validate all SC Ancillary Service schedules and bids notify and resolve incorrect Ancillary Service schedules and bids if any.
1000 (10am)	✓					Close DA market; simultaneous DA Energy market, DA Unit Commitment, DA Congestion Management, and DA Ancillary Services procurement, subject to Automatic Market Power Mitigation.
1300 (1pm)	✓					Publish final DA Energy and Ancillary Services Schedules, Unit Commitments to meet scheduled load and DA Public Market Information
1330 (1:30pm)	✓					Perform DA Residual Unit Commitment using start-up and minimum load costs data and submitted energy bids from resources, subject to Automatic Market Power Mitigation
Hour-Ahead and Real-Time Market						
Prior to 2300 (11pm) (1 hours prior to OH and every hour thereafter during the TD)			✓			Submit (a set of 24 consecutive hours) HA Energy and Ancillary Service Schedules and bids.
Starting 2300 (11pm) (1 hours prior to OH and every hour thereafter during the TD)			✓			Submit (individual hourly) HA Energy and Ancillary Service Schedules and bids, HA Residual Unit Commitment bids.

Time	ISO	LSE	SC	FTR Owner	PTO	Event
Starting 2300 (11:00pm) (1 hours prior to OH and every hour thereafter during TD)	✓					Close HA market; simultaneous HA Energy market, HA Unit Commitment, HA Congestion Management, and HA Ancillary Services procurement, HA Residual Unit Commitment. Close RT market. Any unused but available energy bid after the HA market has run will be considered in the RT market. Submission of bids into the Hour-Ahead market will be the last opportunity for bids to be submitted to the RT Market.
Starting 2215 (10:15pm) (1hour and 45 minutes prior to the start of OH and every hour thereafter during TD)	✓					Publish final HA Energy and Ancillary Services Schedules and Additional Unit Commitments and DA Public Market Information. Begin RT pre-dispatch process
2330 (30 minutes prior to OH and every hour thereafter during TD)	✓					Complete pre-dispatch subject to Automatic Market Power Mitigation; communicate pre-dispatch instructions through ADS
Every 10 minutes during OH	✓					Perform Real-Time Economic Dispatch; communicate dispatch instruction through ADS; publish 10-minute Ex Post LMPs
End of OH	✓					Publish RT Public Market Information

Legend

M Month of TD

TD Trade Day

DA Day-Ahead

HA Hour-Ahead

OH Operating Hour

RT Real-Time

~~Day-ahead Schedule Timeline~~

	~~Responsible Parties~~							
~~Line~~	~~Time (Before or on)~~	~~ISO~~	~~Non-PX SCs~~	~~PX~~	~~Must-Take and Reliability generation~~	~~UDC~~	~~PX Participants~~	~~Actions~~
	~~Two days ahead~~							
~~0~~	~~6:00 PM~~	~~x~~						~~Publish forecasted transmission conditions (Generator Meter Multipliers, system load forecast (by Zones), estimated Ancillary Service requirements, scheduled transmission outages, loop flows, congestion, ATC, etc.)~~
	~~One day ahead~~							
~~1~~	~~5:00 AM~~	~~X~~						~~Notify Scheduling Coordinators of unit-specific Reliability Must Run requirements~~
~~2~~	~~6:00 AM~~	~~x~~						~~Update system load forecast and Ancillary Service requirements.~~
~~3~~			~~X~~					~~Notify ISO of price option for Reliability Must Run Units for which notification was provided at 5:00 a.m.~~
~~4~~			~~x~~					~~Provide direct access load forecasts to the ISO.~~
~~5~~	~~6:30 AM~~	~~x~~						~~Provide net direct access load forecasts to UDCs.~~
~~6~~	~~9:30 AM~~						~~x~~	~~Submit individual unit schedules, AS schedules/price bids and incs/decs for CM to the PX.~~
~~7~~	~~9:45 AM~~			~~x~~				~~Validate individual unite schedules, AS schedule/price bids and incs/decs.~~
~~8~~	~~10:00 AM~~			~~x~~				~~Finalize MCP and Initial preferred schedules. Communicate MCP and resulting schedules to the PX participants.~~
								~~Finalize AS schedules (self-provision) or AS price bids. Communicate resulting AS schedules and/or price to PX participants.~~

~~9~~				~~x~~				
~~10~~			~~x~~	~~x~~				~~Submit initial preferred energy schedules to the ISO.~~
~~11~~			~~x~~	~~x~~				~~Submit Ancillary Service bids and/or self-provided Ancillary Service schedules to the ISO.~~
~~12~~	~~10:00 AM~~	~~x~~						~~Validate all SC energy schedules, including RMR requirements, and bids; notify and resolve incorrect schedules and bids, if any.~~

~~13~~		~~x~~						~~Validate all SC Ancillary Service schedules and bids; notify and resolve incorrect Ancillary Service schedules and bids, If any.~~
~~14~~		~~x~~						~~Start the inter-zonal congestion management evaluation process and Ancillary Services bid evaluation.~~
~~15~~	~~11:00 AM~~	~~x~~						~~If no inter-zonal congestion exists, go to line 27.~~
~~16~~		~~x~~						~~Complete advisory dispatch schedules and transmission prices if inter-zonal congestion exists.~~
~~17~~		~~x~~						~~Complete the advisory schedules and prices of each Ancillary Service.~~
~~18~~		~~x~~						~~Notify all SC if inter-zonal congestion exists. Publish advisory transmission prices.~~
~~19~~		~~x~~						~~Inform all SCs their advisory dispatch schedules if inter-zonal congestion exists.~~
~~20~~		~~x~~						~~Inform all SCs advisory AS schedules and prices if inter-zonal congestion exists.~~
~~21~~	~~11:05 PM~~		~~x~~	~~x~~			~~x~~	~~Start the process of developing revised schedules and price bids (the PX may iterate with PX participants).~~
~~22~~			~~x~~	~~x~~			~~x~~	~~Start the process of developing revised AS schedules and price bids (the PX may iterate with PX participants).~~
~~23~~	~~12:00 PM~~		~~x~~	~~x~~				~~Submit revised preferred schedules and price bids to the ISO.~~
~~24~~			~~x~~	~~x~~				~~Submit revised preferred AS schedules and price bids to the ISO.~~
~~25~~	~~12:00 PM~~	~~x~~						~~Validate all SC schedules and bids; notify and resolve incorrect schedules and bids, if any.~~
								~~Validate all SC AS schedules and bids; notify and resolve incorrect~~

~~26~~		~~x~~						~~schedules and bids, if any.~~
~~27~~		~~x~~						~~Start the inter-zonal congestion management evaluation process and Ancillary Services bid evaluation.~~

~~28~~	~~1:00 PM~~	~~x~~						~~Complete final dispatch schedules and transmission prices.~~
~~29~~		~~x~~						~~Complete final schedules and prices of each Ancillary Service.~~
~~30~~	~~1:00 PM~~	~~x~~						~~Complete final schedules.~~
~~31~~	~~1:00 PM~~	~~x~~						~~Inform all SCs their final dispatch schedules.~~
~~32~~		~~x~~						~~Inform all SCs their final AS schedules and prices.~~
~~33~~		~~x~~						~~Publish transmission prices if inter-zonal congestion exists.~~
~~34~~		~~x~~						~~Calculate and communicate with SC the specific SCs zonal prices if asked.~~
~~35~~				~~x~~				~~Publish PX prices.~~
~~36~~				~~x~~				~~Communicate the final generation and load schedules to PX participants.~~
~~37~~				~~x~~				~~Communicate the final Ancillary Service schedules to PX participants.~~
~~38~~		~~x~~						~~Develop net schedules for each of the Control Area interfaces. These interfaces include SC net schedules, Control Area net schedules and/or individual transactions.~~
~~39~~		~~x~~						~~Call each adjacent Control Area and check that net schedules at each interface point match. Search for discrepancies and identify transactions that do not match. Resolve discrepancies with the involved SCs or eliminate the transactions with discrepancies.~~

Appendix F

Rate Schedules

Schedule 1

Grid Management Charge

Part A – Monthly Calculation of Grid Management Charge (GMC)

The Grid Management Charge consists of three separate service charges: the Control Area Services Charge, the Congestion Management Charge, and the Ancillary Services and Real-Time Energy OperationsCharge.

1. The rate for the Control Area Services Charge will be calculated by dividing the GMC costs allocated to this service charge by the total Control Area Gross Load and exports, in MWh.

2. The rate for the Congestion Management Charge will be calculated by dividing the GMC costs allocated to this service charge by the total Scheduling Coordinators' inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh.

3. The rate for the Ancillary Services and Real-Time Energy Operations Charge will be calculated by dividing the GMC costs allocated to this service charge by the total purchases and sales (including out-of-market transactions) of Ancillary Services **plus the capacity selected by the ISO in the Residual Unit Commitment Process for which an SC receives a capacity payment**, ~~Supplemental Energy~~ **Real-Time Energy**, and Imbalance Energy (both instructed and uninstructed) in MWh plus 50% of effective self-provision of Ancillary Services in MWh.

Ancillary Services:

Regulation, Spinning Reserve, Non-Spinning Reserve, ~~Replacement Reserve,~~ Voltage Support and Black Start together with such other interconnected operation services as the IS0 may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources
to Loads while maintaining reliable operation of the IS0 Controlled Grid in accordance with Good Utility Practice.

ISO TARIFF APPENDIX H

Methodology for Developing the Weighted Average Rate for Wheeling Service

Methodology for Developing the Weighted Average Rate for Wheeling Service

The weighted average rate payable for Wheeling over joint facilities at each Scheduling Point shall be calculated as follows, applying the formula separately to the applicable Wheeling Access Charges:

$$\text{WBAC} = \sum\left(P_n \times \frac{Q_n}{\sum Q_n}\right)$$

Where:

WBAC = Weighted-average Wheeling Access Charge for each ISO Scheduling Point

P_n = The applicable Wheeling Access Charge rate for a TAC Area or Participating TO_n in \$/kWh as set forth in Section 7.14 and Section 5 of the TO Tariff.

Q_n = The Available **Transmission**~~Transfer~~ Capacity (in MW), whether from transmission ownership or contractual entitlements, of each Participating TO_n for each ISO Scheduling Point which has been placed within the ISO Controlled Grid. Available **Transmission**~~Transfer~~ Capacity shall not include capacity associated with Existing Rights of a Participating TO as defined in Section 2.4.4 of the ISO Tariff.

n = the number of Participating TOs from 1 to n

ISO TARIFF APPENDIX I

ISO Congestion Management Zones

~~ISO Congestion Management Zones~~

~~1. **Active Zones**~~
~~A. Northern Zone (NP15)~~
~~B. Central Zone (ZP26)~~
~~C. Southern Zone (SP15)~~

~~2. **Inactive Zones**~~
~~A. Humboldt Zone~~
~~B. San Francisco Zone~~

~~Note: The ISO's Initial Congestion Management Zones were described in the Joint Application of the IOUs for Authorization to Convey Operational Control of Designated Jurisdictional Facilities to an ISO filed April 29, 1996, Docket No. EC96-19-000.~~

APPENDIX K. ~~[NOT USED]~~ LOCATIONAL MARGINAL PRICING

K.1 Overview

K.1.1 Simultaneous Energy and Ancillary Services Optimization

The Locational Marginal Prices (LMPs) are based on the marginal costs produced by solving an Alternating Current (AC) Optimal Power Flow (OPF) problem. In forward Energy and Ancillary Service markets, i.e., the Day-Ahead (Day-Ahead) market and the Hour-Ahead (Hour-Ahead) market, the AC OPF program, is referred to as the Security Constrained Unit Commitment (SCUC) process. The SCUC determines which resources should be committed and the optimal power output for each of the committed resources and the hourly LMPs.

K.1.2 Day-Ahead Energy and Ancillary Service Markets

During the Day-Ahead Market, upon receiving the Preferred Day-Ahead Energy schedules and Ancillary Service bids, the SCUC process determines optimally which participating resources and Capacity Resources should be committed in addition to the resources that are already committed previously or self-committed as indicated by the Energy schedules in order to meet the scheduled load and the Ancillary Service requirements in Day-Ahead. The SCUC process is expected to produce optimal decisions on the commitment status of resources. Based on the results of the SCUC, the SCED produces the optimal Day-Ahead Energy schedules, the LMPs for Energy settlement, the quantities and prices of Ancillary Service procurement.

K.1.3 Day-Ahead Residual Unit Commitment

After the Day-Ahead Market, the Day-Ahead Residual Unit Commitment Process (Day-Ahead RUC) is carried out to commit additional resources or de-commit resources as necessary to meet the Day-Ahead ISO Demand Forecast. The Day-Ahead RUC process follows the same SCUC process except that the input to the Day-Ahead RUC process is the Day-Ahead commitment status. The SCUC is used to produce advisory Day-Ahead RUC schedules only; LMPs are not used for any settlement purpose.

K.1.4 Hour-Ahead Energy and Ancillary Service Markets

During the Hour-Ahead Market, upon receiving the Preferred Hour-Ahead Energy schedules and Ancillary Service bids, the SCUC process determines optimally which resources should be committed in addition to the resources that are already committed previously or self-committed as indicated by the Preferred Hour-Ahead Energy schedules in order to meet the scheduled load and the Ancillary Service requirements in Hour-Ahead. The SCUC process is expected to produce optimal decisions on the commitment status of resources. Based on the results of the SCUC, the SCED produces the optimal Hour-Ahead Energy schedules, the LMPs for Energy settlement, the quantities and prices of Ancillary Service procurement. The Hour-Ahead Market is an incremental market; only the incremental amounts of Energy and capacity above those of the Day-Ahead Market are settled at the respective Hour-Ahead Locational Marginal Prices.

K.1.5 Hour-Ahead Residual Unit Commitment

After the Hour-Ahead Market and before the beginning of the hour, the Hour-Ahead Residual Unit Commitment (Hour-Ahead RUC) is carried out to commit additional resources or de-commit resources as necessary to meet the Hour-Ahead ISO Demand Forecast. The Hour-Ahead RUC Process follows the same SCUC process except that the input to the Hour-Ahead RUC process is the Hour-Ahead commitment status. The SCED is used to produce advisory Hour-Ahead RUC schedules only; LMPs are not used for Settlement.

K.1.6 Real-Time Energy Markets

At the beginning of each Dispatch Interval, the resources are dispatched in real-time by the SCED. The SCED uses the commitment status produced by Hour-Ahead RUC, the Supplemental Energy bids and the Ancillary Service Energy bids, and the updated network configuration provided by the state estimator. The Real-Time Market is an incremental market; only the amounts of Energy different than those of the Final Hour-Ahead Schedules are settled at the respective real-time LMPs. The SCED program is used to optimally Dispatch the power output of each committed resource and determine the real-time LMPs during each Dispatch Interval.

K.2 Locational Marginal Pricing of Energy and Ancillary Services

K.2.1 Definition of Nodes

Each resource is defined as a unique node. Multiple resources connected to the same bus bar electrically are considered difference nodes that are linked by zero impedance branches.

K.2.2 AC Power Flow Equations

The AC power flow equations are a set of equations that determine uniquely the nodal injections of active and reactive power and the voltage magnitudes and phase angles. Given a power system with N nodes, the nodes are numbered as follows for convenience without loss of generality:

- PQ nodes (i.e., load or generator operating at reactive power limit) are numbered from 1 to N_d.
- PV nodes (i.e., generator or load with voltage control) are numbered from N_d+1 to N_d+N_g.
- Slack node (i.e., the reference node) is numbered as the last bus, N.

The set of AC power flow equations generally consists of:

- N_d equations that describe the active power balance at the PQ nodes.
- N_g equations that describe the active power balance at the PV nodes,

- N_d equations that describe the reactive power balance at the PQ nodes.

Mathematically, the equations are described as follows:

$$P_i(\mathbf{x}) - P_i = 0 \qquad \text{for i = 1, 2, …, N-1} \qquad (1)$$

$$Q_i(\mathbf{x}) - Q_i = 0 \qquad \text{for i = 1, 2, …, } N_d \qquad (2)$$

where $\mathbf{x} = [\boldsymbol{\theta}^T\ \mathbf{V}^T]^T$ where $\boldsymbol{\theta} = [\theta_1, \theta_2, ..., \theta_{N-1}]^T$ and $\mathbf{V}=[V_1, V_2, …, V_{Nd}]^T$, representing voltage phase angles and magnitudes, respectively. Eq.(1) represents active power balancing equations at all nodes except the reference node and P_i denotes active power injection at node *i*. Eq.(2) represents reactive power balancing equations at the PQ nodes and Q_i denotes reactive injection at node *i*.

K.2.3 Loss Equations

The active power loss of the system is determined by Eq.(3) and the reactive power loss of the system is determined by Eq.(4).

$$\sum_{i=1}^{N} P_i(\mathbf{x}) - P_{loss} = 0 \qquad (3)$$

$$\sum_{i=1}^{N} Q_i(\mathbf{x}) - Q_{loss} = 0 \qquad (4)$$

where P_{loss} denotes the active power loss of the system; and Q_{loss} denotes the reactive power loss of the system.

K.2.4 Nodal Power Injection Constraints

The active power injection constraints at all nodes are described as follows:

$$P_i - P_i^{Max} \le 0 \qquad \text{for i = 1, 2, …, N} \qquad (5)$$

$$P_i^{Min} - P_i \le 0 \qquad \text{for i = 1, 2, …, N} \qquad (6)$$

where P_i^{Max} is the upper limit of active power injection at node i; and P_i^{Min} is the lower limit of the active power injection at node i.

The reactive power constraints at PV nodes are described as follows:

$$Q_i(\mathbf{x}) - Q_i^{Max} \le 0 \qquad \text{for i = } N_d+1, N_d+2, …, N_d+N_g \qquad (7)$$

$$Q_i^{Min} - Q_i(\mathbf{x}) \le 0 \qquad \text{for i = } N_d+1, N_d+2, …, N_d+N_g \qquad (8)$$

where Q_i^{Max} is the upper limit of reactive power injection at node i; and Q_i^{Min} is the lower limit of the reactive power injection at node i.

Note P_i are independent control variables and $Q_i(\mathbf{x})$ at PV nodes are functions of voltage variables. Reactive power injections at PQ nodes are constants.

K.2.5 Voltage Constraints

The voltage magnitude constraints on PQ nodes are described as follows:

$$V_i - V_i^{Max} \leq 0 \qquad \text{for i = 1, 2, …, } N_d \tag{9}$$

$$V_i^{Min} - V_i \leq 0 \qquad \text{for i = 1, 2, …, } N_d \tag{10}$$

where V_i^{Max} is the upper limit of voltage magnitude at node i; and V_i^{Min} is the lower limit of the voltage magnitude at node i.

The voltage phase angle constraints on all nodes except the reference node are described as follows:

$$\theta_i - \theta_i^{Max} \leq 0 \qquad \text{for i = 1, 2, …, N-1} \tag{11}$$

$$\theta_i^{Min} - \theta_i \leq 0 \qquad \text{for i = 1, 2, …, N-1} \tag{12}$$

where θ_i^{Max} is the upper limit of voltage phase angle at node i; and θ_i^{Min} is the lower limit of the voltage phase angle at node i.

K.2.6 Transmission Constraints

The transmission constraints fall into one of the three categories: (i) directional branch constraint, (ii) directional branch group constraint, and (iii) nomogram constraint. Any transmission constraint can be represented in the following form:

$$F_k(\mathbf{x}) - F_k^{Max} \leq 0 \tag{13}$$

or specifically on interties when Ancillary Services compete for use of the available transmission capacity,

$$F_k(\mathbf{x}) + \sum_{i \in T_k} \left(SP_i + NS_i + RU_i \right) - F_k^{Max} \leq 0 \tag{14}$$

where $F_k(\mathbf{x})$ is the power flow carried by the device that is described by constraints k; and F_k^{Max} is the upper limit of the power flow on constraint k; SP_i , NS_i *and* RU_i are quantities of Spinning Reserve, Non-Spinning Reserve and Regulation Up from resource i provided across intertie k; T_k denotes the set of resources that compete for the use of intertie k; F_k^{Max} is the upper limit of power flow on constraint k.

K.2.7 AC OPF Formulation for Simultaneous Energy and Reserve Auction

The objective is to minimize Energy and Ancillary Services procurement costs based on submitted Energy and Ancillary Services bids. The Lagrange function is as follows:

$$L = \sum_{i=1}^{N-1} C_i(P_i) + C_N\left[P_N(\mathbf{x})\right] +$$ (Energy Bids)

$$\sum_{i \in I_{RU}} C_i^{RU}(RU_i) +$$ (Regulation Up Bids)

$$\sum_{i \in I_{SP}} C_i^{SP}(SP_i) +$$ (Spinning Reserve Bids)

$$\sum_{i \in I_{NS}} C_i^{NS}(NS_i) +$$ (Non-Spinning Reserve Bids)

$$\sum_{i \in I_{RD}} C_i^{RD}(RD_i) +$$ (Regulation Down Bids)

$$\sum_{i=1}^{N-1} \lambda_i\left[P_i(\mathbf{x}) - P_i\right] +$$ (Active Power Balance)

$$\sum_{i=1}^{N_d} \gamma_i\left[Q_i(\mathbf{x}) - Q_i\right] +$$ (Reactive power balance at PQ nodes)

$$\sum_j \lambda_j^{RU}\left(R_j^{RU} - \sum_{i \in I_{RU} \cap Z_j} RU_i\right) +$$ (Regulation Up Requirement)

$$\sum_j \lambda_j^{SP}\left(R_j^{RU} + R_j^{SP} - \sum_{i \in I_{RU} \cap Z_j} RU_i - \sum_{i \in I_{SP} \cap Z_j} SP_i\right) +$$ (Spinning Requirement)

$$\sum_j \lambda_j^{NS}\left(R_j^{RU} + R_j^{SP} + R_j^{NS} - \sum_{i \in I_{RU} \cap Z_j} RU_i - \sum_{i \in I_{SP} \cap Z_j} SP_i - \sum_{i \in I_{NS} \cap Z_j} NS_i\right) +$$ (Non Spinning Requirement)

$$\sum_j \lambda_j^{RD}\left(R_j^{RD} - \sum_{i \in I_{RD} \cap Z_j} RD_i\right) +$$ (Regulation Down Requirement)

$$\sum_{i=1}^{N-1} \pi_i^{Max}(P_i + RU_i + SP_i + NS_i - P_i^{Max}) +$$ (Active Power Maximum Limit)

$$\sum_{i=1}^{N-1} \pi_i^{Min}(P_i^{Min} - P_i + RD_i) +$$ (Active Power Minimum Limit)

$$\sum_{i\in I_{RU}} \alpha_i^{RU}\left(RU_i - RU_i^{Max}\right)+$$ (Regulation Up Bid Amount Limit)

$$\sum_{i\in I_{RU}} \beta_i^{RU}\left(-RU_i\right)+$$ (Positive Regulation Up Bid Limit)

$$\sum_{i\in I_{SP}} \alpha_i^{SP}\left(SP_i - SP_i^{Max}\right)+$$ (Spinning Bid Amount Limit)

$$\sum_{i\in I_{SP}} \beta_i^{SP}\left(-SP_i\right)+$$ (Positive Spinning Bid Amount Limit)

$$\sum_{i\in I_{NS}} \alpha_i^{NS}\left(NS_i - NS_i^{Max}\right)+$$ (Non Spinning Bid Amount Limit)

$$\sum_{i\in I_{NS}} \beta_i^{NS}\left(-NS_i\right)+$$ (Positive Non Spinning Bid Amount Limit)

$$\sum_{i\in I_{RD}} \alpha_i^{RD}\left(RD_i - RD_i^{Max}\right)+$$ (Regulation Down Bid Amount Limit)

$$\sum_{i\in I_{RD}} \beta_i^{RD}\left(-RD_i\right)+$$ (Positive Regulation Down Bid Amount Limit)

$$\sum_{i=1}^{N-1} \alpha_i^{OP}(RU_i + SP_i + NS_i - 10RR_i)+$$ (assuming a ten minute Ramp Limit)

$$\sum_k \mu_k\left[F_k(\mathbf{x}) + \sum_{i\in T_k}\left(SP_i + NS_i + RU_i\right) - F_k^{Max}\right]$$ (Network Constraint)

where the symbols are defined as follows:

$C_i(P_i)$	The Energy bid or cost function of resource (i.e.node) i
$C_N(P_N(\mathbf{x}))$	The Energy bid or cost function of reference node N
$C_i^{RU}(RU_i)$	The Regulation Up bid function of resource i
$C_i^{SP}(SP_i)$	The Spinning Reserve bid function of resource i
$C_i^{NS}(NS_i)$	The Non-Spinning Reserve bid function of resource i
$C_i^{RD}(RD_i)$	The Regulation Down bid function of resource i
RU_i	The quantity of Regulation Up capacity provided by resource i

SP_i	The quantity of Spinning Reserve capacity provided by resource i
NS_i	The quantity of Non-Spinning Reserve capacity provided by resource i
RD_i	The quantity of Regulation Down capacity provided by resource I
λ_i	The LMP of active power or Energy at node i
γ_i	The LMP of reactive power at node i
λ_j^{RU}	The ASMP of Regulation Up in Ancillary Services Region j
R_j^{RU}	The net requirement of Regulation Up in Ancillary Services Region j
I_{RU}	The set of resources providing Regulation Up
Z_j	The set of resources in region j
λ_j^{SP}	The marginal price of Spinning Reserve in Ancillary Services Region j
R_j^{SP}	The net requirement of Spinning Reserve in Ancillary Services Region j
I_{SP}	The set of resources providing Spinning Reserve
λ_j^{NS}	The AMSP of Non-Spinning Reserve in Ancillary Services Region j
R_j^{NS}	The net requirement of Non-Spinning Reserve in Ancillary Services Region j
I_{NS}	The set of resources providing Non-Spinning Reserve
λ_j^{RD}	The ASMP of Regulation Down in Ancillary Services Region j
R_j^{RD}	The net requirement of Regulation Down in Ancillary Services Region j
I_{RD}	The set of resources providing Regulation Down
π_i^{Max}	Marginal cost of upper limit of active power at node i
π_i^{Min}	Marginal cost of lower limit of active power at node i
α_i^{RU}	Marginal cost of upper limit of Regulation Up bid at node i
β_i^{RU}	Marginal cost of lower limit of Regulation Up bid at node i
RU_i^{Max}	Upper limit of Regulation Up bid at node i
α_i^{SP}	Marginal cost of upper limit of Spinning Reserve bid at node i
β_i^{SP}	Marginal cost of lower limit of Spinning Reserve bid at node i
SP_i^{Max}	Upper limit of Spinning Reserve bid at node i
α_i^{NS}	Marginal cost of upper limit of Non-Spinning Reserve bid at node i
β_i^{NS}	Marginal cost of lower limit of Non-Spinning Reserve bid at node i
NS_i^{Max}	Upper limit of Spinning Reserve bid at node i
α_i^{RD}	Marginal cost of upper limit of Regulation Down bid at node i
β_i^{RD}	Marginal cost of lower limit of Regulation Down bid at node i
RD_i^{Max}	Upper limit of Regulation Down bid at node i
α_i^{OP}	Marginal cost of 10 minute ramp limit at node i
μ_k	Marginal (shadow) cost of transmission constraint k

K.2.8 Definition of LMP for Energy

The LMP for settlement of Energy at node *i* is determined to be the marginal cost of supplying an additional MW of active power at node *i* as follows:

$$\frac{\partial L}{\partial\left[P_i(\mathbf{x})-P_i\right]}=\lambda_i \tag{15}$$

Each nodal price can be decomposed into three components: (i) marginal cost at the reference bus, (ii) marginal cost of thermal transmission loss, and (iii) marginal cost of transmission system constraints which include but are not limited to transmission line constraints, reactive power supply constraints, voltage constraints, phase angle (e.g., stability) constraints.

$$\lambda_i=\lambda_N-\lambda_N L_i-\sum_k \mu_k S_{ki} \tag{16}$$

where

$\lambda_N=\dfrac{\partial C_N}{\partial P_N}$ = System marginal cost of Energy at the reference node

L_i = The i-th element of the Loss Contribution Factor, $\mathbf{L}$, defined in Section K.2.9 , that corresponds to active power injection, i.e., $\dfrac{\partial P_{loss}}{\partial P_i}$.

μ_k = Marginal cost of constraint *k*

S_{ki} = The (*k, i*)-th element of Power Transfer Distribution Factors, $\mathbf{S}$, defined in Section K.2.10 , which represents the incremental amount of power flow (MW or MVAR as the case may be) on constraint *k* when a unit of power (MW or MVAR as the case may be) is injected into node *i* and withdrawn at the reference node.

The following mathematical formulas illustrate the theory and procedure for calculating the three components. At the optimal solution, the following Kuhn-Tucker condition must be satisfied:

$$\frac{\partial L}{\partial \mathbf{x}}=\frac{\partial C_N}{\partial P_N}\frac{\partial P_N}{\partial \mathbf{x}}+\sum_{i=1}^{N-1}\lambda_i\frac{\partial P_i}{\partial \mathbf{x}}+\sum_{i=1}^{N_d}\gamma_i\frac{\partial Q_i}{\partial \mathbf{x}}+\sum_k \mu_k\frac{\partial F_k}{\partial \mathbf{x}}=0 \tag{17}$$

Differentiate (18) on both sides to obtain (19).

$$P_N(\mathbf{x})=P_{loss}(\mathbf{x})-\sum_{i=1}^{N-1}P_i(\mathbf{x}) \tag{18}$$

$$\frac{\partial P_N}{\partial \mathbf{x}}=\frac{\partial P_{loss}}{\partial \mathbf{x}}-\sum_{i=1}^{N-1}\frac{\partial P_i}{\partial \mathbf{x}} \tag{19}$$

Substituting (19) into (17) to obtain

$$\sum_{i=1}^{N-1}\left(\lambda_i - \frac{\partial C_N}{\partial P_N}\right)\frac{\partial P_i}{\partial \mathbf{x}} + \sum_{i=1}^{N_d}\gamma_i \frac{\partial Q_i}{\partial \mathbf{x}} = -\frac{\partial C_N}{\partial P_N}\frac{\partial P_{loss}}{\partial \mathbf{x}} - \sum_k \mu_k \frac{\partial F_k}{\partial \mathbf{x}} \tag{20}$$

The above equation can be manipulated and written into vector form as follows:

$$\left[(\lambda_1 - \lambda_N) \quad (\lambda_2 - \lambda_N) \quad \ldots \quad (\lambda_{N-1} - \lambda_N) \quad \gamma_1 \quad \gamma_2 \quad \ldots \quad \gamma_{N_d}\right] = -\lambda_N \mathbf{L} - [\mu_1 \quad \mu_2 \quad \mu_3 \quad \ldots]\cdot \mathbf{S}$$

where γ_i represents the LMP of reactive power at a PQ node *i,* which is not currently used.

K.2.9 Loss Contribution Factor

Loss Contribution Factor relates total system losses to power (active power or reactive power) injection. The Loss Contribution Factors are defined in (21) as follows. The *i*-th element of $\mathbf{L}$ is $\frac{\partial P_{loss}}{\partial P_i}$ or $\frac{\partial P_{loss}}{\partial Q_i}$ as the case may be.

$$\mathbf{L} = \frac{\partial P_{loss}}{\partial \mathbf{x}}\begin{bmatrix} \frac{\partial P_1}{\partial \mathbf{x}} \\ \frac{\partial P_2}{\partial \mathbf{x}} \\ \vdots \\ \frac{\partial P_{N-1}}{\partial \mathbf{x}} \\ \frac{\partial Q_1}{\partial \mathbf{x}} \\ \frac{\partial Q_2}{\partial \mathbf{x}} \\ \vdots \\ \frac{\partial Q_{N_d}}{\partial \mathbf{x}} \end{bmatrix}^{-1} \tag{21}$$

K.2.10 Power Transfer Distribution Factor

Power Transfer Distribution Factors are sensitivities of power flows on transmission constraints (including but not limited to branch thermal constraints, voltage constraints, reactive power constraints and nomogram constraints) with respect to active or reactive power injections. The Power Transfer Distribution Factors are defined as follows in (22). The (k, i)-th element of $\mathbf{S}$ represents the incremental amount of power flow (MW or MVAR as the case may be) on constraint k when a unit of power (MW or MVAR as the case may be) is injected into node i and withdrawn at the reference node.

$$\mathbf{S} = \begin{bmatrix} \dfrac{\partial F_1}{\partial \mathbf{x}} \\ \dfrac{\partial F_2}{\partial \mathbf{x}} \\ \dfrac{\partial F_3}{\partial \mathbf{x}} \\ \vdots \end{bmatrix} \cdot \begin{bmatrix} \dfrac{\partial P_1}{\partial \mathbf{x}} \\ \dfrac{\partial P_2}{\partial \mathbf{x}} \\ \vdots \\ \dfrac{\partial P_{N-1}}{\partial \mathbf{x}} \\ \dfrac{\partial Q_1}{\partial \mathbf{x}} \\ \dfrac{\partial Q_2}{\partial \mathbf{x}} \\ \vdots \\ \dfrac{\partial Q_{N_d}}{\partial \mathbf{x}} \end{bmatrix}^{-1} \tag{22}$$

When DC Power Flow equations are used for modeling the power system, the PTDFs in (22) are simplified as follows:

$$\mathbf{S} = \begin{bmatrix} \dfrac{\partial F_1}{\partial \boldsymbol{\theta}} \\ \dfrac{\partial F_2}{\partial \boldsymbol{\theta}} \\ \dfrac{\partial F_3}{\partial \boldsymbol{\theta}} \\ \vdots \end{bmatrix} \cdot \begin{bmatrix} \dfrac{\partial P_1}{\partial \boldsymbol{\theta}} \\ \dfrac{\partial P_2}{\partial \boldsymbol{\theta}} \\ \vdots \\ \dfrac{\partial P_{N-1}}{\partial \boldsymbol{\theta}} \end{bmatrix}^{-1} \tag{23}$$

where

F_i = the active power flow carried by constraint *i,* which is represented as a function of phase angles $\boldsymbol{\theta}$.

P_i = the active power injection at node *i,* which is represented as a function of phase angles $\boldsymbol{\theta}$ by the DC Power Flow equation:

$$\mathbf{B}\,\boldsymbol{\theta} = \mathbf{P} \tag{24}$$

$\mathbf{B}$ = The bus admittance matrix.

$\boldsymbol{\theta}$ = $[\theta_1, \theta_2, ..., \theta_{N-1}]^{\mathrm{T}}$, the vector of phase angles.

$\mathbf{P}$ = $[P_1, P_2, ..., P_{N-1}]^{\mathrm{T}}$, the vector of active power nodal injections.

K.2.11 LMPs for Load Aggregation Points

The computation described above is at node level. The LMP for a Load Aggregation Point will be a Load-weighted average of the nodal LMPs of the underlying network nodes. The Load weights are the Load

Distribution Factors predetermined by the ISO according to Section 31.**Error! Reference source not found.**..

K.2.12 Definition of ASMP for Regulation Up

The ASMP for Regulation Up in Ancillary Service Region *j* is determined to be the marginal cost of supplying an additional MW of Regulation Up in Ancillary Service Region *j* as follows:

$$\frac{\partial L}{\partial\left(R_j^{RU} - \sum_{i \in I_{RU} \cap Z_j} RU_i\right)} = \lambda_j^{RU} + \lambda_j^{SP} + \lambda_j^{NS} \qquad (25)$$

A supplier of Regulation Up that produces less Energy in the corresponding market (i.e., Day-Ahead or Hour-Ahead) than it would have been economic for it to produce because of its selection to provide Regulation Up is paid its opportunity cost through the ASMP for Regulation Up defined above.

K.2.12.1 Opportunity Cost for Provision of Regulation Up

The foregone profit associated with the provision of Regulation Up is equal to the product of (1) the difference between (a) the Energy that a Generator could have sold at the specific LMP and (b) the Energy sold as a result of reducing the Generator's output to provide Regulation Up at the direction of the ISO; and (2) the LMP existing at the time the Generator was selected to provide the Regulation Up, less the Generator's Energy bid for the Energy that was not scheduled due to the provision of Regulation Up.

K.2.13 Definition of ASMP for Spinning Reserve

The ASMP for Spinning Reserve in Ancillary Service Region *j* is determined to be the marginal cost of supplying an additional MW of Spinning Reserve in Ancillary Service Region *j* as follows:

$$\frac{\partial L}{\partial\left(R_j^{SP} - \sum_{i \in I_{SP} \cap Z_j} SP_i\right)} = \lambda_j^{SP} + \lambda_j^{NS} \qquad (26)$$

A supplier of Spinning Reserve that produces less Energy in the corresponding market (i.e., Day-Ahead or Hour-Ahead) than it would have been economic for it to produce because of its selection to provide Spinning Reserve is paid for its opportunity cost through the ASMP for Spinning Reserve as defined above.

K.2.13.1 Opportunity Cost for Provision of Spinning Reserve

The foregone profit associated with the provision of Spinning Reserve is equal to the product of (1) the difference between (a) the Energy that a Generator could have sold at the specific LMP and (b) the Energy sold as a result of reducing the Generator's output to provide Spinning Reserve at the direction of the ISO; and (2) the LMP existing at the time the Generator was selected to provide the Spinning Reserve, less the Generator's Energy bid for the Energy that was not scheduled due to the provision of Spinning Reserve..

K.2.14 Definition of ASMP for Non-Spinning Reserve

The ASMP for Non-Spinning Reserve in Ancillary Service Region *j* is determined to be the marginal cost of supplying an additional MW of Non-Spinning Reserve in Ancillary Service Region *j* as follows:

$$\frac{\partial L}{\partial\left(R_j^{NS} - \sum_{i \in I_{NS} \cap Z_j} NS_i\right)} = \lambda_j^{NS} \tag{27}$$

A supplier of Non-Spinning Reserve that produces less Energy in the corresponding market (i.e., Day-Ahead or Hour-Ahead) than it would have been economic for it to produce because of its selection to provide Non-Spinning Reserve is paid for its opportunity costs through the ASMP for Non-Spinning Reserve as defined above.

K.2.14.1 Opportunity Costs for Provision of Non-Spinning Reserve

The foregone profit associated with the provision of Non-Spinning Reserve is equal to the product of (1) the difference between (a) the Energy that a Generator could have sold at the specific LMP and (b) the Energy sold as a result of reducing the Generator's output to provide Non-Spinning Reserve at the direction of the ISO; and (2) the LMP existing at the time the Generator was selected to provide the Non-Spinning Reserve, less the Generator's Energy bid for the Energy that was not scheduled due to the provision of Non-Spinning Reserve.

K.2.15 Definition of ASMP for Regulation Down

The ASMP for Regulation Down in Ancillary Service Region *j* is determined to be the marginal cost of supplying an additional MW of Regulation Down in Ancillary Service Region *j* as follows:

$$\frac{\partial L}{\partial\left(R_j^{RD} - \sum_{i \in I_{RD} \cap Z_j} RD_i\right)} = \lambda_j^{RD} \tag{28}$$

A supplier of Regulation Down that produces more Energy in the corresponding market (i.e., Day-Ahead or Hour-Ahead) than it would have been economic for it to produce because of its selection to provide Regulation Down is paid its opportunity costs through the ASMP for Regulation Down as defined above.

K.2.15.1 Opportunity Cost for Provision of Regulation Down

The foregone profit associated with the provision of Regulation Down is equal to the product of (1) the difference between (a) the Energy sold as a result of increasing the Generator's output to provide Regulation Down at the direction of the ISO and; (b) the Energy that a Generator could have sold at the specific LMP; and (2) the Generator's Energy bid at the time the Generator was selected to provide the Regulation Down, less the LMP for the Energy that was scheduled in order to provide Regulation Down.

K.2.16 Definition of Shadow Price for Network Constraints

The shadow price for network constraint *k* is determined to be the marginal cost of relaxing the constraint by one additional unit as follows:

$$\frac{\partial L}{\partial\left[F_k(\mathbf{x})+\sum_{i\in T_k}\left(SP_i+NS_i+RU_i\right)-F_k^{Max}\right]}=\mu_k \tag{29}$$

K.2.17 Price for Point-To-Point Transmission

The price for using the transmission system to deliver one MW from Source *i* to Sink *j* is defined as follows:

$$\lambda_j-\lambda_i=\lambda_N(L_i-L_j)+\sum_k\mu_k(S_{ki}+S_{kj}) \tag{30}$$

The first term on the right hand side of (30) represents the cost of losses attributable to the transaction between node *i* and node *j*; and the second term on the right hand side of (30) represents the cost of network constraints.

K.2.18 Price for Network Service Transmission

To avoid double subscripts in notations, any network service transmission can be described, without loss of generality, as the right for sending ($p_1, p_2, \ldots, p_s$) % of one MW at nodes ($1, 2, \ldots, s$) and receiving ($p_{s+1}, p_{s+2}, \ldots, p_{s+r}$) % of one MW at nodes ($s+1, s+2, \ldots, s+r$). Using this notation, the price for network service transmission is described as follows:

$$\begin{aligned}\sum_{j=s+1}^{s+r}\lambda_j p_j-\sum_{i=1}^{s}\lambda_i p_i&=\sum_{j=s+1}^{s+r}\left(\lambda_N-\lambda_N L_j-\sum_k\mu_k S_{kj}\right)p_j-\sum_{i=1}^{s}\left(\lambda_N-\lambda_N L_i-\sum_k\mu_k S_{ki}\right)p_i\\&=\lambda_N\left(\sum_{i=1}^{s}L_i p_i-\sum_{j=s+1}^{s+r}L_j p_j\right)+\sum_k\mu_k\left(\sum_{i=1}^{s}S_{ki}p_i-\sum_{j=s+1}^{s+r}S_{kj}p_j\right)\end{aligned} \tag{31}$$

The first term on the right hand side of (31) represents cost of losses attributable to the transactions associated with the network service; and the second term on the right hand side of (31) represents cost of network constraints. This price is also the value of the Network Service Right with the same network service transmission.

K.2.19 Total Congestion Revenue from Energy Settlement

The total Congestion Revenue collected by the ISO, except for explicit Ancillary Services Congestion charges is as follows:

$$
\begin{aligned}
CR &= -\sum_{i=1}^{N} \lambda_i P_i = -\sum_{i=1}^{N-1} \lambda_i P_i - \lambda_N P_N = -\sum_{i=1}^{N-1} \left(\lambda_N - \lambda_N L_i - \sum_k \mu_k S_{ki} \right) P_i - \lambda_N P_N \\
&= \sum_k \mu_k \sum_{i=1}^{N-1} (S_{ki} P_i) - \lambda_N \left[P_N + \sum_{i=1}^{N-1} (1 - L_i) P_i \right] = \sum_k \mu_k F_k^{Max} + \lambda_N \left[\sum_{i=1}^{N-1} L_i P_i - P_{loss} \right]
\end{aligned}
\qquad (32)
$$

The first term on the right hand side of (32) represents revenue associated with network constraints. The second term on the right hand side of (32) represents the difference between actual losses and the marginal cost of losses.

ANCILLARY SERVICES REQUIREMENTS PROTOCOL

ANCILLARY SERVICES REQUIREMENTS PROTOCOL

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ANCILLARY SERVICES REQUIREMENTS PROTOCOL (ASRP)

ASRP 1 OBJECTIVES, DEFINITIONS AND SCOPE

ASRP 1.1 Objectives

(a) The ISO needs to have available to it sufficient Ancillary Services of a standard necessary to enable it to maintain the reliability of the ISO Controlled Grid.

(b) This Protocol describes the ISO's basis for determining its Ancillary Services requirements and the required standard for each Ancillary Service.

(c) These requirements and standards apply to all Ancillary Services whether self-provided or procured by the ISO.

(d) This Protocol also describes the means by which the ISO will monitor performance of these Ancillary Services to ensure that the required standards are met and maintained.

ASRP 1.2 Definitions

ASRP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff. References to ASRP are to this Protocol or to the stated paragraph of or Appendix to this Protocol.

ASRP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following expression shall have the meaning set opposite it:

"Area Control Error (ACE)" means the sum of the instantaneous difference between the actual net interchange and the scheduled net interchange between the ISO Control Area and all adjacent Control Areas and the ISO Control Area's frequency correction and time error correction obligations.

"Dynamic Schedule" means a telemetered reading or value which is updated in real time and which is used as a schedule in the ISO EMS calculation of ACE and the integrated value of which is treated as a schedule for interchange accounting purposes.

"ISO Home Page" means the ISO internet home page at www.caiso.com or such other internet address as the ISO shall publish from time to time.

ASRP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

ASRP 1.3 Scope

ASRP 1.3.1 Scope of Application to Parties

This Protocol applies to the ISO and to the following:

(a) Participating Generators

(b) Operators

(c) UDCs

(d) Providers of Curtailable Demand

(e) Scheduling Coordinators

(f) Metered Subsystem Operators.

ASRP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

ASRP 2 ANCILLARY SERVICES STANDARDS

ASRP 2.1 Basis of Standards

ASRP 2.1.1 Basic criteria

(a) The ISO shall base its Ancillary Services standards upon the Western System Coordinating Council (WSCC) Minimum Operating Reliability Criteria (MORC) and North American Electric Reliability Council (NERC) Criteria to the extent they are applicable to the ISO Controlled Grid.

(b) The ISO may adjust the Ancillary Services standards temporarily to take into account, among other things, variations in system conditions, real-time dispatch constraints, contingencies, and voltage and dynamic stability assessments.

ASRP 2.2 Review of Standards

ASRP 2.2.1 Grid Operations Committee Review

The ISO Grid Operations Committee shall periodically undertake a review of the ISO Controlled Grid operations to determine any revision to the Ancillary Services standards to be used in the ISO Control Area. As a minimum the ISO Technical Advisory Committee shall conduct such reviews to accommodate revisions to WSCC and NERC standards.

ASRP 2.2.2 Contents of Grid Operations Committee Reviews

Periodic reviews may include, but are not limited to:

(a) analysis of the deviation between actual and forecast Demand;

(b) analysis of patterns of unplanned Generating Unit Outages;

(c) analysis of compliance with NERC and WSCC Criteria;

(d) analysis of operation during system disturbances;

(e) analysis of patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand; and

(f) analysis of patterns of unplanned transmission Outages.

ASRP 2.3 Communications

A Participating Generator or provider of Curtailable Demand wishing to offer any Ancillary Service must provide a direct ring down voice communications circuit (or a dedicated telephone line available 24 hours a day every day of the year) between the control room operator for the Generating Unit or Curtailable Demand providing the Ancillary Service and the ISO Control Center. Each Participating Generator must also provide an alternate method of voice communications with the ISO from the control room in addition to the direct communication link required above.

ASRP 3 ANCILLARY SERVICE OBLIGATIONS FOR SCHEDULING COORDINATORS

ASRP 3.1 Ancillary Service Obligations

The ISO shall assign to each Scheduling Coordinator a share of the ISO's total Regulation, Spinning Reserve~~,~~ and Non-Spinning Reserve ~~and Replacement Reserve~~ requirements. The ISO will calculate the share for which each Scheduling Coordinator is responsible (its "obligation") in accordance with the standards set forth in the ASRP.

ASRP 3.2 Right to Self Provide

Each Scheduling Coordinator may self provide all, or a portion, of its Regulation and Reserve obligation **within each Ancillary Services Region**~~within each Zone~~ or adjust its obligation through Inter-Scheduling Coordinator Ancillary Service Trades.

ASRP 4 REGULATION STANDARDS

ASRP 4.1 Standard for Regulation: Quantity Needed

ASRP 4.1.1 Basis for Standard

The ISO needs sufficient Generating Units immediately responsive to Automatic Generation Control (AGC) in order to allow the ISO Control Area to meet the WSCC and NERC control performance criteria by continuously balancing Generation to meet deviations between actual and scheduled Demand and to maintain interchange schedules.

ASRP 4.1.2 Determination of Regulation Quantity Needed

The quantity of Regulation capacity needed for each Settlement Period of the Day-Ahead Market and the Hour-Ahead Markets shall be determined as a percentage of the ~~aggregate scheduled~~ISO-forecasted Demand for that Settlement Period.

ASRP 4.1.3 Percentage Determination

The exact percentage required for each Settlement Period of the Day-Ahead Market and the Hour-Ahead Markets shall be determined by the ISO based upon its need to meet the WSCC and NERC control performance criteria.

ASRP 4.1.4 Publication of Estimated Percentage for Day-Ahead Market

In accordance with the requirements of SP 3.2.1, the ISO will publish on ~~WEnet~~ OASIS its estimate of the percentage it will use for determining the quantity of Regulation it requires for each Settlement Period of the Day-Ahead Market for that Trading Day.

ASRP 4.1.5 Publication of Estimated Percentage for Hour-Ahead Market

The ISO will publish on ~~WEnet~~ OASIS its estimate of the percentage it will use to determine the quantity of Regulation it requires for each Hour-Ahead Market.

ASRP 4.1.6 Additional Regulation Requirement

Additional Regulation capacity may be procured by the ISO for the real-time operating period if needed to meet the WSCC and NERC control performance criteria.

ASRP 4.2 Standard for Regulation: Performance

ASRP 4.2.1 Operating Characteristics of Generating Unit

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

(a) it must be capable of being controlled and monitored by the ISO Energy Management System (EMS) by means of the installation and use of a standard ISO direct communication and direct control system, a description of which and criteria for any temporary exemption from which, the ISO shall publish on the ISO internet “Home Page;”

(b) it must be capable of achieving at least the ramp rates (increase and decrease in MW/minute) stated in ~~its bid~~the ISO Master F~~f~~ile (which will be updated based on testing or actual performance) for the full amount of Regulation capacity offered;

(c) the Regulation capacity offered must not exceed the maximum ramp rate (MW/minute) of that Unit times a value within a range from a minimum of ten minutes to a maximum of thirty minutes, which value shall be specified by the ISO and published on the ISO's internet "Home Page;"

(d) the Generating Unit to ISO Control Center telemetry must in a manner meeting ISO standards include indications of whether the Generating Unit is on or off AGC at the Generating Unit terminal equipment; and

(e) the Generating Unit~~e~~ must be capable of the full range of movement within the amount of Regulation capability offered without manual Generating Unit operator intervention of any kind.

ASRP 4.2.2 Operational EMS/SCADA Equipment

Each Participating Generator must ensure that the ISO EMS control and related SCADA equipment for its generating facility are operational throughout the time period during which Regulation is required to be provided.

ASRP 4.3 SC's Obligation for Regulation

Each Scheduling Coordinator's Obligation for Regulation for each Settlement Period of the Day-Ahead Market and for each Hour-Ahead Market ~~in each Zone~~ shall be calculated based upon the ratio of metered Demand (excluding exports) by each Scheduling Coordinator ~~in each identified Zone~~ for that Settlement Period to the total metered Demand (excluding exports) for that Settlement Period. ~~in that Zone.~~

ASRP 4.4 Standard for Regulation: Control

The ACE will be calculated by the ISO EMS. Control signals will be sent from the ISO EMS to raise or lower the output of Generating Units or System Reources providing Regulation when ACE exceeds the allowable ISO Control Area dead band for ACE. Use of dynamic schedules to provide Regulation from System Resources must be certified and approved by the ISO.

ASRP 4.4.1 Dynamic Scheduling of Regulation from External Resources

Scheduling Coordinators are allowed to bid or self-provide their Regulation obligation in whole or in part from resources located outside the ISO Control Area by dynamically scheduling such resources; if it can be demonstrated that the control function will use dedicated communication links (either directly or through EMS computers) for ISO computer control and telemetry to provide this function in accordance with the ISO's standards and procedures posted on the ISO Home Page.

ASRP 4.5 Standard for Regulation: Procurement

ASRP 4.5.1 Procurement of Non Self-Provided Regulation

Regulation necessary to meet ISO requirements not met by self-provided Regulation will be procured by the ISO as described in the ISO Tariff.

ASRP 4.5.2 Certification and Testing Requirements

Each Generating Unit and System Unit used to bid Regulation or used to self provide Regulation must have been certified and tested by the ISO using the process defined in Appendix A to this Protocol.

ASRP 4.5.3 [Not Used]

ASRP 4.5.4 [Not Used]

ASRP 5 OPERATING RESERVE STANDARDS

The ISO needs, as a minimum, Operating Reserve, consisting of Spinning Reserve and Non-Spinning Reserve, sufficient to meet WSCC MORC~~. The Operating Reserve requirement shall be equal to (a) 5% of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from hydroelectric resources, plus 7% of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from other resources, or (b) the single largest Contingency, if this is greater~~ or ~~(c) by reference to such~~ more stringent criteria as the ISO may determine from time to time. ~~This Operating Reserve requirement does not include the Operating Reserve required to cover the Generation or services described in ASRP 5.2(a) and (b).~~

ASRP 5.1 [Not Used] ~~Standard for Spinning Reserve: Quantity Needed~~

ASRP 5.1.1 [Not Used] ~~Minimum Spinning Reserve Quantity~~

~~The Spinning Reserve component of Operating Reserve shall be no less than one-half the Operating Reserve required for each Settlement Period of the Day-Ahead Market, the Hour-Ahead Market and the Real Time Market.~~

ASRP 5.1.2 Providing both Spinning Reserve and Regulation

Spinning Reserve and Regulation may be provided as separate services from the same Generating Unit, provided that the sum of Spinning Reserve and Regulation provided is not greater than the maximum ramp rate of the Generating Unit (MW/minute) times ten.

ASRP 5.2 Standard for Non-Spinning Reserve: Quantity Needed

The required quantity of Non-Spinning Reserve shall be equal to the required quantity of Operating Reserve less the quantity of Spinning Reserve determined in ASRP 5.1 plus;

(a) an amount of Non-Spinning Reserve equal to Interruptible Imports (which must either be self provided by theScheduling Coordinators responsible for the Interruptible Imports from resources within the ISO Controlled Grid or purchased from the ISO); and

(b) an amount of Non-Spinning Reserve equal to on-demand obligations to other entities or Control Areas (which must be self provided by the Scheduling Coordinators responsible for the on-demand obligations from resources within the ISO Controlled Grid).

Scheduling Coordinators may self provide their allocated quantity of Non-Spinning Reserve under ASRP 5.2(a) and (b) from Spinning Reserve not already committed to the ISO, if they wish.

ASRP 5.3 Standard for Spinning Reserve: Performance

ASRP 5.3.1 Spinning Reserve Capability

Each Generating Unit or external import of a System Resource scheduled to provide Spinning Reserve must be capable of converting the full capacity reserved to Energy production within ten minutes after the issue of the Dispatch instruction by the ISO, and of maintaining that output or scheduled interchange for at least two hours.

ASRP 5.3.2 Availability

Each Participating Generator shall ensure:

(a) that its Generating Units scheduled to provide Spinning Reserve are available for Dispatch throughout the Settlement Period for which it has been scheduled; and

(b) that its Generating Units scheduled to provide Spinning Reserve are responsive to frequency deviations throughout the Settlement Period for which they have been scheduled.

ASRP 5.4 Standard for Non-Spinning Reserve Performance

ASRP 5.4.1 Non-Spinning Reserve Resources

Non-Spinning Reserve may be provided by, among others, the following resources:

(a) Demand which can be reduced by Dispatch;

(b) interruptible exports;

(c) on-demand rights from other entities or Control Areas;

(d) off line Generating Units qualified to provide Non-Spinning Reserve; and

(e) external imports of System Resources.

ASRP 5.4.2 Non-Spinning Reserve Capability

Each resource providing Non-Spinning Reserve must be capable of converting the full capacity reserved to Energy production within ten minutes after the issue of the Dispatch instruction by the ISO, and of maintaining that output for at least two hours.

ASRP 5.4.3 Availability

Each provider of Non-Spinning Reserve must ensure that its resources scheduled to provide Non-Spinning Reserve are available for Dispatch throughout the Settlement Period for which they have been scheduled.

ASRP 5.5 SC's Obligation for Operating Reserve

ASRP 5.5.1 Obligation for Spinning and Non-Spinning Reserve

Except for the requirement for Non-Spinning Reserve referred to in paragraph ASRP 5.5.2, each Scheduling Coordinator's Operating Reserve obligation ~~in each Zone~~ shall be pro rata based upon the same proportion as the product of its percentage obligation based on metered output and the sum of its metered Demand and firm exports bears to the total of such products for all Scheduling Coordinators ~~in the Zone~~. The Scheduling Coordinator's percentage obligation based on metered output shall be calculated based on WSCC MORC criteria.~~as the sum of 5% of its Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from hydroelectric resources plus 7% of its Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from non-hydroelectric resources in that Zone.~~

ASRP 5.5.2 Additional Non-Spinning Reserve Requirements

Additional Non-Spinning Reserve required pursuant to ASRP 5.2(a) and (b) is the responsibility of the Scheduling Coordinator implementing such Schedules and is in addition to the obligation provided in paragraph ASRP 5.5.1.

ASRP 5.6 Standard for Spinning Reserve: Control

Each provider of Spinning Reserve must be capable of receiving a Dispatch instruction within one minute from the time the ISO Control Center elects to Dispatch the Spinning Reserve resource and must ensure that its resource can be at the Dispatched operating level within ten minutes after issue of the Dispatch instruction.

ASRP 5.7 Standard for Non-Spinning Reserve: Control

Each provider of Non-Spinning Reserve must be capable of receiving a Dispatch instruction within one minute from the time the ISO Control Center elects to Dispatch the Non-Spinning Reserve resource and must ensure that its resource can be at the Dispatched operating level or condition within ten minutes after issue of the Dispatch instruction.

ASRP 5.8 Standard for Operating Reserve: Procurement

ASRP 5.8.1 Procurement of Non Self-Provided Operating Reserve

Operating Reserve necessary to meet ISO requirements not met by self-provided Operating Reserve will be procured by the ISO as described in the ISO Tariff.

ASRP 5.8.2 Procurement Not Limited to ISO Control Area

The ISO will procure Spinning and Non-Spinning Reserves from Generating Units operating within the ISO Control Area and external imports of System Resources.

ASRP 5.8.3 Spinning Reserve Certification and Testing Requirements

Spinning Reserve may only be provided from

(1) Generating Units;

(2) System Resources from external imports; or

(3) System Units;

which have been certified and tested by the ISO using the process defined in Appendix B to this Protocol.

ASRP 5.8.4 Non-Spinning Reserve Certification and Testing Requirements

Non-Spinning Reserve may only be provided from resources including

(1) Loads;

(2) Generating Units;

(3) System Resources from external imports; and

(4) System Units;

which have been certified and tested by the ISO using the process defined in Appendix C to this Protocol.

ASRP 5.8.5 Self Provision of Operating Reserve

Scheduling Coordinators may self provide Spinning and Non-Spinning Reserves from resources outside the ISO Control Area.

ASRP 6 ~~REPLACEMENT RESERVE STANDARDS~~ [NOT USED]

ASRP 6.1 ~~Standard for Replacement Reserve: Quantity Needed~~[NOT USED]

ASRP 6.1.1 ~~Basis for Standard~~[NOT USED]

~~The ISO needs sufficient Replacement Reserve to be available to allow restoration of Dispatched Operating Reserve within sixty minutes to its Set Point scheduled for the Settlement Period concerned.~~

ASRP 6.1.2 **~~Replacement Reserve Requirements~~[NOT USED]**

~~The ISO shall have discretion to determine the quantity of Replacement Reserve it requires in each Zone. The ISO shall~~

~~make its determination of the required quantity of Replacement Reserve based on:~~

~~(a) analysis of the deviation between aggregate forecast Demands supplied by Scheduling Coordinators and that forecast by ISO;~~

~~(b) analysis of patterns of unplanned Generating Unit Outages;~~

~~(c) analysis of patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand;~~

~~(d) analysis of patterns of unexpected transmission Outages;~~

~~(e) analysis of seasonal variations that may require additional Replacement Reserves; and~~

~~(f) other factors influencing the ISO Controlled Grid's ability to meet Applicable Reliability Criteria.~~

ASRP 6.2 **~~Standard for Replacement Reserve: Performance~~**[NOT USED]

ASRP 6.2.1 **~~Replacement Reserve Supply Capability~~**[NOT USED]

~~Each resource providing Replacement Reserve must be capable of supplying any level of output up to and including its full reserved capacity within sixty minutes after issue of Dispatch instructions by the ISO.~~

ASRP 6.2.2 **~~Replacement Reserve Availability~~**[NOT USED]

~~Each resource providing Replacement Reserve must be capable of sustaining the instructed output for at least two hours.~~

ASRP 6.2.3 **~~Resources already Providing Ancillary Service~~**[NOT USED]

~~Replacement Reserve may be supplied from resources already providing another Ancillary Service, such as Spinning Reserve, but only to the extent that the ability to provide the other Ancillary Service is not restricted in any way by the provision of Replacement Reserve. The sum of Ancillary Service capacity supplied by the same resource cannot exceed the capacity of said resource.~~

ASRP 6.3 **~~Scheduling Coordinator's Obligation for Replacement Reserve~~**[NOT USED]

~~Scheduling Coordinator's Obligation for Replacement Reserve for each Settlement Period of the Day-Ahead Market and for each Hour-Ahead Market in each zone shall be based upon the ratio of the metered Demand (excluding exports) by each Scheduling Coordinator in each identified Zone for that Settlement Period to the total metered Demand (excluding exports) for that Settlement Period in that Zone.~~

ASRP 6.4 **~~Standard for Replacement Reserve: Control~~**[NOT USED]

~~Each provider of Replacement Reserve must be capable of receiving a Dispatch instruction within one minute from the time the ISO Control Center elects to Dispatch the Replacement Reserve resource and must ensure that its resource can be at the Dispatched operating level or condition within sixty minutes after issue of the Dispatch instruction.~~

ASRP 6.5 **~~Standard for Replacement Reserve: Procurement~~[NOT USED]**

ASRP 6.5.1 **~~Procurement of Non Self-Provided Replacement Reserve~~[NOT USED]**

~~Replacement Reserve necessary to meet ISO requirements not met by self-provided Replacement Reserve will be procured by the ISO as described in the ISO Tariff.~~

ASRP 6.5.2 **~~Procurement Not Limited to ISO Control Area~~[NOT USED]**

~~The ISO will procure Replacement Reserves from Generating Units operating within the ISO Control Area and external imports of System Resources.~~

ASRP 6.5.3 **~~Self Provision of Replacement Reserve~~[NOT USED]**

~~Scheduling Coordinators may self provide Replacement Reserves as external imports from System Resources located outside the ISO Control Area.~~

ASRP 6.5.4 **~~Certification and Testing Requirements~~[NOT USED]**

~~Replacement Reserve may only be provided from resources including~~

~~(1) Loads;~~

~~(2) Generating Units;~~

~~(3) System Resources from external imports; and~~

~~(4) System Units~~

~~which have been certified and tested by the ISO using the process defined in Appendix C to this Protocol.~~

ASRP 7 **VOLTAGE SUPPORT STANDARDS**

ASRP 7.1 **Standard for Voltage Support: Quantity Needed**

The ISO shall determine on a daily basis for each Settlement Period for each Trading Day the quantity and location of Voltage Support required to maintain voltage levels and reactive margins within WSCC and NERC criteria using a power flow study based on the quantity and location of Demand scheduled in each Settlement Period of the Day-Ahead Market. The ISO shall issue daily voltage schedules (Dispatch instructions) to Generators, Participating TOs and UDCs for each Trading Day, which are required to be maintained for ISO Controlled Grid reliability.

ASRP 7.2 **Standard for Voltage Support: Performance**

ASRP 7.2.1 **Automatic Voltage Regulation Requirement**

A Generating Unit providing Voltage Support must be under the control of generator automatic voltage regulators throughout the time period during which Voltage Support is required to be provided. A Generating Unit may be required to operate underexcited (absorb reactive power) at periods of light system Demand to avoid potential high voltage conditions, or overexcited (produce reactive power) at periods of heavy system Demand to avoid potential low voltage conditions.

ASRP 7.2.2 Compensation for Operating Outside of Range

The ISO will not compensate Generators for operating their Generating Units within the power factor band of 0.90 lag to 0.95 lead. If the ISO requires additional Voltage Support in the short term it may instruct a reduction in a Generating Unit's MW output so that it operates outside its specified power factor range. The ISO will compensate Generators for this service as provided in the ISO Tariff.

ASRP 7.3 Standard for Voltage Support: Distribution and Location

Each Generator, Participating TO and UDC shall ensure that sufficient Voltage Support is available in the vicinity of each designated substation bus to maintain voltage within the Voltage Limits prescribed by the ISO in its voltage schedules for each Settlement Period. Each Generator, Participating TO and UDC shall provide sufficient reactive supply in each local area to take into account real power losses created by reactive power flow on the system. Reactive power flow at Scheduling Points shall be maintained within a power factor bandwidth of 0.97 lag to 0.99 lead.

ASRP 7.4 Standard for Voltage Support: Control

Generating Units providing Voltage Support must have automatic voltage regulators which can correct the bus voltages to be within the prescribed voltage limits and within the machine capability in less than one minute.

ASRP 7.5 Standard for of Voltage Support: Procurement

ASRP 7.5.1 Long Term Voltage Support

As of the ISO Operations Date, the ISO will contract for long term Voltage Support service with Owners of Reliability Must-Run Units under Reliability Must-Run Contracts.

ASRP 7.5.2 Certification and Testing Requirements

Voltage Support may only be provided from resources including Loads, Generating Units and System Units which have been certified and tested by the ISO using the process defined in Appendix E to this Protocol.

ASRP 8 BLACK START STANDARDS

ASRP 8.1 Standard for Black Start: Quantity Needed

ASRP 8.1.1 Determination of Black Start Capability

The ISO shall determine the amount and location of Black Start capability it requires by reference to contingency studies which will be used as the basis of the ISO's emergency plans.

ASRP 8.1.2 Factoring in Failed Starts

The ISO shall, in determining the quantity needed, account for the probability that some Black Start Generating Units may fail to start or that transmission system damage may prevent some Black Start Generating Units from serving their intended loads.

ASRP 8.1.3 Submission of Load Restoration Time Requirements

Scheduling Coordinators shall provide the ISO with their load restoration time requirements for any resources that provide emergency services.

ASRP 8.2 Standard for Black Start: Performance

ASRP 8.2.1 10-Minute Start-Up Capability

Each Black Start Generating Unit must be able to start up with a dead primary and station service bus within ten minutes of issue of a Dispatch instruction by the ISO requiring a Black Start.

ASRP 8.2.2 Reactive Capability

Each Black Start Generating Unit must provide sufficient reactive capability to keep the energized transmission bus voltages within emergency voltage limits over the range of no-load to full load.

ASRP 8.2.3 12-Hour Minimum Output Capability

Each Black Start Generating Unit must be capable of sustaining its output for a minimum period of 12 hours from the time when it first starts delivering Energy.

ASRP 8.3 Standard for Black Start: Location

The ISO will select Black Start capacity in locations where adequate transmission capacity can be made readily available (assuming no transmission damage) to connect the Black Start Generating Unit to the station service bus of a Generating Unit designated by the ISO.

ASRP 8.4 Standard for Black Start: Control

ASRP 8.4.1 Voice Communication Requirement

Each supplier of Black Start capability must ensure that normal and emergency voice communications are available to permit effective Dispatch of the Black Start capability.

ASRP 8.4.2 ISO Confirmation

No load served by the Black Start Generating Unit or by any designated Generating Unit or by any transmission facility used for Black Start service may be restored until the ISO has confirmed that the need for such service has passed.

ASRP 8.5 Standard for Black Start: Procurement

ASRP 8.5.1 Initial Procurement

Black Start capability will initially be procured by the ISO through individual contracts with Scheduling Coordinators for Reliability Must-Run Units and other Generating Units which have Black Start capability.

ASRP 8.5.2 Certified Generating Units Requirement

Black Start capability may only be provided from Generating Units which have been certified and tested by the ISO using the process defined in Appendix F to this Protocol.

ASRP 9 TESTING FOR STANDARD COMPLIANCE

The ISO shall periodically conduct unannounced tests of resources providing Ancillary Services to confirm the ability of such resources to meet the applicable Ancillary Service standard for performance and control. Scheduling Coordinators for Ancillary Service resources being tested will be compensated for Energy output or Demand reduction provided pursuant to such tests in accordance with the ISO Tariff.

ASRP 9.1 Compliance Testing for Regulation

The ISO may test the capability of any Generating Unit or System Resource providing Regulation by using the ISO EMS to move that Generating Unit's or System Resource's output over the full range of its Regulation capacity within a ten-minute period.

ASRP 9.2 Compliance Testing for Spinning Reserve

The ISO may test the capability of any Generating Unit, System Unit or external import of a System Resource providing Spinning Reserve by issuing unannounced Dispatch I~~i~~nstructions requiring the Generating Unit, System Unit or external import of a System Resource to ramp up to its stated ten minute capability in accordance with the Scheduling Coordinator's Bid. Such tests may not necessarily occur on the hour. The ISO shall measure the response of the Generating Unit, System Unit or external import of a System Resource to determine compliance with its stated capabilities.

ASRP 9.3 Compliance Testing for Non-Spinning Reserve

ASRP 9.3.1 Compliance Testing of a Generating Unit, System Unit or System Resource

The ISO may test the Non-Spinning Reserve capability of a Generating Unit, System Unit or an external import of a System Resource by issuing unannounced Dispatch I~~i~~nstructions requiring the Generating Unit or System Unit to come on line and ramp up or, in the case of a System Resource, to affirmatively respond to real-time interchange schedule adjustment; all in accordance with the Scheduling Coordinator's bid. Such tests may not necessarily occur on the hour. The ISO shall measure the response of the Generating Unit, System Unit or external import of a System Resource to determine compliance with its stated capabilities.

ASRP 9.3.2 Compliance Testing of Dispatchable Load~~Curtailable Demand~~

The ISO may test the Non-Spinning Reserve capability of a Load providing Dispatchable Load~~Curtailable Demand~~ by issuing unannounced Dispatch instructions requiring the operator of the Load to report the switchable Demand of that Load actually being served by the operator at the time of the instruction. No Load will be disconnected as part of the test.

ASRP 9.4 ~~Compliance Testing for Replacement Reserve~~[Not Used]

ASRP 9.4.1 [Not Used] ~~Compliance Testing of a Generating Unit or System Resource~~

~~The ISO may test the Replacement Reserve capability of a Generating Unit, System Unit or an external import of a System Resource by issuing unannounced Dispatch instructions requiring the Generating Unit or System Unit to come on line and ramp up or, in the case of a System Resource, to affirmatively respond to a real-time interchange schedule adjustment; all in accordance with the Scheduling Coordinator's bid. Such tests may not necessarily occur on the hour. The ISO shall measure the response of the Generating Unit, System Unit or external import of a System Resource to determine compliance with its stated capabilities.~~

ASRP 9.4.2 [Not Used] ~~Compliance Testing of a Curtailable Demand~~

~~The ISO may test the Replacement Reserve capability of a Load providing Curtailable Demand by issuing unannounced Dispatch instructions requiring the operator of the Load to report the switchable Demand of that Load actually being served by the operator at the time of the instruction. No Load will be disconnected as part of a test.~~

ASRP 9.5 Compliance Testing for Voltage Support

ASRP 9.5.1 Compliance Testing of a Generating Unit

The ISO may test the Voltage Support capability of a Generating Unit by issuing unannounced Dispatch I~~i~~nstructions requiring the Generating Unit to adjust its power factor outside the specified power factor band of 0.90 lag to 0.95 lead, but within the limits of the Generating Unit capability curve.

ASRP 9.5.2 Compliance Testing of Other Reactive Devices

The ISO may test the Voltage Support capability of other reactive devices (shunt capacitors, static var compensators, synchronous condensers) by issuing unannounced Dispatch I~~i~~nstructions requiring operation of such devices.

ASRP 9.6 Compliance Testing for Black Start

The ISO may test the Black Start capability of a Generating Unit by unannounced tests, which may include issuing Dispatch

I~~i~~nstructions to start and synchronize the resource, testing of all communications circuits, simulating switching needed to connect the Black Start Generating Unit to the transmission system, and testing the features unique to each facility that relate to Black Start service.

ASRP 9.7 Consequences of Failure to Pass Compliance Testing

ASRP 9.7.1 Notification of Compliance Testing Results

If a Generating Unit, Load, or System Resource fails a compliance test, the ISO shall notify the Scheduling Coordinator whose resource was the subject of the test and the Ancillary Service Provider or owner or operator of a System Resource providing Ancillary Services of such failure by any means as soon as reasonably practicable after the completion of the test. In addition, regardless of the outcome of the test, the ISO shall provide the Scheduling Coordinator whose resource was subject to a compliance test written notice of the results of such test. The ISO shall at the same time send a copy of the notice to the Ancillary Service Provider or owner or operator of a System Resource providing Ancillary Services.

ASRP 9.7.2 Penalties for Failure to Pass Compliance Testing

The Scheduling Coordinator whose resource fails a compliance test shall be subject to the financial penalties provided for in the ISO Tariff. In addition, the ISO shall institute the sanctions described in ASRP 11.

ASRP 10 PERFORMANCE AUDITS FOR STANDARD COMPLIANCE

In addition to testing under ASRP 9, the ISO will periodically audit the performance of resources providing Ancillary Services to confirm the ability of such resources to meet the applicable Ancillary Service standard for performance and control.

ASRP 10.1 Performance Audit for Regulation

The ISO will audit the performance of a Generating Unit providing Regulation by monitoring its response to ISO EMS control or, in the case of an external import of a System Resource providing Regulation, by monitoring the dynamic interchange response to ISO EMS control around its Set Point within its rated MW/minute capability over the range of Regulation capacity scheduled for the current Settlement Period.

ASRP 10.2 Performance Audit for Spinning Reserve

The ISO will audit the performance of a Generating Unit or external import of a System Resource providing Spinning Reserve by auditing its response to Dispatch instructions and by analysis of Meter Data associated with the Generating Unit. Such audits may not necessarily occur on the hour. A Generating Unit providing Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move at the MW/minute capability stated in its bid, reach the amount of Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO, and respond to system frequency deviations outside the allowed frequency deadband. An external import of a System Resource providing Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move at the MW/minute capability stated in its bid, reach the amount of Spinning Reserve capacity scheduled for the current settlement Period within ten minutes of issue of the Dispatch instruction by the ISO.

ASRP 10.3 Performance Audit for Non-Spinning Reserve

The ISO will audit the performance of a Generating Unit, Load, or System Resource providing Non-Spinning Reserve by auditing its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. Such audits may not necessarily occur on the hour. A Generating Unit providing Non-Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity under the control of the ISO scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO. An external import of a System Resource providing Non-Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO. A Load providing Non-Spinning Reserve from Curtailable Demand shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruciton by the ISO.

ASRP 10.4 ~~Performance Audit for Replacement Reserve~~[NOT USED]

~~The ISO will audit the performance of a Generating Unit, Load, or System Resource providing Replacement Reserve by auditing its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. Such audits may not necessarily occur on the hour. A Generating Unit providing Replacement Reserve shall be evaluated on its ability to respond to a Dispatch instruction, start within the designated time delay, move at the MW/minute capability stated in its bid, reach the amount of Replacement Reserve capacity scheduled for the Settlement Period concerned within sixty minutes of issue of the Dispatch instruction, and sustain operation at this level for a sufficient time to assure availability over the specified period. An external import of a System Resource providing Replacement Reserve shall be evaluated on its ability to respond to a Dispatch instruction, start within the designated time delay, move at the MW/minute capability stated in its bid, reach the amount of Replacement Reserve capacity scheduled for the Settlement Period concerned within sixty minutes of issue of the Dispatch instruction, and sustain operation at this level for a sufficient time to assure availability over the specified period. A Load providing Replacement Reserve from Curtailable Demand shall be evaluated on its ability to respond to a Dispatch instruction, start within the designated time delay, move at the MW/minute capability stated in its bid, reach the amount of Replacement Reserve capacity scheduled for the Settlement Period concerned within sixty minutes of issue of the Dispatch instruction, and sustain operation at this level for a sufficient time to assure availability over the specified period.~~

ASRP 10.5 Performance Audit for Voltage Support

The ISO will audit the performance of a resource providing Voltage Support by auditing of its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. A resource providing Voltage Support shall be evaluated on its ability to provide reactive support over the stated power factor range of the resource, provide reactive support within the prescribed time periods, and demonstrate the effective function of automatic voltage control equipment for the amount of Voltage Support under the control of the ISO for the current Settlement Period.

ASRP 10.6 Performance Audit for Black Start

The ISO will audit the performance of a Black Start Generating Unit by analysis of Meter Data and other records to determine that the performance criteria relating to the Black Start from that Black Start Generating Unit were met when required.

ASRP 10.7 Consequences of Failure to Pass Performance Audits

ASRP 10.7.1 Notification of Performance Audit Results

The ISO shall give the Scheduling Coordinator for an Ancillary Service Provider whose resource was subject to a performance audit written notice of the results of such audit. The ISO will at the same time send a copy of the notice to the Ancillary Service Provider

ASRP 10.7.2 Penalties for Failure to Pass Performance Audit

The Scheduling Coordinator for an Ancillary Service Provider whose resource fails a performance audit shall be subject to the financial penalties provided for in the ISO Tariff. In addition the sanctions described in ASRP 11 shall come into effect.

ASRP 11 SANCTIONS FOR POOR PERFORMANCE

ASRP 11.1 Warning Notice

If an Ancillary Service resource fails a compliance test or a performance audit, the ISO will issue a warning notice to the Scheduling Coordinator for that resource and at the same time will send a copy of the notice to the owner and operator of the resource.

ASRP 11.2 Scheduling Coordinator's Option to Test

On receipt of a warning notice the Ancillary Service Provider for the resource concerned may request the ISO, through its Scheduling Coordinator, to test the capability of the Ancillary Service resource concerned. The ISO shall carry out such test as soon as practicable and the cost of such test shall be paid by the Scheduling Coordinator irrespective of the result of the test.

ASRP 11.3 Duration of Warning Notice

A warning notice shall continue in effect until:

(a) the Ancillary Service resource is next tested by the ISO whether such a test is called for by the Scheduling Coordinator under ASRP 11.2 or carried out by the ISO under ASRP 9; or

(b) the expiry of a period of six calendar months from the date upon which the ISO notified the Scheduling Coordinator that the Ancillary Service resource failed the test or the performance audit which gave rise to the issue of the warning notice, whichever is the earlier.

ASRP 11.4 Second failure

An Ancillary Service resource which fails a compliance test or a performance audit conducted during the period when a warning notice for that resource is in effect shall be disqualified immediately from providing the Ancillary Service concerned whether as part of the ISO's auction or as part of a self-provision arrangement, and shall not be permitted to submit a bid to the ISO or be part of a self provision arrangement until such time as it has successfully re-passed the approval and certification procedure described in the relevant Appendix to this ASRP.

ASRP 12 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

~~APPENDIX D~~

~~Certification for Replacement Reserve~~

~~**D 1**~~ ~~An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service from a Generating Unit or System Resource whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:~~

~~**D 1.1**~~ ~~the rated capacity of the Generating Unit or System Resource must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;~~

~~**D 1.2**~~ ~~the operator of the Generating Unit must be able to increase output as quickly as possible to a value indicated in a Dispatch instruction, reaching the indicated value in sixty minutes or less after issue of the instruction.~~

~~**D 2**~~ ~~An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service from Curtailable Demand whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:~~

~~**D 2.1**~~ ~~the operator must be able to completely disconnect the required Load pursuant to a Dispatch instruction within sixty minutes after issue of the instruction;~~

~~**D 2.2**~~ ~~the minimum change in the electrical consumption of the Load must be at least 1 MW; and~~

~~**D 2.3**~~ ~~the Load must be capable of being interrupted for at least two hours.~~

~~**D 3**~~ ~~An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service, whether pursuant to the ISO's auction or as part of a self-provision arrangement, must also meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:~~

~~**D 3.1**~~ ~~the operator of the Generating Unit, System Resource or the Curtailable Demand must have a means of receiving a Dispatch instruction to initiate an increase in real power output or a reduction in Demand (MW) within one minute of the ISO Control Center's determination that Replacement Reserve capacity must be Dispatched; and~~

~~**D 3.2**~~ ~~the communication system and the Generating Unit or Load must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Replacement Reserve.~~

~~**D 4**~~ ~~An Ancillary Service Provider wishing to be considered for certification for Replacement Reserve service must make a written request to the ISO, giving details of the technical capability of the Generating Unit, System Resource or the Load concerned and identifying the Scheduling Coordinator through whom the Ancillary Service Provider intends to offer Replacement Reserve. The Ancillary Service Provider shall at the~~

~~same time send a copy of its request to that Scheduling Coordinator. Technical Review request forms will be available from the ISO.~~

~~**D 5**~~ ~~No later than one week after receipt of the Ancillary Service Provider's request, the ISO shall provide the Ancillary Service Provider with a listing of acceptable communication options and interface equipment options for Replacement Reserve. The ISO shall send a copy of the listing to the Ancillary Service Provider's Scheduling Coordinator.~~

~~**D 6**~~ ~~The Ancillary Service Provider may elect to implement any of the options defined by the ISO, and, if it wishes to proceed with its request for certification, the Ancillary Service Provider shall give written notice to the ISO of its selected communication option and interface equipment option, with a copy to its Scheduling Coordinator.~~

~~**D 7**~~ ~~When it receives the Ancillary Service Provider's notice, the ISO shall notify the Ancillary Service Provider and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment the Ancillary Service Provider may proceed as indicated below to secure the necessary facilities and capabilities required.~~

~~**D 8**~~ ~~The Ancillary Service Provider may also propose alternatives that it believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.~~

~~**D 9**~~ ~~The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision shall be provided not later than six weeks after the proposal is received by the ISO. The Ancillary Service Provider and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.~~

~~**D 10**~~ ~~Upon agreement as to the method of communication and control to be used by the Ancillary Service Provider, the ISO shall provisionally approve the proposal in writing providing a copy to the Ancillary Service Provider's Scheduling Coordinator at the same time. The Ancillary Service Provider may then proceed to procure and install the equipment and make arrangements for the required communication.~~

~~**D 11**~~ ~~Design, acquisition, and installation of the Ancillary Service Provider's equipment shall be under the control of the Ancillary Service Provider. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to the ISO's equipment at its own cost.~~

~~**D 12**~~ ~~The Ancillary Service Provider shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.~~

~~**D 13**~~ ~~When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Ancillary Service Provider shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Ancillary Service Provider's request, accept a proposed time if possible or suggest at least three alternatives. If the ISO responds by suggesting alternatives, the Ancillary Service Provider shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Ancillary Service Provider shall inform its Scheduling Coordinator of the agreed date and time of the test.~~

~~**D 14**~~ ~~Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:~~

~~**D 14.1**~~ ~~confirmation of control communication path performance;~~

~~**D 14.2**~~ ~~confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;~~

~~**D 14.3**~~ ~~confirmation of the Generating Unit, System Resource or Load control performance; and~~

~~**D 14.4**~~ ~~confirmation of the range of Generating Unit or System Resource control to include changing the Generating Unit output over the range of Replacement Reserve proposed.~~

~~**D 15**~~ ~~Upon successful completion of the test the ISO shall certify the Generating Unit, System Resource or Load as being permitted to provide Replacement Reserve as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its data base to reflect the permission for the Generating Unit or Load to provide Replacement Reserve service.~~

~~**D 16**~~ ~~The Scheduling Coordinator may bid Replacement Reserve service from the certified Generating Unit or Load into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the second Trading Day after the ISO issues the certificate.~~

~~**D 17**~~ ~~The certification to provide Replacement Reserve shall remain in force until withdrawn by the Scheduling Coordinator or the Ancillary Service Provider by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.~~

~~**D 18**~~ ~~The certification may be revoked by the ISO only under provisions of the ASRP or the ISO Tariff.~~

DEMAND FORECASTING PROTOCOL

* * *

DFP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meaning set opposite them:

"Annual Peak Demand Forecast" means a Demand Forecast of the highest Hourly Demand in any hour in a calendar year, in MW.

~~**"Congestion Zone"** means a Zone identified as an Active Zone in Appendix I of the ISO Tariff.~~

"Hourly Demand" means the average of the instantaneous Demand integrated over a single clock hour, in MW.

"ISO Home Page" means the ISO internet home page at http://www.caiso.com/~~iso~~ or such other internet address as the ISO shall publish from time to time.

"Weekly Peak Demand Forecast" means a Demand Forecast of the highest Hourly Demand in any hour in a period beginning at the start of the hour ending 0100 on Sunday and ending at the end of the hour ending 2400 the following Saturday, in MW.

* * *

DFP 2.1 Data to be Submitted to the ISO by SCs

At the time specified in DFP 2.3, each SC shall submit to the ISO its Weekly Peak Demand Forecast by ~~Congestion Zone~~ **Location** reflecting (1) the Weekly Peak Demand Forecasts of the UDCs that it proposes to Schedule and (2) any other non-UDC Demand that it proposes to Schedule. All Weekly Peak Demand Forecasts submitted shall include Demand Forecasts for the following 52 weeks.

* * *

DFP 3.1 Data to be Submitted to the ISO by UDCs

At the time specified in DFP 3.3, each UDC shall submit to the ISO its Weekly Peak Demand Forecasts by ~~Congestion Zone~~ **Location** reflecting the Weekly Peak Demand Forecast for load expected to be served by facilities under the control of the UDC. All Weekly Peak Demand Forecasts submitted shall include Demand Forecasts for the following 52 weeks.

* * *

DFP 4.1 Advisory Control Area Demand Forecasts

The ISO will publish on WEnet and supply to the SCs advisory Control Area Demand Forecasts comprised of Hourly Demand Forecasts for each ~~Congestion Zone~~ **Location** for each Settlement Period of the relevant Trading Day. The ISO will publish this information in accordance with the timing requirements set forth in the SP.

* * *

DISPATCH PROTOCOL

DISPATCH PROTOCOL

Table of Contents

DISPATCH PROTOCOL (DP)

DP 1 OBJECTIVES, DEFINITIONS AND SCOPE

DP 1.1 Objectives

The objectives of this Protocol are:

(a) to implement those sections of the ISO Tariff which involve real time and emergency operations;

(b) to describe the real time Dispatch of the Ancillary Services specified in the Ancillary Services Requirements Protocol (ASRP);

(c) to describe the operational activities of the ISO after all commitments have been made in the Hour-Ahead Market as described in the Scheduling Protocol (SP);

(d) to describe the use of Supplemental Energy bids~~ received by the ISO in accordance with the Schedules and Bids Protocol (SBP)~~; and

(e) to describe how the ISO will meet the operational requirements of NERC and WSCC guidelines.

DP 1.2 Definitions

DP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to DP are to this Protocol or to the stated paragraph of this Protocol.

DP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Backup ISO Control Center" means the ISO Control Center located in Alhambra, California.

~~**"BEEP"** means the Balancing Energy and Ex-Post Pricing software referred to in SP 11.2 which is used to determine the merit order stack.~~

"Control Area Operator" means the person responsible for managing the real time operations of a Control Area.

"Dispatch Instruction" means an operating order that is issued by the ISO to a Participant pertaining to real time operations.

"GCC" means the single point of contact at the grid control center of Southern California Edison Company.

"ISO Home Page" means the ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time.

"Primary ISO Control Center" means the ISO Control Center located in Folsom, California.

"Participant" means any of those entities referred to in DP 1.3.1(a)-(f).

"Power System Stabilizer (PSS)" means an electronic control system applied on a Generating Unit that helps to damp out dynamic oscillations on a power system. The PSS senses Generator variables, such as voltage, current and shaft speed, processes this information and sends control signals to the Generator voltage regulator.

"Qualifying Facility" means a qualifying co-generation or small power production facility recognized by FERC.

"SCED" refers to the Security Constrained Economic Dispatch program described in Section 31.4.3.2.2.1 that is used to economically Dispatch resources in Real-Time.

"Security Coordinator" means the person responsible for Security Monitoring in real time for the California Area.

"TOC" means the single point of contact at the transmission operations center of Pacific Gas & Electric Company.

"Total Transfer Capability (TTC)" means the amount of power that can be transferred over an interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre-contingency and post-contingency system conditions.

"Western Interconnection" means a network of transmission lines embodied within the WSCC Region.

DP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) Time references in this Protocol are references to prevailing Pacific time.

DP 1.3 Scope

DP 1.3.1 Scope of Application to Parties

This Protocol applies to the ISO and to the Participants:

(a) Scheduling Coordinators (SCs);

(b) Utility Distribution Companies (UDCs);

(c) Participating Transmission Owners (PTOs);

(d) Participating Loads;

(~~d~~e) Participating Generators;

(~~e~~f) Control Area Operators, to the extent the agreement between the Control Area Operator and the ISO so provides; and

(g) Metered Subsystem (MSS) Operators.

DP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

DP 2 STANDARDS TO BE OBSERVED

DP 2.1 Applicable Reliability Criteria

The ISO shall exercise Operational Control over the ISO Controlled Grid in compliance with all Applicable Reliability Criteria. Applicable Reliability Criteria are defined as the standards established by NERC, WSCC and Local Reliability Criteria and include the requirements of the Nuclear Regulatory Commission (NRC).

DP 2.1.1 WSCC Criteria (Standards)

(a) Western Interconnection

The WSCC set of standards for the Western Interconnection, which are based on the NERC standards. The WSCC further defines procedures and policies applicable to the Western Interconnection. WSCC guidelines include:

(i) Part 1 – Reliability Criteria for Transmission System Planning

(ii) Part 2 – Power Supply Design Criteria

(iii) Part 3 – Minimum Operating Reliability Criteria (MORC)

(iv) Part 4 – Definitions

(b) Operating Procedures

The WSCC Operating Procedures submitted to WSCC by individual utilities and the ISO to address specific operating problems in their respective grids that could affect operations of the interconnected grid.

(c) Dispatcher's Handbook

The WSCC Dispatcher's Handbook supplied by WSCC to all utilities and Control Areas as a reference for dispatchers to use during normal and emergency operations of the grid.

DP 2.1.2 NERC Policies and Standards

(a) National Standards

The NERC national level standards for all utilities to follow to allow for safe and reliable operation of electric systems.

(b) Operating Manual

The NERC Operating Manual supplied by NERC to all utilities and Control Areas as a reference for dispatchers to use during normal and emergency operations of the grid.

DP 2.1.3 Local Reliability Criteria (Standards)

The reliability criteria unique to the transmission systems of each of the PTOs established at the later of: (1) the ISO Operations Date or (2) the date upon which a new Participating TO places its facilities under the control of the ISO. Each Participating TO must provide its Local Reliability Criteria to the ISO, as required by the TCA.

DP 2.1.4 NRC (Standards)

The reliability standards published by the NRC from time to time.

DP 2.2 Ancillary Services

The ISO will base its standards for the Dispatch of Ancillary Services upon WSCC MORC and ISO Controlled Grid reliability requirements.

DP 2.3 ISO Standards

The ISO Governing Board may establish guidelines more stringent than those established by NERC and WSCC as needed for the secure and reliable operation of the ISO Controlled Grid.

DP 2.4 Good Utility Practice (Standards)

When the ISO is exercising Operational Control of the ISO Controlled Grid, the ISO and Participants shall comply with Good Utility Practice. The ISO Tariff defines Good Utility Practice which, for ease of use of the DP, is repeated as follows:

> "Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgement in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region."

DP 2.5 Existing Contracts

The ISO will implement Sections 2.4.3 and 2.4.4 of the ISO Tariff with respect to Existing Contracts after the close of the Hour-Ahead Market and in real time.

DP 2.6 The Role of Participants

In issuing the Dispatch Instructions, the ISO will not intentionally request UDCs, Participating Generators, Generating Unit operators, or SCs 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.

DP 3 SCHEDULING AND REAL TIME INFORMATION

DP 3.1 Final Schedules

The scheduling process described in the SP 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. The Final Schedule will include information with respect to:

(a) Generation schedules;

(b) Demand schedules;

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

(d) Ancillary Services schedules, based on SCs' 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.

DP 3.2 Supplemental Energy Bids

In addition to the Final Schedules, Supplemental Energy bids will be available to the ISO real time dispatchers, as described in ~~the SBP and~~ Section 31.4.1.2 of the ISO Tariff for the SCED~~by forty-five (45) minutes prior to the start of the Settlement Period to which such Supplemental Energy bids apply~~.

DP 3.3 SC Intertie Schedules

In accordance with the SBP and the SP, SCs shall provide the ISO with Interconnection schedules prepared in accordance with all NERC, WSCC and ISO requirements. The provisions of the SBP and the SP shall apply to real time changes in Interconnection schedules under Existing Contracts.

DP 3.4 Information to be Supplied by SCs

DP 3.4.1 SC Dispatch

Each SC shall be responsible for the scheduling and Dispatch of Generation and Demand in accordance with its Final Schedule.

DP 3.4.2 Generator or Interconnection Schedule Change

Each SC 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 SC shall immediately pass to the ISO any information which it receives from a Generator which the Generator provides to the SC pursuant to DP 3.7. Each SC shall immediately pass to the ISO any information it receives from a MSS Operator. ~~which the MSS Operator provides to the SC pursuant to DP 3.9~~

DP 3.4.3 Verbal Communication with Generators

Normal verbal communication of Dispatch Instructions between the ISO and Generators will be via the relevant SC. Each SC must immediately pass on to the Generator concerned any verbal communication for the Generator which it receives from the ISO. 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 SC. The ISO may, with the prior permissions of the Scheduling Coordinator concerned, communicate with and give Dispatch Instructions to the operators of Generating Units and Loads directly without having to communicate through their appointed Scheduling Coordinator. 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.

DP 3.4.4 Consequences of a Failure to Respond or Inadequate Response

The ISO may apply penalties (including the Uninstructed Deviation Penalties set forth in Section 11.2.4.1.2), fines, economic consequences or the sanctions referred to in DP 9.5.2 for any failure or inadequate response under DP 3.4.3 to the SC 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.

DP 3.5 Information to be Supplied by UDCs

DP 3.5.1 UDC Status Change

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.

DP 3.5.2 UDC Outage Scheduling

Each UDC shall schedule all equipment Outages (or Outages of other equipment that could affect the ISO Controlled Grid) at the point of interconnection with the ISO using the appropriate Outage scheduling procedures described in the OCP.

DP 3.5.3 UDC Outage Emergency Scheduling

Each UDC shall coordinate any requests for emergency Outages on point of interconnection equipment directly with the appropriate ISO Control Center as specified in DP 6.2.

DP 3.6 Information to be Supplied by PTOs

DP 3.6.1 Transmission Status Change

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.

DP 3.6.2 Transmission Outage Scheduling

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 procedure under the OCP.

DP 3.6.3 PTO Emergency Outage Scheduling

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 DP 6.2.

DP 3.7 Information to be Supplied by Generators

DP 3.7.1 Generator Status Change

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

DP 3.7.2 Generator Schedules

In the event that a Generator cannot meet its Generation schedule, whether due to a Generating Unit trip or the loss of a piece of equipment causing a reduction in capacity or output, the Generator shall notify the ISO, through its SC at once. If a Generator will not be able to meet a time commitment or requires the cancellation of a Generating Unit start up, it shall notify the ISO, through its SC at once.

DP 3.8 Information to be Supplied by Control Area Operators

DP 3.8.1 System Status Change

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 WSCC Regional Security Plan, shall keep the ISO informed of all information required by WSCC for use by the Security Coordinator.

DP 3.8.2 Scheduling Procedure

The ISO and each adjacent Control Area Operator shall follow all applicable NERC and WSCC 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 WSCC standard procedures.

DP 3.8.3 Data Exchange

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.

DP 3.8.4 Operational Metering

All provisions in this section DP 3.8 refer to information and data obtained from metering used for Control Area operations and not metering used for billing and settlement.

DP 3.9 [Not Used]

DP 3.9.1 [Not Used]

DP 3.9.2 [Not Used]

DP 3.9.3 [Not Used]

DP 3.9.4 [Not Used]

DP 3.9.5 [Not Used]

DP 4 METHODS OF COMMUNICATIONS

DP 4.1 Methods of Transmitting Dispatch Instructions

DP 4.1.1 Full-Time Communications Facility Requirement

Each Participant must provide a communications facility manned twenty-four (24) hours a day, seven (7) days a week capable of receiving Dispatch Instructions issued by the ISO.

DP 4.2 Recording of Dispatch Instructions

The ISO shall maintain records of all electronic, fax and verbal communications related to a Dispatch instruction. The ISO shall maintain a paper or electronic copy of all Dispatch instructions delivered by fax and all Dispatch instructions delivered electronically. The ISO shall record all voice conversations that occur related to Dispatch instructions on the Dispatch Instruction communication equipment. These records, copies and recordings may be used by the ISO to audit the Dispatch Instruction, and to verify the response of the Participant concerned to the Dispatch Instruction.

DP 4.3 Contents of Dispatch Instructions

Dispatch Instructions shall include the following information as appropriate:

(a) exchange of operator names;

(b) specific resource being dispatched;

(c) specific MW value and price point of the resource being dispatched;

(d) specific type of instruction (action required);

(e) time the resource is required to begin initiating the Dispatch Instruction;

(f) time the resource is required to achieve the Dispatch Instruction;

(g) time of notification of the Dispatch Instruction; and

(h) any other information which the ISO considers relevant.

DP 4.4 Acknowledgement of Dispatch Instructions

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. Dispatch Instructions of Imbalance Energy will be deemed delivered and settled ~~as such~~in accordance with Sections 31.4.3.3 and 31.4.3.4 of the ISO Tariff.

DP 5 ISO FACILITIES AND EQUIPMENT

DP 5.1 ISO Facility and Equipment Outages

The ISO has installed redundant control centers, communication systems and computer systems. Most, but not necessarily all, equipment problems or failures should be transparent to Participants. This DP 5 addresses some situations when Participants could be affected, but it is impossible to identify and plan for every type of equipment problem or failure. Real time situations will be handled by the real time ISO dispatchers. The ISO control room in Folsom is the Primary ISO Control Center and the ISO control room in Alhambra is the Backup ISO Control Center.

DP 5.2 WEnet Unavailable

DP 5.2.1 Unavailable Critical Functions of WEnet

During a total disruption of the WEnet several critical functions of the ISO will not be available including:

(a) the Scheduling Infrastructure (SI) computer will not be able to communicate with SCs to receive any type of updated Schedule information;

(b) the SI computer will not be able to communicate Final Energy, Ancillary Services and Congestion ~~Management~~ information ~~and Schedule changes~~ to the SCs; and

(c) the ISO will not be able to communicate general information, including emergency information, to any Participants.

DP 5.2.2 Communications during WEnet Unavailability

During any period of WEnet unavailability, the ISO shall:

(a) make all reasonable efforts to keep Participants aware of current ISO Controlled Grid status using voice communications;

(b) use the most recent set of ~~Balanced~~ final Energy Schedules for each SC for the current and all future Settlement Periods and/or Trading Days until the WEnet is restored; and

(c) attempt to take critical Schedule changes from SCs via voice communications as time and manpower allows.

DP 5.3 Primary ISO Control Center – Loss of all Voice Communications

DP 5.3.1 Notification of Loss of Voice Communication

In the event of loss of all voice communication at the Primary ISO Control Center, the Primary ISO Control Center will use alternate communications to notify the Backup ISO Control Center of the loss of voice communications. The Backup ISO Control Center will notify Participants via OASIS or other means.~~post information on the situation on the WEnet~~. Additional voice notifications will be made as time permits.

DP 5.3.2 Notification of Restoration of Voice communication

Once voice communications have been restored to the Primary ISO Control Center, the ISO will notify Participants via ~~post this information on the~~ OASIS or other means.~~WEnet~~.

DP 5.4 Primary ISO Control Center – Control Center Completely Unavailable

DP 5.4.1 Notification of Loss of Primary ISO Control Center

In the event that the Primary ISO Control Center becomes completely unavailable, the Primary ISO Control Center will use alternate communications to notify the Backup ISO Control Center that the Primary ISO Control Center is unavailable. The Backup ISO Control Center will notify Participants via OASIS or other means.~~post information on the situation on the WEnet.~~ Additional voice notifications will be made as time permits.

DP 5.4.2 Backup ISO Control Center Response

The Backup ISO Control Center will notify Participants via OASIS or other means ~~post confirmation on the WEnet~~ that all computer systems are functioning normally (if such is the case) and take complete control of the ISO Controlled Grid. The Backup ISO Control Center will notify the TOC by direct voice communication of the situation.

DP 5.4.3 Notification of Restoration of Primary ISO Control Center

Once the Primary ISO Control Center is again available, all functions will be transferred back, and the Primary ISO Control Center will notify all Participants via OASIS~~the WEnet~~.

DP 5.5 Primary ISO Control Center - ISO Energy Management System (EMS) Unavailable

DP 5.5.1 Notification of Loss of EMS

Should an outage occur to the redundant EMS computer systems in the Primary ISO Control Center, an auto transfer should occur to transfer EMS operation to the redundant EMS back up computers at the Backup

ISO Control Center. Due to the severity of a total ISO EMS computer outage, the Primary ISO Control Center will notify Participants via OASIS or other means ~~post information on the WEnet~~ that the Primary ISO Control Center EMS computer is unavailable and that EMS control has been transferred to the Backup ISO Control Center.

DP 5.5.2 Notification of Restoration of EMS

When the Primary ISO Control Center EMS computer is restored, the Backup ISO Control Center will initiate a transfer back of the EMS system to the Primary ISO Control Center. The Primary ISO Control Center will notify Participants via OASIS or other means ~~post information on~~of ~~-~~the restored EMS computer system status~~ on the WEnet~~.~~.~~

DP 5.6 Backup ISO Control Center – Loss of all Voice Communications

DP 5.6.1 Notification of Loss of Voice Communication

In the event of a loss of all voice communications at the Backup ISO Control Center, the Backup ISO Control Center will use alternate communications to notify the Primary ISO Control Center of the loss of voice communications. The Primary ISO Control Center will notify Participants via OASIS or other means of ~~post information on~~ the situation~~ via the WEnet~~. Additional voice notifications will be made as time permits.

DP 5.6.2 Notification of Restoration of Voice Communication

Once voice communications have been restored to the Backup ISO Control Center, the Primary ISO Control Center will notify Participants via OASIS or other means~~post this information on the WEnet~~.

DP 5.7 Backup ISO Control Center – Control Center Completely Unavailable

DP 5.7.1 Notification of Loss of Backup ISO Control Center

In the event that the Backup ISO Control Center becomes completely unavailable, the Backup ISO Control Center will use alternate communications to notify the Primary ISO Control Center that the Backup ISO Control Center is unavailable. The Primary ISO Control Center will notify Participants via OASIS or other means~~post information on the situation on the WEnet~~. Additional voice notifications will be made as time permits.

DP 5.7.2 Primary ISO Control Center Response

The Primary ISO Control Center will notify Participants via OASIS or other means ~~post confirmation on the WEnet~~ that all computer systems are functioning normally (if such is the case) and take complete control of the ISO Controlled Grid. The Primary ISO Control Center will notify the SCE GCC by direct voice communications of the situation.

DP 5.7.3 Notification of Restoration of Backup ISO Control Center

Once the Backup ISO Control Center is again available all functions will be transferred back, and the Backup ISO Control Center will notify all Participants via OASIS~~the WEnet~~.

DP 5.8 Use of IOUs' Energy Control Center Computers

The ISO and the IOUs will comply with the procedures for the utilization by the ISO of the IOUs' Energy control center computers when developed. The ISO will post such procedures on the ISO Home Page~~the WEnet~~ when agreed.

DP 6 ROUTINE OPERATION OF THE ISO CONTROLLED GRID

DP 6.1 Overview/Responsibility

The ISO shall operate the ISO Controlled Grid in accordance with the standards described in DP 2 and within the limit of all applicable nomograms and established operating limits and procedures.

DP 6.2 ISO Controlled Facilities

DP 6.2.1 General

The ISO shall have Operational Control of all transmission lines and associated station equipment that have been transferred to the ISO Controlled Grid from the PTOs as listed in the ISO Register.

DP 6.2.2 Primary ISO Control Center

The Primary ISO Control Center shall have Operational Control over:

(a) all transmission lines greater than 230kV and associated station equipment on the ISO Controlled Grid;

(b) all Interconnections; and

(c) all 230 kV and lower voltage transmission lines and associated station equipment identified in the ISO Register as that portion of the ISO Controlled Grid located in the PG&E Service Area.

DP 6.2.3 Backup ISO Control Center

The Backup ISO Control Center shall have Operational Control over all 230 kV and lower voltage transmission lines and associated station equipment identified in the ISO Register as that portion of the ISO Controlled Grid located in the SCE and SDGE Service Areas.

DP 6.3 Clearing Equipment for Work

The clearance procedures of the ISO and the relevant UDC and PTO must be adhered to by all parties, to ensure the safety of all personnel working on ISO Controlled Grid transmission lines and equipment. In accordance with the OCP, no work shall start on any equipment or line which is under the Operational Control of the ISO unless final approval has first been obtained from the appropriate ISO Control Center. Prior to starting the switching to return any line or equipment to service the ISO shall confirm that all formal requests to work on the cleared line or equipment have been released.

DP 6.4 Equipment De-energized for Work

In some circumstances, System Reliability requirements may require a recall capability that can only be achieved by allowing work to proceed with the line or equipment de-energized only (i.e. not cleared and grounded). Any personnel working on such de-energized lines and equipment must take all precautions as if the line or equipment were energized. Prior to energizing any such lines or equipment deenergized for work, the ISO shall confirm that all formal requests to work on the de-energized line or equipment have been released.

DP 6.5 Hot-Line Work

The ISO has full authority to approve requests by PTOs to work on energized equipment under the Operational Control of the ISO, and no such work shall be commenced until the ISO has given its approval.

DP 6.6 Intertie Switching

The ISO and the appropriate single point of contact for the relevant PTO and the adjacent Control Area shall coordinate during the de-energizing or energizing of any Interconnection.

DP 6.7 Operating Voltage Control Equipment

DP 6.7.1 Operating Voltage Control Equipment Under ISO Control

The ISO will direct each PTO's single point of contact in the operation of voltage control equipment that is under the ISO's Operational Control.

DP 6.7.2 Operating Voltage Control Equipment Under UDC Control

Each UDC must operate voltage control equipment under UDC control in accordance with existing UDC voltage control guidelines.

DP 6.7.3 Special ISO Voltage Control Requirements

The ISO may request a PTO via its single point of contact or a UDC via its single point of contact to operate under special voltage control requirements from time to time due to special system conditions.

DP 6.8 Outages

The ISO will coordinate and approve Maintenance Outages and coordinate responses to Forced Outages of all transmission facilities in the ISO Controlled Grid and Reliability Must-Run Units in accordance with the OCP.

Any scheduled Outages that are cancelled by ISO real time operations due to system requirements must be rescheduled with the ISO Outage Coordination Department in accordance with the OCP.

DP 6.9 Security Monitoring

The ISO shall be the Regional Reliability~~Security~~ Coordinator for ~~the~~ California Mexico Reliability Center.~~Area~~. As Regional Reliability~~Security~~ Coordinator, the ISO, in conjunction with the other WSCC Regional Reliability~~Security~~ Coordinators, will be responsible for the stable and reliable operation of the Western Interconnection in accordance with the WSCC Regional Security Plan.

DP 6.9.1 Reliability~~Security~~ Coordinator

As Regional Reliability~~Security~~ Coordinator, the ISO may direct activities as appropriate to curtail Schedules, Dispatch Generation or impose transfer limitations as necessary to relieve grid Congestion, mitigate potential overloads or eliminate operation outside of existing nomogram criteria.

DP 6.9.2 Authority of WSCC Regional Reliability~~Security~~ Coordinators

(a) The Regional Reliability~~Security~~ Coordinator has the final authority to direct operations before, during and after problems or disturbances that have regional impacts. The WSCC security monitoring plans include collaboration with sub-regional Regional Reliability~~Security~~ Coordinators and control area operators to determine actions for anticipated problems. If there is insufficient time, or mutual concurrence is not reached, the Regional Reliability~~Security~~ Coordinator is authorized to direct actions and the control area operators must comply.

(b) In the event of any situation occurring which is outside those problems already identified in the list of known problems, the Regional Reliability~~Security~~ Coordinator shall have the responsibility and authority to implement whatever measures are necessary to maintain system reliability. Those actions include but are not limited to; interchange curtailment, generation dispatch adjustment (real power, reactive power and voltage), transmission configuration adjustments, special protection activation, load curtailment and any other action deemed necessary to maintain system reliability.

(c) The Regional Reliability~~Security~~ Coordinator shall also have the responsibility and authority to take action in its sub-region for problems in another sub-region that it may help resolve. This must be accomplished at the request of and in coordination with the Regional Reliability~~Security~~ Coordinators of the other sub-regions.

**DP 7 REAL TIME OPERATIONAL ACTIVITIES –
THE HOUR PRIOR TO THE SETTLEMENT PERIOD**

DP 7.1 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) ~~(a)~~ verify that ~~each SC's Ancillary Services obligations~~ there are sufficient Ancillary Services ~~are~~ scheduled as needed to meet the ISO ~~required~~Ancillary Service requirements. The ISO will procure additional Ancillary Services if insufficient resources are scheduled;

(b) review the available Energy bids that will be used in the Real-Time Market;

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

(d) perform the Hourly Pre-Dispatch process in accordance with Section 31.4.2;

DP 7.2 Confirm Interchange Transaction Schedules (ITSs)

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

(a) adjust interchange transaction schedules (ITSs) as required under Existing Contracts in accordance with the procedures in the SBP and the SP 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.

DP 7.3 ~~Supplemental Energy Bids~~ [Not Used]

~~Supplemental Energy bids may be submitted to the ISO no later than forty-five (45) minutes prior to the beginning of the Settlement Period in accordance with the format and content requirements of the SBP. These Supplemental Energy bids cannot be withdrawn after forty-five (45) minutes prior to the beginning of the Settlement Period, except that a bid from a System Resource may specify that any portion of the bid that is not called prior to the beginning of the Settlement Period shall not be called after the beginning of the Settlement Period. The ISO may Dispatch the associated resource at any time during the Settlement Period.~~

DP 7.4 ~~Intra-Zonal Congestion Management~~ [Not Used]

~~In the hour prior to the beginning of the Settlement Period the ISO may adjust SCs' Final Schedules to alleviate Intra-Zonal Congestion. Except in those instances where the ISO calls Reliability Must-Run Units as provided in Section 5.2 of the ISO Tariff, the ISO will adjust resources in accordance with DP 8.4 and DP 8.5.~~

DP 7.5 Withdrawal of Supplemental ~~Real-Time~~ Energy Bids

Scheduling Coordinators may contact the ISO to withdraw Bids from System Resources (unless such bids are from Capacity Resources) at any time before they are Dispatched by the ISO for a particular Settlement Period~~Operating Hour~~, however, once these Bids are Dispatched by the ISO they cannot be withdrawn.

DP 8 REAL TIME OPERATIONAL ACTIVITIES – THE SETTLEMENT PERIOD

DP 8.1 Settlement Period

DP 8.1.1 Responsibility of the ISO in Real Time Dispatch

During real time Dispatch, the ISO will be responsible for dispatching Generating Units, System Units, ~~Curtailable Demands~~Dispatchable Load and ~~Interconnection schedules~~System Resources to meet real time imbalances between actual and scheduled Demand and Generation and to relieve Congestion, if necessary, to ensure System Reliability and to maintain Applicable Reliability Criteria.

~~DP 8.1.2 Utilization of BEEP~~DP 8.1.2 Utilization of Security Constrained Economic Dispatch

To achieve this, the ISO Control Center will utilize ~~the merit order stack of available resources prepared pursuant to the SP through BEEP~~a Security Constrained Economic Dispatch (“SCED”) program pursuant to Section 31.4.3.2.2.1 to determine the recommended Dispatch instructions.

DP 8.1.3 Exceptional Dispatches

In addition to those resources dispatched by the SCED the ISO may dispatch additional resources as needed to perform Ancillary Services testing, to address Overgeneration, Contingencies, Loop Flows, Nomogram violations, emergency conditions, or any other threats to System Reliability that cannot be addressed by SCED due to modeling limitations, insufficient or inaccurate data input in accordance to Section 31.4.3.2.5.

DP 8.2 Generating Units, Loads and Interconnection Schedules Dispatched for Congestion

If there is ~~Inter-Zonal or Intra-Zonal~~ Congestion in real time, the ISO will use ~~the merit order stack produced by BEEP~~recommended Dispatch ~~I~~instructions produced by the SCED to alleviate ~~Inter-Zonal~~ the Congestion as described in DP 8.3. The ISO will use any ~~Adjustment~~ unused Energy Bids ~~which~~ that have been carried forward from ~~the Day-Ahead or~~ the Hour-Ahead Market~~s~~ as described in ~~SBP 4~~Section 31.4.1.~~, to resolve Intra-Zonal Congestion as described in DP 8.4~~.

DP 8.3 ~~Inter-Zonal~~ Congestion Management

The ISO will utilize a full network model within the SCED that reflects all real-time network configurations and constraints as determined by the latest State Estimator solution as described in Section 31.4.3.2.1. SCED will be used to economically Dispatch Generating Units, Dispatchable Load, System Units and System Resources to effectively meet Imbalance Energy requirements and eliminate Price Overlap in real-time subject to network constraints that actually exist and to prevent network constraints from developing.

DP 8.3.1 ~~**Treatment by Zone**~~**[Not Used]**

~~If there is Inter-Zonal Congestion in real time, the ISO shall increase Generation and/or reduce Demand separately for each Zone.~~

DP 8.3.2 **[Not Used]**~~**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 from the merit order stack 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~~.

DP 8.3.3 **[Not Used]**~~**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 from the merit order stack the Generating Unit within the Zone with a non-zero capacity remaining to decrement which has the highest decremental bid price.~~

DP 8.4 ~~**Intra-Zonal Congestion**~~**[Not Used]**

~~Except as provided in Section 5.2 of the ISO Tariff, in the event of Intra-Zonal Congestion in real time, the ISO shall adjust Generating Units and Curtailable Demands (or Interconnection schedules of System Resources in the Control Areas) to alleviate the constraints, using available Adjustment Bids and Imbalance Energy bids based on their effectiveness and in merit order.~~

DP 8.5 **Additional Congestion Relief**

If ISO is unable to resolve Congestion utilizing submitted Energy Bids, the ISO will insert default E~~e~~nergy B~~b~~ids for those resources capable of responding to real-time Dispatch instructions into the SCED to manage the Congestion as described in Section 31.4.3.2.3.2. ~~In the event that there are insufficient resources which provide financial bids to mitigate Inter-Zonal and Intra-Zonal Congestion, Final Schedules which do not rely on Existing Contracts will be adjusted in real time by allocating transmission capacity on a pro rata basis.~~ Final Schedules which rely on Existing Contracts will be adjusted in real time by allocating transmission capacity in accordance with the operating instructions submitted under SBP 3.3. With respect to facilities financed with Local Furnishing Bonds the ISO shall adjust Final Schedules in real time in a fashion consistent with Section 2.1.3 and 7.1.6.3 of the ISO Tariff, Appendix B of the TCA, and Operating Procedures governing the use of such facilities.

DP 8.6 **Real Time Dispatch Application**

DP 8.6.1 **Real Time Dispatch**

During real time, the ISO shall dispatch Generating Units, System Units, ~~Curtailable Demands~~Dispatchable Load and ~~Interconnection~~ System Resources ~~schedules~~ to meet imbalances between actual and scheduled Demand and Generation.

In addition, the ISO shall procure ~~may need to purchase~~ additional Ancillary Services as set forth in Section 31.4.4 if Ancillary Services procured~~arranged~~ in advance are used to provide Imbalance~~balancing~~ Energy, and such depletion needs to be recovered to meet System Reliability and contingency requirements.

DP 8.6.2 **Utilization of the** ~~**Merit Order Stack**~~**SCED**

The ISO will use the ~~merit order stack~~recommended Dispatch instructions as produced by ~~BEEP~~the SCED program~~, consisting of all the Supplemental Energy and Ancillary Services Energy bids as described in the SP~~ 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 Dispatch Operating Point ~~Preferred Operating Point~~ of their regulating ranges;

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

(e) procuring additional real-time Voltage Support required from resources beyond the~~ir~~ power factor range~~s~~ set forth in Section 2.5.3.4~~ in real time~~.~~; and~~

(f) [Not Used]~~managing Intra-Zonal Congestion in real time after use of available Adjustment Bids.~~

DP 8.6.3 Basis for Real Time Dispatch

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

(a) the ISO shall dispatch Generating Units and System Resources~~dispatchable Interconnection schedules~~ providing Regulation service to meet WSCC and NERC Area Control Error (ACE) performance criteria;

(b) in each ~~BEEP~~ Dispatch Interval, following the loss of a resource and once ACE has returned to zero, the ISO shall determine if the Regulation Generating Units and ~~Interconnection schedules~~System Resources are operating at a point away from their Set Point. The ISO shall then adjust the output of Generating Units, System Units, ~~Curtailable Demands~~Dispatchable Load, and ~~Interconnection schedules~~System Resources (either providing Spinning Reserve, Non-Spinning Reserve, ~~Replacement Reserve, or Supplemental~~ or Real-Time Imbalance Energy) to return the Regulation Generating Units and ~~Interconnection schedules~~System Resources to their Set Points to restore their full regulating margin;

(c) in each ~~BEEP~~ Dispatch Interval, the ISO shall dispatch Generating Units, System Units, ~~Curtailable Demands~~Dispatchable Load and ~~dispatchable Interconnection schedules~~System Resources to meet its ~~balancing~~ Imbalance Energy requirements and eliminate any Price Overlap between decremental and incremental Energy Bids at least cost~~, thereby, dispatching the relevant resources in real time for economic trades either between SCs or within a SC's portfolio~~;

(d) [Not Used]~~the ISO shall select the Generating Units, Curtailable Demands and dispatchable Interconnection schedules to be dispatched to meet its balancing Energy requirements based on the merit order stack of Energy bid prices produced by BEEP;~~

(e) the ISO shall not discriminate between Generating Units, System Units, ~~Curtailable Demands~~Dispatchable Load and ~~dispatchable Interconnection schedules~~System Resources other than based on Energy ~~price~~bids, and the effectiveness (location~~ and ramp rate~~) of the resource concerned to respond to the fluctuation in Demand or Generation, subject to network and ramp rate constraints;

(f) Generating Units, System Units, Dispatchable Load or ~~Interconnection schedules~~ System Resources shall be dispatched during the Settlement Period only until the next variation in Generation or Demand or the end of the Settlement

Period, whichever is sooner. In dispatching such resources, the ISO is not making any commitment beyond the Settlement Period, as to the duration of their operation, nor the level of their output or Demand;

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

(h) [Not Used]~~Within BEEP, once a decremental bid has been used by the ISO, it will then be included in the incremental part of the database with its incremental bid equal to its decremental price~~

~~bid. Once an incremental bid has been used by the ISO it will then be included in the decremental part of the database with a decremental bid equal to its incremental price;~~

(i) The ~~bid~~ ramp rate as identified in the ISO Master File of a resource will be considered by the ~~BEEP~~SCED ~~software~~program in determining the amount of Instructed Imbalance Energy ~~by~~ Dispatched and thereby deemed delivered during the ~~BEEP~~ Dispatch Interval, and such consideration may result in Instructed Imbalance Energy in ~~BEEP~~ Dispatch Intervals subsequent to the ~~BEEP~~ Dispatch Interval to which the Dispatch Instruction applies;

(j) ~~Between 10 minutes and 45 minutes prior to the beginning of the operating hour~~The Hourly Pre-Dispatch ~~will take place~~ ~~will~~shall take place no later than 30 minutes prior to the Settlement Period~~Operating Hour~~. The ISO shall Dispatch resources at least cost to supply Imbalance Energy or Dispatch demand on an hourly basis to meet some of the Settlement Period~~Operating Hour~~'s forecasted Imbalance Energy requirement plus Ramping Energy requirements for the transition into the Settlement Period~~Operating Hour~~'s scheduled G~~g~~eneration and interchange. ~~t~~The ISO shall ~~estimate the interchange bids that need to be~~determine the ~~dispatched~~ Hourly Pre-Dispatch Energy prior to the beginning of the Settlement Period~~operating hour~~ to: i~~a~~) ensure resources that require advance notice are provided such notice prior to requiring their energy, ii~~b~~) instruct ~~interchange bids~~System Resources far enough in advance to allow the interchange bid to be arranged with external control areas and iii~~c~~) allow resources that have been dispatched in the previous Settlement Period~~operating Operating H~~h~~our~~ and are determined to be economic in the upcoming ~~operating~~ Settlement Period~~Operating hour Hour~~ to maintain their instructed level. The Hourly Pre-Dispatch optimization methodology is described in Appendix A to this Protocol~~D~~. ~~During this pre-dispatch evaluation process, any Price Overlap will be economically dispatched. The pre-dispatch evaluation process will consider the forecast Imbalance Energy requirements of the first interval of the upcoming operating hour to determine the amount of energy from dispatchable resources. This pre-dispatch process will also consider the forecast imbalance energy requirement for the each interval of the upcoming operating hour to determine the amount of Energy to be dispatched for hourly resources such as interchange bids .~~

(k) The ISO may notify resources to be Dispatched within the Settlement Period in advance of the Settlement Period to i) allow those resources previously Dispatched to maintain their instructed level, or ii) provide sufficient notice to resources providing Supplemental Energy with start-up times longer than ten minutes.

~~(k) The ISO will pre-dispatch Energy Bids from Interconnection schedules,System Resources subject to hourly pre-dispatch as indicated in Section 4.2 and SBP 6.1.3, prior to the beginning of each hour consistent with applicable WSCC interchange scheduling practices, assuring that any Price Overlap between such decremental and incremental Energy Bids will be eliminated. Instructed Imbalance Energy from hourly pre-dispatched bids will be paid or charged the simple average of BEEP Interval Ex Post Prices for the hour. To the extent the settlement of the of the pre-dispatched interchange does not allow the interchange bid to recover its bid, an additional settlement wil be made to compensate the interchange for unrecovered costs for the hour in which it was dispatched.~~

DP 8.7 Ancillary Services Requirements

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

DP 8.7.1 Regulation

(a) Regulation provided from Generating Units or System Resources must meet the standards specified in the ASRP;

(b) the ISO will dispatch Regulation as determined by ISO EMS AGC program to respond to Area Control Error (ACE) on a continual basis to maintain system frequency and net scheduled control area interchange. ~~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 DP 8.7.4);

DP 8.7.2 Operating Reserve

(a) Spinning Reserve:

(i) Spinning Reserve provided from Generating Units and Interconnection schedules must meet the standards specified in the ASRP;

(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 Imbalance ~~balancing~~ Energy to return Regulation Generating Units to their Set Points and restore full Regulation margin; and

(iv) the ISO will dispatch Spinning Reserve as determined by SCED~~in merit order of Energy bid prices as determined by BEEP~~;

(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 the ASRP;

(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 SCED~~BEEP~~; 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 Imbalance~~balancing~~ Energy;

DP 8.7.3 [Not Used]~~Replacement Reserve~~

~~(a) Replacement Reserve provided from Generating Units, Curtailable Demands and Interconnection schedules must meet the standards specified in the ASRP;~~

~~(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 BEEP;~~

DP 8.7.4 Replacement of Operating Reserve

(a) [Not Used]~~in the event of an unforecasted increase in system Demand or a shortfall in Generation output, the ISO shall utilize Replacement Reserve to restore Operating Reserve~~;

(b) if ~~pre-arranged~~ Operating Reserve is used to meet Imbalance~~balancing~~ Energy requirements, the ISO may replace such Operating Reserve by dispatching ~~of~~ additional ~~balancing~~ Imbalance Energy available from Supplemental Energy bids;

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

(d) where the ISO elects to rely upon Supplemental Energy bids, the ISO shall select the resources ~~with the lowest incremental Energy bid price as established by BEEP~~at least cost and to eliminate any Price Overlap between incremental and decremental Supplemental Energy Bids subject to network constraints~~; and~~

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

DP 8.7.5 **Voltage Support**

(a) Voltage Support provided from Generating Units shall meet the standards specified in the ASRP;

(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 2.5.3.4 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 Section 2.5.18 of the ISO Tariff;

(d) If Voltage Support is required in addition to that provided pursuant to DP 8.7.5 (b) and (c), the ISO will reduce output of Participating Generators certified in accordance with the ASRP ~~based on the merit order stack~~as determined by ~~BEEP~~SCED. 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.

DP 8.7.6 **Black Start**

(a) Black Start shall meet the standards specified for Black Start in the ASRP; and

(b) the ISO will dispatch Black Start as required in accordance with the applicable Black Start Agreement.

DP 8.8 **Real Time Management of Overgeneration Conditions**

In the event that Overgeneration conditions occur during real time, the ISO will direct the SCs to take the steps described in Section 2.3.4 of the ISO Tariff and SCs shall implement ISO directions without delay.

DP 9 **DISPATCH INSTRUCTIONS**

DP 9.1 **ISO Dispatch Authority**

DP 9.1.1 **Range of ISO Authority**

The ISO has full authority to:

(a) direct the physical operation of the ISO Controlled Grid, including (without limitation) circuit breakers, switches, voltage control equipment, protective relays, metering and Load Shedding equipment;

(b) commit Reliability Must-Run Generation, except that the ISO shall only commit Reliability Must-Run Generation for Ancillary Services capacity according to Section 5.2 of the Tariff;

(c) order a change in operating status of voltage control equipment;

(d) take required action to prevent against uncontrolled losses of load or Generation;

(e) control the output of Generating Units and Interconnection schedules scheduled to provide Ancillary Services or offering Supplemental Energy;

(f) dispatch Dispatchable Load~~Curtailable Demand~~ which has been scheduled to provide Non-Spinning Reserve~~ or Replacement Reserve~~; and

(g) require the operation of resources which are at the ISO's disposal in a System Emergency, as described in DP 10.

DP 9.1.2 Exercise of the ISO's Authority

The ISO will exercise its authority under DP 9.1.1 by issuing Dispatch Instructions to the relevant Participants using the relevant communications method described in DP 4.

DP 9.2 Participant Responsibilities

DP 9.2.1 Compliance with Dispatch Instructions

All Participants within the ISO Control Area and all System Resources shall comply fully and promptly with the ISO's Dispatch Instructions unless such operation would impair public health or safety. In this regard, ~~Real-Time~~ Dispatch Instructions for Energy by Generating Units, System Resources, System Units and Dispatchable Load, are deemed to be operating orders pursuant to Section 2.3.1.2.1. As such these Dispatch Instructions are binding obligations and a resource so Dispatched cannot be made unavailable or otherwise fail to respond to ISO operating orders except for conditions beyond the control of the resource owner. Shedding Load for a System Emergency does not constitute impairment to public health or safety.

DP 9.2.2 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 SC immediately. The relevant SC shall notify the ISO of the problem immediately.

DP 9.3 Dispatch Instructions for Generating Units and ~~Curtailable Demand~~Dispatchable Load

The ISO may issue Dispatch Instructions covering:

(a) Ancillary Services;

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

(i) managing Congestion~~ Management~~; or

(ii) replacing~~ement of~~ an Ancillary Service;

(c) agency operation of Generating Units, ~~Curtailable Demands~~Dispatchable Load or ~~Interconnection schedules~~System Resources, 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 the ASRP.

DP 9.4 Response Required by Generators to ISO Dispatch Instructions

DP 9.4.1 Action Required by Generators

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 and ASRP;

(c) meet the ramp rates required by ASRP for the Ancillary Service concerned;

(d) respond to Dispatch Instructions for Ancillary Services within the time periods required by ASRP except in a System Emergency, when DP 10 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 shut down of a Generating Unit, within the time frame stated in the Instruction.

DP 9.4.2 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 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 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 instructions during a System Emergency without penalty for failure to do so.

DP 9.5 Failure to Comply with Dispatch Instructions

DP 9.5.1 Obligation to Comply

All entities 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 to the ISO's Dispatch Instructions in accordance with their terms. If a dispatched Generating Unit, System Unit, Dispatchable Load~~Curtailable Demand~~ or System Resource~~Interconnection schedule~~ fails to respond to a Dispatch Instruction in accordance with its terms, that entity~~e Generating Unit, Curtailable Demand or Interconnection schedule~~:

(a) shall be declared and labeled as non-conforming to the Dispatch Instruction;

(b) cannot ~~be eligible to~~ set the Dispatch Interval LMP~~Hourly Ex Post Price~~.

DP 9.5.2 Sanctions

The ISO will develop additional mechanisms to deter Generating Units and Loads in other Control Areas from failing to respond at a particular time or adequately respond over a particular period of time to a Dispatch Instruction or failing to perform according to Dispatch Instructions, for example, reduction in payments to SCs or suspension of the SC's Ancillary Services certificate for the Generating Unit, Dispatchable Load~~Curtailable Demand~~ or System Resource concerned.

DP 10 EMERGENCY OPERATIONS

DP 10.1 Notifications by ISO

The ISO will provide the following notifications to Participants to communicate unusual system conditions or emergencies.

DP 10.1.1 System alert

ISO will give a system alert notice when the operating requirements of the ISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation or loss of transmission capacity that has curtailed imports into the ISO Control Area, or if the Hour-Ahead Market is short on scheduled Energy and Ancillary Services for the ISO Control Area.

DP 10.1.2 System warning

The ISO will give a system warning notice when the operating requirements for the ISO Controlled Grid are not being met in the Hour-Ahead Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve, ~~Replacement Reserve~~ and Supplemental Energy available to the ISO is not acceptable for the Applicable Reliability Criteria. This system warning notice will notify Participants that the ISO will, acting in accordance with Good Utility Practice, take such steps as it considers necessary to ensure compliance with Applicable Reliability Criteria, including the negotiation of Generation through processes other than competitive bids.

DP 10.1.3 System Emergency

When, in the judgement of the ISO, the System Reliability of the ISO Controlled Grid is in danger of instability, voltage collapse or under-frequency caused by transmission or Generation trouble in the ISO Control Area, or events outside of the ISO Control Area that could result in a cascade of events throughout the WSCC grid, the ISO will declare a System Emergency. This declaration may include a notice to suspend the Day-Ahead, Hour-Ahead and Real Time Markets, authorize full use of Black Start Generation, initiate full control of manual Load Shedding, authorize the curtailment of Dispatchable Load ~~Curtailable Demand~~ (even though not scheduled as an Ancillary Service). The ISO will reduce the System Emergency declaration to a lower alert status when it is satisfied, after conferring with Security

Coordinators within the WSCC that the major contributing factors have been corrected, all involuntarily interrupted Demand is back in service (except interrupted ~~Curtailable Demand~~Dispatchable Load selected as an Ancillary Service). This reduction in alert status will reinstate the competitive markets if they have been suspended.

DP 10.2 Management of System Emergencies

DP 10.2.1 Declaration of System Emergencies

The ISO shall, when it determines that a System Emergency exists, declare the existence of such System Emergency. A declaration of System Emergency by the ISO shall be binding on all Participants until the ISO announces that the System Emergency no longer exists.

DP 10.2.2 Emergency Procedures

In the event of a System Emergency, the ISO shall:

(a) take action as it considers necessary to preserve or restore stable operation of the ISO Controlled Grid;

(b) act in accordance with Good Utility Practice to preserve or restore reliable, safe and efficient service as quickly as reasonably practicable;

(c) keep adjacent Control Area Operators informed as to the nature and extent of the System Emergency in accordance with WSCC procedures; and

(d) where practicable, keep the Participants within the ISO Control Area informed.

DP 10.2.3 [Not Used]~~Intervention in Market Operations~~

~~(a) The ISO may intervene in the operation of the Day-Ahead, Hour-Ahead or Real Time Markets and set the Administrative Price if the ISO determines that such intervention is necessary in order to contain or correct the System Emergency.~~

~~(b) The ISO will not intervene in the operation of the Day-Ahead Market unless there has been a total or major collapse of the ISO Controlled Grid and the ISO is in the process of restoring it.~~

~~(c) Before any such intervention, the ISO must (in the following order):~~

~~(i) Dispatch all scheduled Generation and all other Generation offered or available to it, regardless of price (including all Supplemental Energy bids, and Ancillary Services);~~

~~(ii) Dispatch all interruptible Loads made available by UDCs to the ISO in accordance with the UDC Operating Agreements;~~

~~(iii) Dispatch or curtail all price-responsive Curtailable Demand that has been bid into any of the markets and exercise its rights under all Load curtailment contracts available to it; and~~

~~(iv) exercise Load Shedding to curtail Demand on an involuntary basis to the extent that the ISO considers necessary.~~

~~(d) The Administrative Price in relation to each of the markets for Imbalance Energy, Ancillary Services and Congestion Management~~EnergyEnergy ~~shall be set at the applicable Market Clearing Price or appropriate charge, as the case may be, in the Settlement Period immediately preceding the Settlement Period in which the intervention took place. (e) The intervention will cease as soon as the ISO has restored all Demand that was curtailed on an involuntary basis as specified in (c).~~

DP 10.2.4 Emergency Guidelines

The ISO shall issue procedures for all Participants to follow during a System Emergency. These guidelines shall be consistent with the specific obligations of SCs and Participants referred to in DP 10.2.8, and DP 10.4

DP 10.2.5 Implementation of Dispatch Instructions

All Participants shall respond to ISO Dispatch Instructions with an immediate response during System Emergencies.

DP 10.2.6 Periodic Tests of Emergency Procedures

The ISO shall develop and administer periodic unannounced tests of System Emergency procedures. The purpose of such tests will be to ensure that the Participants are capable of responding to actual System Emergencies.

DP 10.2.7 Prioritized Schedule for Shedding and Restoring Load

The ISO shall, in consultation with Participants, develop a prioritized schedule for Load Shedding if a System Emergency requires such action. Such a schedule will include a prioritization of restoring Load if multiple Participants are affected.

DP 10.2.8 Obligations of Participating Generators Relating to System Emergencies

All Generating Units are subject to control by the ISO during a System Emergency. The ISO shall have the authority to:

(a) instruct a Participating Generator to shut down any of its Generating Units which the Participating Generator does not require, or start any of its Generating Units that can be started in time to assist with the System Emergency;

(b) instruct a Participating Generator to increase or curtail the output of any of its Generating Units; and

(c) instruct the alteration of scheduled deliveries of Energy and/or Ancillary Services into or out of the ISO Controlled Grid,

if such an instruction is reasonably necessary to prevent an imminent System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency, and provided that the ISO has, where reasonably practicable, utilized Ancillary Services which it has the contractual right to instruct and which are capable of contributing to or containing or correcting actual, imminent or threatened System Emergencies prior to issuing such instructions.

DP 10.3 External Support/Assistance

If, on a real time basis, the ISO is unable to comply with the Applicable Reliability Criteria, the ISO shall take such steps as it considers necessary, to ensure compliance, including the negotiation of contracts for Ancillary Services through processes other than competitive solicitations. If the ISO is unable to obtain such resources from within the ISO Controlled Grid, the ISO may solicit Ancillary Services from other Control Areas on a real time basis.

DP 10.4 UDC Emergency Procedures

In the event of a System Emergency, each UDC shall comply with all directions from the ISO concerning the management and alleviation of the System Emergency and shall comply with all procedures outlined in this Protocol.

DP 10.4.1 Use of UDC's Existing Load Curtailment Programs.

(a) UDC Electrical Emergency Plans

The ISO shall have the authority to implement a UDC’s Electrical Emergency Plan in consultation with the UDC, when Energy reserve margins are forecast to be at the levels specified in the existing plan.

(b) UDC Under-Frequency Load Shedding Programs (UFLS):

The ISO shall:

(i) with the UDC, review that UDC’s UFLS program periodically to ensure compliance with Applicable Reliability Criteria;

(ii) perform periodic audits of each UDC’s UFLS to verify that the system is properly configured for each UDC; and

(iii) use reasonable endeavors to ensure that the total ISO UFLS is coordinated among the UDCs so that no UDC bears a disproportionate share of the total ISO UFLS program.

(c) UDC Disconnect Load

The ISO shall have the authority to direct a UDC to disconnect Load from the ISO Controlled Grid if necessary to avoid an anticipated System Emergency or to regain Operational Control over the ISO Controlled Grid during an actual System Emergency.

(d) UDC Load Curtailment Programs

As an additional resource for maintaining reliability and managing System Emergencies, the ISO may notify UDCs when the conditions exist which require the UDCs to implement their Load curtailment programs. The UDCs will exercise their best efforts, including seeking any necessary regulatory approvals, to enable the ISO to rely on their curtailment rights at specified levels of Operating Reserve.

DP 10.4.2 Load Curtailment

A SC may specify that Load will be reduced at specified Locational Marginal Prices ~~Market Clearing Prices~~ or offer the right to exercise Load curtailment to the ISO as an Ancillary Service or utilize Load curtailment itself (by way of self provision of Ancillary Services) as Non-Spinning Reserve~~ or Replacement Reserve~~. The ISO, at its discretion, may require direct control over such ~~Curtailable Demand~~Dispatchable Load to assume response capability for managing System Emergencies. The ISO may establish standards for automatic communication of curtailment instructions to implement Load curtailment as a condition for accepting any offered Load curtailment as an Ancillary Service.

DP 11 ALGORITHMS TO BE USED

The ISO shall develop dispatch algorithms for use by the ISO for dispatching Generating Units and ~~Curtailable Demands~~Dispatchable Load in accordance with the ISO Tariff.

DP 12 INFORMATION MANAGEMENT

The ISO shall provide all Participants with non-discriminatory access to information concerning the status of the ISO Controlled Grid by posting such information on the OASIS~~WEnet~~, or other similar computer communications device, or by telephone or facsimile in the event of computer systems failure.

DP 13 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

APPENDIX A. HOURLY PRE-DISPATCH

A.1 Introduction

The ISO will conduct an Hourly Pre-Dispatch Process for eligible resources approximately 30 minutes prior to each hour. Hourly Imbalance Energy bids will be selected at least cost to satisfy a portion of the hour's Imbalance Energy requirement. The selected bids will be pre-dispatched for the entire hour. The associated positive Instructed Energy will be paid the higher of its bid or the simple average of the relevant six 10-minute LMPs within the hour. The selection of the Hourly Imbalance Energy bids will be determined by an optimization method so that the overall cost of Imbalance Energy (procured hourly and at each 10-minute Dispatch Interval within the hour) is minimized. The ISO refers to this optimization method as the "Hourly Pre-Dispatch Application (HPDA)" in contrast with the Security Economic Dispatch (SCED) that takes place every 10 minutes within the hour.

A.2 Functional Description

HPDA will evaluate unused Hour-Ahead Energy bids from eligible resources for either Hourly Pre-Dispatch or interval Dispatch to minimize the overall cost of Imbalance Energy procurement required to satisfy projected Imbalance Energy requirements throughout the hour. The Imbalance Energy requirements at each Dispatch Interval will be estimated based on the Final Hour-Ahead Schedules for generation, imports, and exports, their respective scheduling ramps (as described in Section 31.4.2.3), and a forecasted load profile. The load profile will be derived by 10-minute forecasts, or by interpolating hourly forecasts, as shown in Figure 1. Figure 1 assumes the scheduling ramp is a 20-minute linear ramp that begins ten minutes before the start of the hour and ends ten minutes after the beginning hour. To calculate the overall cost of Imbalance Energy procurement, HPDA will produce the optimal estimated Dispatch and the Dispatch Interval LMPs in the next hour to satisfy the estimated Imbalance Energy requirement reduced by the amount of Imbalance Energy that will be procured by the Hourly Pre-Dispatch process. Therefore, the HPDA will use a simplified version of the SCED. Since the SCED solution in a given Dispatch Interval depends on the SCED solution of the previous interval, the evaluation must be sequential. Furthermore, due to the discontinuity and the composite nature of the objective function, the optimization method is in a master-slave sub-problem formulation. The master sub-problem is a linear search for the optimal value of the Hourly Imbalance Energy procurement that minimizes the overall cost. The slave sub-problems are the 10-minute SCEDs that minimize the cost in each interval sequentially, given an Hourly Imbalance Energy procurement. Figure 2 illustrates the HPDA methodology.

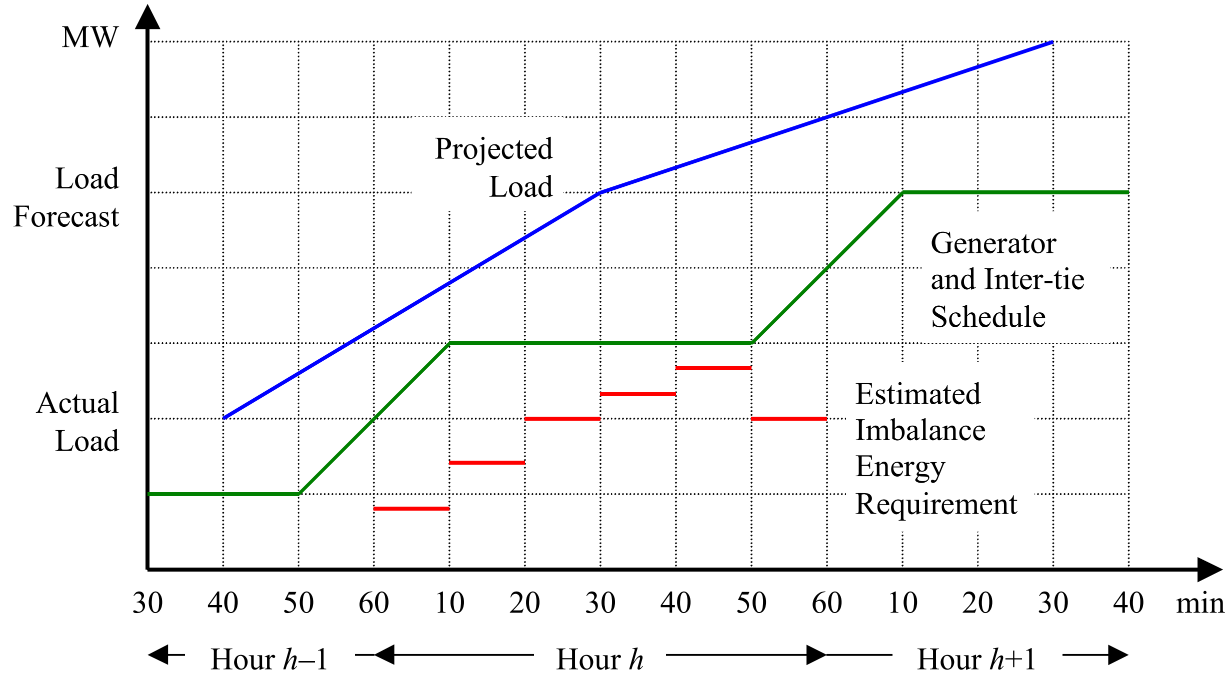

Figure 1. *HPDA Imbalance Energy requirement estimation*

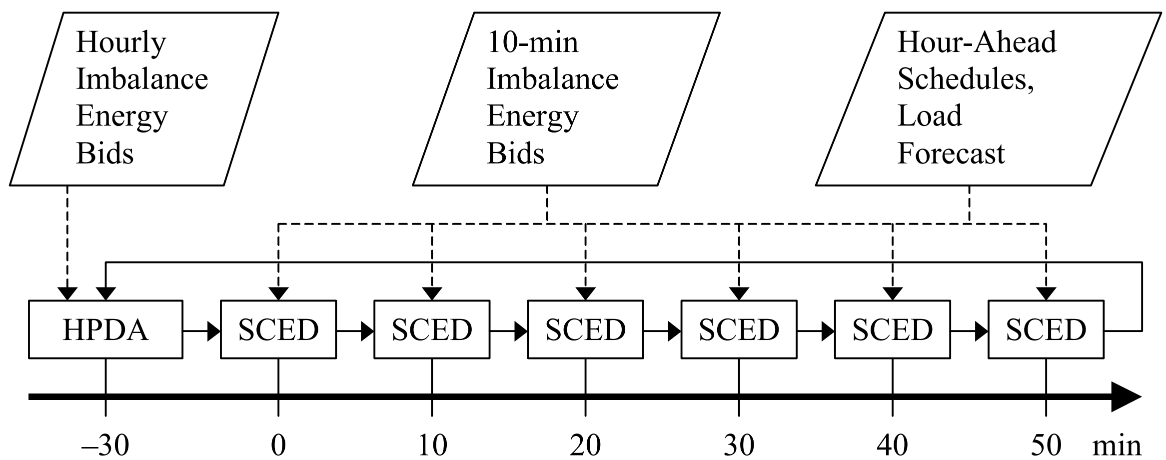

Figure 2. *HPDA master-slave sub-problem formulation*

The HPDA sub-problem will be a linear search algorithm on the Hourly Imbalance Energy procurement that minimizes the overall cost. The hourly cost component will be calculated from the Dispatch Interval LMPs determined by the SCED solutions, one for each Dispatch Interval during the hour. Each interval cost component would be the product of the expected Instructed Imbalance Energy in that Dispatch Interval and the respective LMP.

ISO MARKET MONITORING & INFORMATION PROTOCOL

APPENDIX A

ISO Market Monitoring Plan

Market Mitigation Measures

1 PURPOSE AND OBJECTIVES

1.1 These ISO market power mitigation measures ("Mitigation Measures") are intended to provide the means for the ISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the ISO ~~Real Time~~ Markets and Residual Unit Commitment Processes 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 specified below.

1.2 In addition, the ISO shall monitor the markets it administers for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the ISO. If the ISO 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 the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the ISO's justification for imposing that mitigation measure.

1.2 CONDUCT WARRANTING MITIGATION

2.1 Definitions

The following definitions are applicable to this Appendix A:

"Economic Market Clearing Prices" are the market clearing prices for a particular resource at the location of that particular resource at the time the resource was either Scheduled or was Dispatched by the ISO. Economic Market Clearing Prices may originate from the Day-A~~a~~head Energy M~~m~~arket, the Hour-ahead Energy M~~m~~arket~~ (when these markets are in place)~~, or ISO Real-time Imbalance Energy market. The Economic Market Clearing Price for the ISO Real Time Imbalance Energy Market shall be the Dispatch Interval Locational Marginal Price~~BEEP Interval Ex Post Price~~, unless the resource cannot change output level within the hour (i.e., the resource is not amenable to intra-hour real-time dispatch instructions), or it is a System Resource. Economic Market Clearing Prices for the ISO Real Time Imbalance Energy Market for resources that cannot change output level within one Dispatch~~BEEP~~ Interval and System Resources shall be the simple average of the Dispatch Interval Locational Marginal Prices~~six BEEP Interval Ex Post Prices~~ for each hour.

"Electric Facility" shall mean an electric resource, including a Generating Unit, System Unit, Participating Load or a System Resource.

2.2 Conduct Subject to Mitigation

Mitigation Measures may be applied: (i) to the bidding, scheduling, or operation of an "Electric Facility"; or (ii) as specified in section 2.4 below.

2.3 Conditions for the Imposition of Mitigation Measures

2.3.1 In general, the ISO 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 three categories of conduct specified in Section 2.4 below.

2.4 Categories of Conduct that May Warrant Mitigation

2.4.1 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 an ISO Real Time Market or Residual Unit Commitment process if exercised from a position of market power. Accordingly, the ISO shall monitor the ISO 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 an ISO 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 bids 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 bids called upon by the ISO (unless the ISO is informed in accordance with established procedures that the relevant resource for which the bid is submitted has undergone a forced outage or derate), or (iv) operating a Generating Unit in real-time to produce an output level that is less than the ISO's Dispatch I~~i~~nstruction.

(2) Economic withholding of an Electric Facility, that is, submitting bids 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 bids will set a market clearing price.

(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 network~~transmission~~ constraint.

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 an ISO 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.

2.4.3 Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than an ISO Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

2.4.4 The ISO shall monitor ISO 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 an ISO Market or other payments. The ISO 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 Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the FERC as may be appropriate.

3 CRITERIA FOR IMPOSING MITIGATION MEASURES

3.1 Identification of Conduct Inconsistent with Competition

Conduct that may potentially warrant the imposition of a mitigation measure includes the categories described in Section 2.4 above. The thresholds listed in section 3.1.1 below shall be used to identify substantial departures from competitive conduct indicative of an absence of workable competition.

3.1.1 Conduct Thresholds for Identifying Economic Withholding

The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of the bid from a resource and shall be determined with respect to a reference level determined as specified in Section 3.1.2:

Energy Bids: a 100 percent increase or $50/MWh increase in the bid, whichever is lower.

3.1.1.1 Reference Levels

(a) For purposes of establishing reference levels, bid segments shall be ~~defines~~ defined as follows:

1. the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (Pmin) and maximum (Pmax) operating point.
2. for Energy bids submitted over the intertie Scheduling Points (import bids), 10 bid segments shall be established for each

Scheduling Coordinator at each Scheduling Point based on historical volumes over the preceding 12 months.

A reference level for each bid segment shall be calculated for peak and off-peak periods on the basis of the following methods, listed in the following order of preference subject to the existence of sufficient data, where sufficient data means at least one data point per time period (peak or off-peak) for the bid segment. Peak periods shall be the periods Monday through Saturday from Hour Ending 0700 through Hour Ending 2200, excluding holidays. Off-Peak periods are all other hours.

1. The lower of the mean or the median of a resource's accepted bids in ~~competitive periods~~hours, where the Day-Ahead ISO Demand Forecast is less then or equal to 40,000 MW and the unit was Dispatched or Scheduled at least cost, over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices using the monthly proxy figure for natural gas prices posted on the ISO Home Page;
2. If the resource is a gas-fired unit that does not have significant energy limitations, the unit's default energy bid as set forth in Section 5.12 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh).

3. For non gas-fired units and gas-fired units that have significant energy limitations, a level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Participant has provided sufficient data on a unit's energy limitations and operating costs (opportunity cost for energy limited resources) in accordance with specifications provided by the ISO.

4. The mean of the Economic Market Clearing Prices for the units' relevant location (zone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours, where the Day-Ahead ISO Demand Forecast is less then or equal to 40,000 MW and ~~that~~ the unit was D~~d~~ispatched or S~~s~~cheduled at least cost, over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices; or

5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has

not been successful, the ISO shall determine a reference level on the basis of:

i. the ISO's estimated costs of an Electric Facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or

ii. an appropriate average of competitive bids of one or more similar Electric Facilities.

(b) The reference levels ($/MWh bid price) for the different bid segments of each resource (or import bid curve of a Scheduling Coordinator at a Scheduling Point) shall be made monotonically non-decreasing by the ISO by proceeding from the lowest MW bid segment moving through each higher MW bid segment. The reference level of each succeeding bid segment shall be the higher of the reference level of the preceding bid segment or the reference level determined according to paragraph (~~b~~a) above.

3.2 Material Price Effects

3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Market, Mitigation Measures for economic withholding shall not be imposed unless conduct identified as specified above causes or contributes to a material change in one or more of the ISO market-clearing prices (MCPs). Initially, the thresholds to be used by the ISO to determine a material price effect shall be an increase of 100 percent or $50 per MWh, whichever is lower, in the MCP at any location (zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

3.2.2 Price Impact Analysis

The ISO shall determine the effect on prices of questioned conduct through automated computer modeling and analytical methods. An Automatic Mitigation Procedure (AMP) shall identify bids that have exceeded the conduct thresholds and shall compute the change in MCPs as a result of simultaneously setting all such bids to their Reference Levels. If a change in the MCP exceeds the Impact threshold stated in Section 3.2.1, those bids would be kept mitigated at their default bid levels as specified in Section 4.2.2 below.

3.2.3 Section 205 Filings

In addition, the ISO shall make a filing under Section 205 of the Federal Power Act with the Commission seeking authorization to apply an appropriate mitigation measure to conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in section 3.1.1 above, unless the ISO determines, from information provided by the Market Participant or Parties that would be subject to mitigation or other information available to the ISO that the conduct is attributable to legitimate competitive market forces or incentives. The following are examples of conduct that are deemed to depart significantly from the conduct that would be expected under competitive market conditions:

(1) bids that vary with unit output in a way that is unrelated to the known performance characteristics of the unit, or

(2) bids that vary over time in a manner that appears unrelated to the change in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis.

The conducts listed above are intended to be examples rather than a comprehensive list.

3.3 Consultation with a Market Participant

If a Market Participant anticipates submitting bids in an ISO market administered by the ISO that will exceed the thresholds specified in Section 3.1 above for identifying conduct inconsistent with competition, the Market Participant may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Participant's bids. If a Market Participant's explanation of the reasons for its bidding indicates to the satisfaction of the ISO, that the questioned conduct is consistent with competitive behavior, no further action will be taken. Upon request, the ISO shall also consult with a Market Participant with respect to the information and analysis used to determine reference levels under Section 3.1.2 for that Market Participant.

4 MITIGATION MEASURES

4.1 Purpose

If conduct is detected that meets the criteria specified in Section 3, the appropriate mitigation measures described in this Section 4 shall be applied by the ISO. The conduct specified in Section 3.1.1 shall be remedied by the prospective application of a default bid measure as described in Section 4.2 for the specific hour that they violate the price and market impact thresholds.

4.2 Sanctions for Economic Withholding

4.2.1 Default Bid

A default bid shall be designed to cause a Market Participant to bid as if it faced workable competition during a period when: (i) the Market Participant does not face workable competition and (ii) has responded to such condition by engaging in the economic withholding of an Electric Facility. In designing and implementing default bids, the ISO shall seek to avoid causing an Electric Facility to bid below its marginal cost.

4.2.2 Implementation

(a) If the criteria contained in Section 3 are met, the ISO may substitute a default bid for a bid submitted for an Electric Facility. The default bid shall establish a maximum value for one or more components of the submitted bid, equal to a reference level for that component determined as specified in Section 3.1.1.

(b) The Mitigation Measures will be applied to 1) the Residual Unit Commitment Processes based on the projected Real-time LMPs~~MCPs~~ that are computed during ~~this~~ these processes; 2) all bids submitted to the Real Time Imbalance Energy Market during the pre-dispatch process~~-~~ prior to the Real Time Imbalance Energy Market based on the projected Real-time LMPs~~MCPs~~ that are computed during this process; and 3) to the ISO Day-Ahead and ~~the~~ Hour-ahead E~~e~~nergy Markets.~~markets when these markets are made operational~~.

(c) The bids that are mitigated in the Residual Unit Commitment Processes shall be reinstated to their original values and retested for both conduct and impact thresholds in the real-time pre-dispatch process. If the pre-dispatch market impact threshold is not violated, the bids shall be included in the real-time supply stack at their original (unmitigated) prices.

(d) An Electric Facility subject to a default bid shall be paid the LMP~~MCP~~ applicable to the output from the facility. Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the LMP~~MCP~~ applicable to that facility. With regard to imports into the ISO Control Area, importers subject to a default bid in the real-time market will be paid the higher of the ~~MCP~~ simple average of the Dispatch Interval Locational Marginal Prices for each hour or their default bid price. However, default bids by importers that are dispatched in the ISO Real-Time Market will not establish the Dispatch Interval Locational Marginal Prices. Default bids by importers that are dispatched in the ISO Day-Ahead and Hour-Ahead Energy Markets may establish LMPs in those markets.

(e) The ISO shall not use a default bid to determine revised LMPs~~MCPs~~ for periods prior to the imposition of the default bid, except as may be specifically authorized by the Commission.

(f) The Mitigation Measures shall not be applied for the hours when the day-ahead system load forecast exceeds 40,000 MW. However, the bids used during the hours when the Day-Ahead system Demand~~oad~~ exceeds 40,000 MW, even if at least cost~~in economic merit order~~, shall be excluded from the computation of the Reference Levels.

(g) The posting of the MCP may be delayed if necessary for the completion of automated mitigation procedures.

(h) Bids not mitigated under these Mitigation Measures shall remain subject to mitigation by other procedures specified in the ISO Tariff as may be appropriate.

4.3 Sanctions for Physical Withholding

The ISO may report a Market Participant the ISO believes to have engaged in physical withholding, including providing the ISO false information regarding the derating or outage of an Electric Facility, to the Federal Energy Regulatory Commission in accordance with Section 2.3.3.9.5 of the ISO Tariff. In addition, a Market Participant that fails to operate a Generating Unit in conformance with ISO D~~d~~ispatch I~~i~~nstructions shall be subject to the penalties set forth in Section 11.2.4.1.2 of the ISO Tariff.

4.4 Duration of Mitigation Measures

Bids will be mitigated only in the specific hour that they violate the price and market impact thresholds.

5 FERC-ORDERED MEASURES

In addition to any mitigation measures specified above, the ISO 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.

6 DISPUTE RESOLUTION

If a Market Participant has reasonable grounds to believe that it has been adversely affected because a Mitigation Measure has been improperly applied or withheld, it may seek a determination in accordance with the dispute resolution provisions of the ISO Tariff. In no event, however, shall the ISO be liable to a Market Participant or any other person or entity for money damages or any other remedy or relief except and to the extent specified in the ISO Tariff.

7 EFFECTIVE DATE

These Mitigation Measures shall be effective as of the date they are approved by the FERC.

OUTAGE COORDINATION PROTOCOL

* * *

OCP 3.1.2 **~~Quarterly~~ Updates**

Each Participating TO will provide the ISO with quarterly updates of the data provided under OCP 3.1.1 by close of business on the fifteenth (15th) day of each January, April, and July. These updates must identify known changes to any previously planned ISO Controlled Grid facility Maintenance Outages and any additional Outages anticipated over the next twelve months from the time of the report. As part of this update, each Participating TO must include all known planned Outages for the following twelve months. **In addition, on the first day of every month the Participating TO shall provide an update of any known changes to any previously planned Maintenance Outages and additional Outages anticipated over the next two months (i.e. on January 1, the Participating TO would report updated information for February and March).**

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SCHEDULES AND BIDS PROTOCOL

SCHEDULES AND BIDS PROTOCOL

Table of Contents

SCHEDULES AND BIDS PROTOCOL (SBP)

SBP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SBP 1.1 Objectives

The objectives of this Protocol are:

(a) to require the provision of scheduling and bidding data to enable the ISO to undertake its scheduling process as described in the ISO Tariff and in the Scheduling Protocol (SP) taking into account the exercise of Firm Transmission Rights and rights under Existing Contracts for transmission service;

(b) to require the provision of Ancillary Services Schedules and bidding data required by the ISO to enable the ISO to conduct its Ancillary Services procurement ~~auction~~ as described in the ISO Tariff and in the SP; and

(c) to specify the contents of Schedules and to specify in detail the bidding data referred to in the ISO Tariff. The scheduling process and timing of the submission of data referred to are set forth in the SP.

SBP 1.2 Definitions

SBP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff unless otherwise specified. References to SBP are to this Protocol or to the stated paragraph of this Protocol.

SBP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Bid" means an offer to sell Energy and/or Ancillary Services, or to purchase Energy, in ISO Markets.

"Existing Rights" as defined in Section 2.4.4.1.1 of the ISO Tariff, and

"Converted Rights" as defined in Section 2.4.4.2.1 of the ISO Tariff shall have the same meanings where used in this Protocol.

A Physical Scheduling Plant or System Unit shall be treated as a single Generating Unit for purposes of this Protocol, except as otherwise noted.

SBP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) References to time are references to the prevailing Pacific Time.

SBP 1.3 Scope

SBP 1.3.1 Scope of Application to Parties

The SBP applies to the following entities:

(a) Scheduling Coordinators (SCs);

(b) Participating Transmission Owners (PTOs); and

(c) the Independent System Operator (ISO).

SBP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

SBP 2 SCHEDULES AND NOTIFICATIONS

SBP 2.1 Contents of Schedules and ~~Adjustment~~ Bid Data

SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Schedules and Bids ~~bid~~. Except as noted, each of the following data sections can be submitted up to seven (7) days in advance.

SBP 2.1.1 Generation Section of ~~a Balanced~~ Schedule and ~~Adjustment~~ Bid Data

The Generation section of a ~~Balanced~~ Schedule or Bid will include the following information for each Generating Unit:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) name of Generating Unit scheduled or bid;

~~(d) type of Schedule: Preferred or Revised (refer to the SP for details);~~

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

~~(ef) contract reference number associated with the priority type indicated in (d) for Reliability Must-Run Generation;~~

~~(g) Congestion Management flag – “Yes” indicates that any Adjustment Bid submitted under item (k) below should be used;~~

~~(h) publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, “Yes” will indicate that the SC wishes the ISO to publish its Adjustment Bids;~~

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

(~~df~~~~j~~) hourly scheduled Generating Unit output in MWh within the range of the Energy Bid ~~(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), for use in scheduling Existing Contracts or Firm Transmission Rights; ~~and~~

(~~eg~~~~k~~) Energy Bid, consisting of ~~the~~ MW and $/MWh values for each Generating Unit for which a~~n~~ ~~Adjustment~~ Bid is being submitted ~~consistent with SBP 4~~, stated as a staircase function composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of monotonically increasing quantity/price information;~~.~~

(f~~h~~) start-up cost in accordance with ~~as provided in~~ Section 31.2.3.2.3.3.1.1 of the ISO Tariff; ~~and~~

(g) Minimum Load Cost in accordance with~~as provided in~~ Section 31.2.3.2.3.3.1.2 of the ISO Tariff; ~~.~~

(h) flag indicating whether the ISO may use the bid in the Residual Unit Commitment Process (Y/N);

SBP 2.1.2 Demand Section of ~~a Balanced~~ Schedule and ~~Adjustment~~ Bid Data

The Demand section of a ~~Balanced~~ Schedule or Bid will include the following information for each Demand location:

(a) SC’s ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Location Code ~~Demand ID~~ – Demand location (which must be the name of a Load ~~Demand~~ Zone, Customer Aggregation, ~~Load group~~ or bus);

~~(d) type of Schedule: Preferred or Revised (refer to the SP for details);~~

~~(de) hourly scheduled MWh for each Settlement Period of the Trading Day that uses the Existing Contract indicated by the contract reference number for the Generation section of the Schedule or Bid in (e) above (which values should be less than or equal to the hourly scheduled MWh values indicated in this Demand section of the Schedule or Bid (i) below);~~

~~(f) Congestion Management flag – "Yes" indicates that any Adjustment Bid submitted for a Dispatchable Load under item (i) below should be used;~~

~~(g) publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, "Yes" will indicate that the SC wishes the ISO to publish its Adjustment Bids;~~

(de~~h~~) hourly scheduled MWh within the range of the Energy Bid, 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);

(ef~~i~~) Energy Bid, consisting of ~~the~~ MW and $/MWh values for each ~~Dispatchable~~ Load for which a~~n Adjustment~~ Bid is being submitted as provided in Section 31.2.3.2.3.4.4.3 of the ISO Tariff ~~consistent with SBP 4~~, stated as a staircase function composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of monotonically decreasing quantity/price information; ~~and~~

(f~~g~~) minimum curtailment payment for a Particiating~~Dispatchable~~ Load, as provided in Section 31.2.3.2.3.4.4.1 of the ISO Tariff;

(g~~h~~) minimum hourly payment for a Participating~~Dispatchable~~ Load, as provided in Section 31.2.3.2.3.4.4.2 of the ISO Tariff;

(h~~i~~) time required for curtailment following notification to a Participating~~Dispatchable~~ Load, in minutes;

(i~~j~~) minimum off time stating the minimum number of hours a Participating~~Dispatchable~~ Load is willing to be curtailed, in hours;

(j~~k~~) maximum off time stating the maximum number of hours a Participating~~Dispatchable~~ Load is willing to be curtailed, in hours;

(k~~l~~) flag indicating the Participating~~Dispatchable~~ Load bid is available for intra-hour redispatch. If this flag is set to "no" then the bid must be pre-dispatched and not re-dispatched during the real-time operating hour; and

(l) flag indicating whether the ISO may use the bid in the Residual Unit Commitment Process (Y/N).

~~(mj) requisite NERC tagging data.~~

SBP 2.1.3 External Import/Export Section of ~~a Balanced~~ Schedule and ~~Adjustment~~ Bid Data

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

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Scheduling Point (the name);

~~(d) type of Schedule: Preferred or Revised (refer to the SP for details);~~

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

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

(f~~g~~) external Control Area ID;

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

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

(i~~j~~) contract type – transmission (TRNS), Energy (ENGY) or both (TR_EN);

(j~~k~~) Schedule ID (NERC ID number);

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

~~(m) publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, "Yes" will indicate that the SC wishes the ISO to publish its Adjustment Bids;~~

(k~~n~~) complete WSCC tag;

(l~~o~~) hourly scheduled external imports/exports in MWh within the range of the Energy Bid ~~(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;~~ and~~

(m~~p~~) Energy Bid, consisting of ~~the~~ MW and $/MWh values for each external import/export for which a~~n Adjustment~~ Bid is being submitted~~ consistent with SBP 4.~~, of a staircase function composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of monotonically increasing quantity/price information;

(n) ramp rate (MW/minute);

(o) minimum block of hours that bid must be dispatched; and

(p) flag indicating the bid is available for intra-hour redispatch. If this flag is set to "no" then the bid must be pre-dispatched and not re-dispatched during the real-time operating hour; and

(q) flag indicating whether the ISO may use the bid in the Residual Unit Commitment Process (Y/N).

SBP 2.1.4 Inter-Scheduling Coordinator Energy Trades ~~("Internal Imports/Exports")~~ Section of a ~~Balanced~~ Schedule

In the event of an Inter-Scheduling Coordinator Energy Trade, the SCs who are parties to that trade must agree on a Location Code or Trading Hub at ~~Zone in~~ which the trade will be deemed to take place ~~("Trading Point Zone")~~ and notify the ISO accordingly. ~~The purpose of designating a Trading 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:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) trading SC (buyer or seller);

~~(d) type of Schedule: Preferred or Revised (refer to the SP for details);~~

(d~~e~~) Trading Hub or Location Code~~Zone~~;

(e~~f~~) Schedule type – Energy (ENGY);

(f~~g~~) 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 Energy received~~i~~ by~~nternal imports into~~ the SC reported as negative quantities and Energy sent ~~internal exports~~ from the SC reported as positive quantities; and

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

~~(i) publish Adjustment Bid flag – "Yes" indicates that the SC wishes the ISO to publish its Adjustment Bid.~~

(g~~j~~) the Generating Unit or Dispatchable Load that is the source or recipient of Energy traded, if applicable.~~; and~~

~~(k) the MW and $/MWh values for each Generating Unit or Dispatchable Load that is the source or recipient of Energy traded.~~

SBP 2.1.5 Inter-Scheduling Coordinator Ancillary Service Trades ~~("Internal Imports/Exports")~~ Section of a ~~Balanced~~ Schedule

In the event of an Inter-Scheduling Coordinator Ancillary Service Trade, the SCs who are parties to that trade must agree on a Location Code at

~~Trading Zone in~~ which the trade is deemed to take place and notify the ISO accordingly. The Ancillary Service obligations at the Location Code ~~in the Trading Zone~~ of each Scheduling Coordinator will be adjusted to reflect the trade. The Inter-Scheduling Coordinator Ancillary Service Trades section of a Schedule will include the following information for each Inter-Scheduling Coordinator Ancillary Service Trade.

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Trading SC (buyer or seller);

(d) Location Code~~Zone~~;

(e) Schedule type-Regulation Up (ARGU), Regulation Down (ARGD), Spinning Reserve (ASPN), or Non-Spinning Reserve (ANSP) ~~or Replacement Reserve (AREP)~~; and

(f) Contracted MW amount of traded Ancillary Service obligation.

SBP 2.1.6 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 the day prior to the Trading Day, as set forth in the timing requirements of the SP. 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:

(a) SC's ID code:

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

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

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

(e) Contract reference number for each Existing Contract or Firm Transmission Right ~~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");~~

(f) Usage ID (a unique identifier that allows a SC to submit multiple usages for a given contract right ~~Inter-Zonal Interface~~);

(g) 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-SC 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 Energy ~~Adjustment~~ Bids that may also be submitted for any particular resource (S~~s~~ource or S~~s~~ink) 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;

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

(i) Sources and~~or~~ S~~s~~inks, 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 S~~s~~inks). Sources and Sinks must match the points of receipt and points of delivery associated with the Existing Contract or the Firm Transmission Right. Each Energy schedule or Ancillary Service bid or self-provided schedule associated with a particular S~~s~~ource or S~~s~~ink must have an hourly usage schedule that is greater than or equal to the amounts specified on contract usage templates. The S~~s~~ource/S~~s~~ink section of a contract usage template will include the following information (up to five combinations of S~~s~~ources and S~~s~~inks can be specified on a single contract usage template if an SC is submitting the templates in accordance with SBP 7.2(a), or up to 20 combinations of S~~s~~ources and S~~s~~inks if an SC is submitting the templates in accordance with SBP 7.2(b) or SBP 7.2(c));

(1) Type of resource – generation (GEN), load (LOAD), or interchange (INTRCHNGE) ~~or Inter-SC Trade (INTER_SC)~~;

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

(3) Resource_ID2 (required only for individual interchange schedules ~~and Inter-SC Trades~~);

(4) Energy type – firm (FIRM), non-firm (NFIRM), wheeling (WHEEL), dynamic (DYN), Energy (ENGY), Spinning Reserve (CSPN), or 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.

SBP 2.2 Validation of ~~Balanced~~ Schedules and Bids

Each SC 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 and~~, Adjustment~~ Bids~~ and Supplemental Energy bids~~. The SC shall only be allowed to access and manipulate its Schedule and Bid ~~bid~~ data within this workspace. Each area is organized into segments. A segment is used to hold the SC'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 SP) for submission of Schedules. However, a SC can also initiate the stage two validation at any time prior to that deadline, as described in more detail in the SP. If the SC adds a new Schedule or modifies an existing Schedule, that Schedule must be re-validated. SCs must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for ~~Balanced~~ Schedules and Bids.

SBP 2.2.1 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 SC had not exceeded its Security Amount and verify that the SC is certified in accordance with the ISO Tariff. The ISO will further verify that the SC has entered~~inputted~~ valid Generating Unit and Demand Location Code ~~location identification~~. Scheduled Reliability Must-Run Generation will be verified against ISO-instructed quantities.~~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 its ~~it's~~ declared capacity and/or operating limits. If there is an error found during stage one validation, the SC will be notified immediately through WEnet. The SC 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 timing requirements of the SP. 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 SC and allow the SC to view the message(s), to make changes, and to resubmit the contract usage template(s) if it is still within the timing requirements of the SP. The SC is also notified of successful validation via WEnet.

SBP 2.2.2 Stage Two Validation

During stage two validation, Schedules will be checked to determine whether ~~each SC's aggregate Generation and external imports (adjusted for Transmission Losses) and~~ Inter-Scheduling Coordinator ~~Energy~~ Trades (whether purchases or sales) equals the amount and location stated in the counterparty's trade ~~SC's aggregate Demand forecast, including external exports~~. ~~The SC must take into account the applicable Generation Meter Multipliers (GMMs) as described in the SP.~~ The SC will be notified if the counterparty's trade to any Inter-Scheduling Coordinator ~~Ancillary Service~~ Trade has not been submitted, or is infeasible (~~i.~~e.g., if both SCs 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 SC.~~ This validation is performed in accordance with the timing requirement described in the SP. An SC 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~~, as described in the SP, at any time prior to the deadline for submission of ~~Preferred~~ Schedules ~~or Revised Schedules (as the case may be)~~. It is the SC's responsibility to perform such checks, if desired. The SC 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 SC'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 SCs of the mismatch in Energy quantity and/or location. The SC 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 timing requirements of the SP. The SC is also notified of successful validation via WEnet.

SBP 2.3 Schedule Feasibility

The Generation section of a ~~Balanced~~ Schedule or Bid~~, 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 sumbitted for a Generating Unit, applicable to a particular operating hour, should be physically achievable within the applicable operating hour.~~

SBP 2.4 Default Data Requirements

Scheduling Coordinators for all Generating Units shall submit the following operating constraint information to the ISO in the format specified by the ISO and posted on the ISO Home Page:

(a) maximum operating limit, defined as the maximum power output limit of a unit while it is on-line;

(b) minimum dispatchable load level, defined as the minimum power output limit of a unit while it is on-line and able to respond to Dispatch instructions, also referred to as the minimum load;

(c) minimum operating limit, defined as the minimum power output limit of a unit while it is on-line regardless of whether the unit is available for dispatch, which may include operating states such as “flash tank”;

(d) regulating limits, defined as the minimum and maximum power output limits of a unit while it is providing Regulation;

(e) reactive power limits, defined as the minimum and maximum limits of reactive power produced by a unit while it is on-line;

(f) ramp rates associated with varying levels of production, defined as the rate at which a unit increases or decreases its power output to perform schedule changes across time periods, in MW per minute;

(g) minimum up time, defined as the minimum time that a unit must stay on-line between start-up and shutdown, due to physical operating constraints, in minutes;

(h) start-up time, defined as the time required for a unit to start up, from the time of receipt of an ISO notification to start, until the time the generating unit is synchronized to the grid and producing Energy, in minutes;

(i) shutdown time, defined as the time required for a unit to shut down, in minutes;

(j) minimum down time, defined as the minimum time that a unit must stay off-line after the start of a shutdown, including the start-up and shutdown time, in minutes;

(k) time to remain at minimum operating limit, defined as the amount of time that a unit must be run at or near its minimum operating limit before it can be restored to its minimum dispatchable load level (equal to zero if the minimum dispatchable load level and the minimum operating limit are the same);

(l) time to reach minimum dispatchable load level, defined as the amount of time required for a unit to move from its minimum operating limit to its minimum dispatchable load level (equal to zero if these levels are the same);

(m) maximum number of daily start-ups, defined as the maximum number of times that a unit is allowed to shutdown and start-up within a day, in events per day;

(n) start-up auxiliary power data, defined as the electrical power used by a unit during start-up;

(o) emissions rates and costs, measured as the pounds of emissions~~NOx~~ per MWh for each type of emissions at the same resource loading points that are used to provide heat input data or production cost data (discussed below) and the cost of emissions in $ per pound for each type of emissions;

(p) start-up emissions data and costs, measured as the pounds of emissions produced during start-up of a unit for each type of emissions and the cost of emissions in $ per pound for each type of emissions;

(q) Energy limitations, which are limits on the amount of power that can be produced by a unit over the Day-Ahead time horizon.

Scheduling Coordinators for Gas-Fired Generating Units shall submit the following additional operating data in the format specified by the ISO and posted on the ISO Home Page:

(a) heat input data, stating the average heat rate (BTU/kWh) at up to 11 levels of production, representing a range of resource loading points that must include data at or near the minimum production level (minimum load) and maximum output; and

(b) start-up fuel data, stating the fuel use, in BTU per start, expected for the start-up of a generator that has been off-line for representative periods of time. Start-up fuel use may be provided for up to ten representative amounts of time that a generator has been off-line (including shutdown and start-up time), such as hot starts, cold starts, and other conditions.

Scheduling Coordinators for Generating Units that are not gas-fired shall submit the following additional operating data in the format specified by the ISO and posted on the ISO Home Page:

(a) production cost data, stating the average operating cost ($/MWh) at up to 11 levels of production representing a range of resource loading points that must include data at or near the minimum production level (minimum load) and maximum output;

(b) start-up cost data, stating the cost in dollars per start expected for the start-up of a generator that has been off-line for representative periods of time, which may be provided for up to ten representative amounts of time that a generator has been off-line (including shutdown and start-up time), such as hot starts, cold starts, and other conditions;

(c) fuel type; and

(d) applicable fuel index, available from public data sources or standard trade publications, for the ISO to use in updating the provided production cost data and start-up cost data.

Scheduling Coordinators must file periodic updates of this information at the direction of FERC or the ISO, or when the Scheduling Coordinator is aware that significant changes in the data have occurred. In the event that Scheduling Coordinators do not supply the required data, the ISO may use data available from other sources, including a current or previous Reliability Must-Run Contract with the Generator, a

Participating Generator Agreement listing that Generating Unit, or data for similar technologies.

SBP 3 EXISTING CONTRACTS FOR TRANSMISSION SERVICE

SBP 3.1 Application of SBP 3 to Rights under Existing Contracts

SBP 3.1.1 Existing Rights

The provisions of Sections 2.4.3 and 2.4.4 of the ISO Tariff shall, with respect to the exercise of Existing Rights following the ISO Operations Date, be implemented in accordance with this SBP 3 and such other operational protocols as may be developed on a case by case basis pursuant to these sections. The objective of this SBP 3 is to properly treat Existing Rights in accordance with the ISO Tariff and to minimize the need for other operational protocols.

SBP 3.1.2 Converted Rights

This SBP 3 shall have no application to the exercise of Converted Rights other than as set forth in Section 2.4.4.3 of the ISO Tariff.

SBP 3.2 Responsible Participating Transmission Owners

For each Existing Contract, the party providing transmission service (the “Responsible PTO”) shall be responsible for the submission of transmission rights/curtailment instructions (“instructions”) to the ISO under this SBP on behalf of the holders of Existing Rights, unless the parties to the Existing Contract agree otherwise. For the purposes of this Protocol, such otherwise agreed party will be acting in the role of Responsible PTO. In accordance with the ISO Tariff, the parties to Existing Contracts will attempt to jointly develop and agree on any instructions that will be submitted to the ISO. To the extent there is more than one PTO providing transmission service under an Existing Contract or there is a set of Existing Contracts which are interdependent from the point of view of submitting instructions to the ISO involving more than one PTO, the relevant PTOs will designate a single PTO as the Responsible PTO and will notify the ISO accordingly. If no such Responsible PTO is designated by the relevant PTOs or the ISO is not notified of such designation, the ISO shall designate one of them as the Responsible PTO and notify the relevant PTOs accordingly.

SBP 3.3 Instructions Defining Transmission Service Rights

SBP 3.3.1 Data Requirements

The Responsible PTO with respect to an Existing Contract or set of interdependent Existing Contracts is required to submit to the ISO, in accordance with the timing requirements of SBP 3.3.5, the instructions that are necessary to implement the exercise of the Existing Rights in accordance with the ISO Tariff. These instructions will be submitted to the ISO electronically, by the Responsible PTO, utilizing a form provided by the ISO in a format similar to the one set out in the Appendix to this Protocol (the “Transmission Rights/Curtailment Instructions Template”). The instructions will include the following information at a minimum and such other information as the ISO may reasonably require to enable it to carry out its functions under the ISO Tariff and ISO Protocols (the letters below correspond with the letters of the instructions template in the Appendix to this Protocol):

(a) a unique contract reference number (Existing Contract reference number that will be assigned by the ISO and communicated to the Responsible PTO on the completed instruction and that references a single Existing Contract or a set of interdependent Existing Contracts; the provisions of SBP 3.4 will apply to the validation of scheduled uses of Existing Contract transmission rights);

(b) whether the instruction can be exercised independent of the ISO's day-to-day involvement (Yes/No);

(c) name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Responsible PTO;

(d) name(s) and number(s) of Existing Contract(s);

(e) path name(s) and location(s) (described in terms of the Location Codes for ~~Zones in which~~ the point(s) of receipt and point(s) of delivery ~~are located~~);

(f) names of the party(ies) to the Existing Contract(s);

(g) SC ID code: the ID number of the SC who will submit Schedules which make use of the Existing Contract(s) for the party(ies) indicated in (f);

(h) type(s) of rights, by rights holder, by Existing Rights;

(i) type(s) of service, by rights holder, by Existing Contract (firm, conditional firm, or non-firm), with priorities for firm and conditional firm transmission services ~~indicated in Schedules using Adjustment Bids~~ as described in the SP;

(j) amount of transmission service, by rights holder, by Existing Contract expressed in MW;

(k) for Day-Ahead scheduling purposes, the time of the day preceding the Trading Day at which the SC submits Schedules to the ISO referencing the Existing Contract(s) identified in the instructions;

(l) for Hour-Ahead or real time scheduling purposes, the number of minutes prior to the start of the Settlement Period of delivery at which the SC may submit Schedule adjustments to the ISO regarding the Existing Rights under the Existing Contract(s) identified in the instructions;

(m) whether or not real time modifications to Schedules associated with Existing Rights are allowed at any time during the Settlement Period;

(n) Service period(s) of the Existing Contract(s);

(o) any special procedures which would require curtailments to be implemented by the ISO in any manner different than that specified in SBP 3.3.2. Any such instructions submitted to the ISO must be clear, unambiguous, and not require the ISO to make any judgments or interpretations as to the meaning, intent, results, or purpose of the curtailment procedures or the Existing Contract (otherwise, they will not be accepted by the ISO); and

(p) any special procedures relating to curtailments during emergency conditions. Any such instructions submitted to the ISO must be clear, unambiguous, and not require the ISO to make any judgments or interpretations as to the meaning, intent, results, or purpose of the curtailment procedures or the Existing Contract (otherwise, they will not be accepted by the ISO).

SBP 3.3.2 Curtailment under Emergency and Non-Emergency Conditions

SBP 3.3.2.1 Emergency Conditions

To the extent practicable, the ISO shall allocate necessary curtailments of Existing Rights or Non-Converted Rights under emergency conditions in accordance with the instructions submitted by the Responsible PTO pursuant to SBP 3.3.1. If circumstances prevent the ISO's compliance with such instructions, the ISO shall allocate such curtailments in a non-discriminatory manner consistent with Good Utility Practice.

SBP 3.3.2.2 Non-Emergency Conditions

Unless otherwise specified by the Responsible PTO in the instructions that it submits to the ISO under SBP 3.3.1, the ISO will allocate any necessary curtailments under non-emergency conditions, *pro rata*, among holders of Existing Rights, at particular Scheduling Points and/or on particular contract paths, in the order of: (1) non-firm, (2) each priority of conditional firm, and (3) each priority of firm rights. Priorities for firm and conditional firm transmission service are indicated using contract usage templates, as described in the SBP 2.1.6 and in the SP.

SBP 3.3.3 [Not Used]

SBP 3.3.4 Instructions that cannot be Exercised Independent of the ISO's Day-to-Day Involvement

Those instructions that define the transmission rights within which uses may be scheduled or curtailed and that cannot be exercised independent of the ISO's day-to-day involvement must be submitted to the ISO in accordance with SBP 3.3.1. These instructions will be provided by the Responsible PTO to the ISO for implementation unless the parties to the Existing Contracts otherwise agree that the rights holder will do so. For these instructions, the SCs representing the holders of Existing Rights will submit their Schedules to the ISO for implementation in accordance with the instructions.

SBP 3.3.5 Timing of Submission of Instructions to ISO

SBP 3.3.5.1 Initial Submittal of Instructions

The Responsible PTOs shall submit instructions to the ISO associated with Existing Contracts or sets of interdependent Existing Contracts thirty (30) days prior to either (a) the ISO Operations Date or (b) the date on which the scheduling or curtailment of the use of the Existing Rights is to commence pursuant to Sections 2.4.3 or 2.4.4 of the ISO Tariff.

SBP 3.3.5.2 Changes to Instructions

Updates or changes to the instructions must be submitted to the ISO by the Responsible PTO, on an as needed or as required basis determined by the parties to the Existing Contracts. The ISO will implement the updated or changed instructions as soon as practicable but not later than seven (7) days after receiving clear and unambiguous details of the updated or changed instructions. If the ISO finds the instructions to be inconsistent with respect to the ISO Protocols or the ISO Tariff, the ISO will notify the Responsible PTO within forty-eight (48) hours after receipt of the updated or changed instructions indicating the nature of the problem and allowing the Responsible PTO to resubmit the instructions as if they were new, updated or changed instructions to which the provisions of this SBP 3.3 will apply. If the ISO finds the updated or changed instructions to be acceptable, the ISO will time-stamp the updated instructions as received, confirm such receipt to the Responsible PTO, and indicate the time at which the updated instructions take effect if prior to the seven (7) day deadline referred to above.

SBP 3.4 Validation of Existing Contract Schedules

Each Schedule submitted to the ISO by a SC representing a rights holder to an Existing Contract must include a valid contract reference number in accordance with SBP 3.3. ~~If the Schedule includes an Inter-Scheduling Coordinator Trade, only one of the SCs 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 SCs which are parties to an Inter-Scheduling Coordinator Trade submit contract reference numbers~~, the ISO will issue an error message to the SC via the WEnet (as described in SBP 2.2.1) and indicate the nature of the problem. The ISO will assist the SC, within reason, in resolving the problem so that the SC is able to submit the Schedule successfully as soon as possible within the timing requirements of the SP. If the SC 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 SC notified by the ISO's issuance of an invalidated usage information template.

SBP 4 **[Not Used] ~~ADJUSTMENT BIDS~~**

~~Adjustment Bids will be used by the ISO for 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. These Adjustment Bids will not be transformed into Supplemental Energy bids. However, these Adjustment Bids are treated as standing offers to the ISO and may be used by the ISO in the Real Time Market for the purpose of managing Intra-Zonal Congestion and Overgeneration conditions.~~

SBP 4.1 **[Not Used] ~~Content of Adjustment Bids~~**

~~Adjustment Bids are contained in Preferred Schedules and Revised Schedules submitted by SCs 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 SC is required to submit a preferred operating point for each Generating Unit, Dispatchable Load and external import/export (these quantities are presented in the SC's submitted Schedule as "Hourly MWh"). The SC'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.~~

SBP 4.2 **[Not Used] ~~Format of Adjustment Bids~~**

~~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 SC's Balanced Schedule and must be related to each Generating Unit, Dispatchable Load and external import/export. SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Adjustment Bids.~~

SBP 4.3 **[Not Used] ~~Timing of Submission of Adjustment Bids~~**

~~The specific timeline requirements for the submission of Adjustment Bids in both the Day-Ahead Market and the Hour-Ahead Market are described in the SP. 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 SC in its Revised Day-Ahead Schedule, if any.~~

SBP 4.4 **[Not Used] ~~Publication of Adjustment Bids~~**

~~The ISO will publish Adjustment Bids in accordance with applicable provisions of the ISO Tariff governing the disclosure of bid data.~~

SBP 4.5 **[Not Used] ~~Validation of Adjustment Bids~~**

SBP 4.5.1 **[Not Used] ~~Invalidation~~**

~~The absence of an Adjustment Bid in a SC's Preferred Schedule or Revised Schedule will not affect the validation since SCs are not required to submit Adjustment Bids. If an Adjustment Bid is contained in the SC'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 SC 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 SC's notification screen which will specify the nature of the error. The SC 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 SC is also notified of successful validation via WEnet. The SCs must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Adjustment Bids.~~

SBP 4.5.2 **[Not Used] ~~Validation Checks~~**

~~The ISO's stage one validation checks are performed automatically, whenever Schedules and Adjustment Bids are submitted, as described in the SP. The ISO's stage two validation is performed automatically in accordance with the timing requirements described in the SP. An SC 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, as described in the SP, at any time prior to the deadline for submission of Preferred Schedules or Revised Schedules. It is a SC's responsibility to perform such checks.~~

SBP 4.6 **[NOT USED]**

SBP 5 **ANCILLARY SERVICES**

SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Ancillary Services schedules and bids. Additionally, SCs should refer to the Ancillary Services bid evaluation and scheduling principles contained in the SP. As also described in the SP, the resources constituting a System Unit which submitted Ancillary Services bids or schedules and which, as a result, has been accepted by the ISO to supply Ancillary Services in a Settlement Period must be disclosed to the ISO one (1) hour prior to the start of the Settlement Period.

SBP 5.1 **Content of Ancillary Services Schedules and Bids**

Ancillary Services in the Day-Ahead Market and the Hour-Ahead Market are comprised of the following: Regulation, Spinning Reserve, and

Non-Spinning Reserve ~~and Replacement Reserve~~. Each Generating Unit (including Physical Scheduling Plants), System Unit, Dispatchable Load ~~Curtailable Demand~~ or System Resource for which a SC wishes to submit Ancillary Services Schedules and Bids ~~bids~~ must meet the requirements set forth in the Ancillary Services Requirements Protocol (ASRP). For each Ancillary Service offered to the ISO Market ~~auction~~ or self-provided, SCs must also provide ~~include a bid price for~~ an Energy Bid in the form described in SBP 2 ~~of a staircase function composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of quantity/price information. These staircase functions must be either monotonically non-decreasing (Generating Units, System Units, and System Resources) or monotonically non-increasing (Curtailable Demands)~~. The same resource capacity may be included in ~~offered into~~ more than one ISO Ancillary Service Bid ~~auction~~ at the same time (the ~~sequential~~ evaluation of such multiple offers between Ancillary Services markets to eliminate double counting of capacity is described in the SP). ~~In each category of Ancillary Service, the reference to "Revised" types of Schedules indicates a submittal which is part of a Revised Day-Ahead Schedule as described in the SP.~~ Each of the following data sections can be submitted up to seven (7) days in advance. There is no provision for external exports with regard to Ancillary Services bids. The functionality necessary to accept such bids does not exist in the ISO scheduling software.

SBP 5.1.1 Regulation

SBP 5.1.1.1 Regulation: Generating Units or System Units

Each SC desiring to self-provide Regulation or to bid ~~participate in the ISO's~~ Regulation capacity ~~auction~~ will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Regulation Ancillary Service (ANC_SRVC) ~~or Revised Regulation Ancillary Service (REVISED_ANC_SRVC)~~;

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Generating Unit or System Unit ID code;

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

(f) upward and downward range of Generating Unit or System Unit capacity over which the Generating Unit or System Unit is offering to provide Regulation; and

~~(g) Generating Unit or System Unit operating limits (high and low MW);~~

~~(h) Generating Unit or System Unit ramp rate (MW/minute); [and]~~

(g~~i~~) bid price for Regulation capacity ($/MW), stated separately for Regulation Up and Regulation Down[~~; and~~

~~(j) bid price for regulating Energy if called upon ($/MWh) (required for validation bid only)~~].

SBP 5.1.1.2 Regulation: External Imports

Each SC desiring to self-provide Regulation or to bid ~~participate in the ISO's~~ Regulation capacity ~~auction~~ will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: (Regulation Ancillary Service);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name)

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

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WSCC tag;

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

(j) in the case of Existing contracts, the applicable contract reference number;

(k) upward and downward range of System Resource capacity over which the System Resource is offering to provide Regulation;

(l) System Resource operating limits (high and low MW);

(m) ramp rate (MW/minute); [*and]*

(n) bid price for Regulation capacity ($/MW) stated separately for Regulation Up and Regulation Down[~~; and~~

~~(o) bid price for Regulation Energy if called upon ($/MWh)~~].

SBP 5.1.2 Spinning Reserve

SBP 5.1.2.1 Spinning Reserve: Generating Units or System Units

Each SC desiring to self-provide Spinning Reserve or to bid ~~participate in the ISO's~~ Spinning Reserve capacity ~~auction~~ will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC)~~ or Revised Spinning Reserve Ancillary Service (REVISED_ANC_SRVC)~~;

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Generating Unit or System Unit ID code;

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

~~(f) Generating Unit or System Unit operating limits (high and low MW);~~

(f~~g~~) Spinning Reserve capacity (MW) synchronized to the system, immediately responsive to system frequency, and available within ten (10) minutes; and

~~(h) Generating Unit or System Unit ramp rate (MW/minute); [*and*]~~

(g~~i~~) bid price for Spinning Reserve capacity ($/MW);

(h) an indication as to whether the capacity reserved was available to provide Imbalance Energy only during an unplanned Outage, a Contingency, or an imminent or actual System Emergency.[~~; and~~

~~(j) bid price for Spinning Reserve Energy if called upon ($/MWh)~~].

SBP 5.1.2.2 Spinning Reserve: External Imports/Exports

Each SC desiring to bid or self-provide Spinning Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC)~~ or Revised Spinning Reserve Ancillary Service (REVISED_ANC_SRVC)~~;

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name);

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

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WSCC tag;

(i) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule~~ which must be set to "NO", indicating a self-provided schedule, until such time as the ISO's scheduling system is able to support Ancillary Services bids from external imports/exports~~;

(j) export flag, a "YES" indicates an external export and a "NO" indicates an external import;

(k) In the case of Existing Contracts, the applicable contract reference number;

(l) Spinning Reserve capacity (MW) synchronized to the system, immediately responsive to system frequency, and available at the point of Interchange with the ISO Control Area within ten (10) minutes of the ISO calling for the import; [*and]*

(m) ramp rate (MW/minute)

(n) an indication as to whether the capacity reserved was available to provide Imbalance Energy only during an unplanned Outage, a Contingency, or an imminent or actual System Emergency. [~~; and~~

~~(n) bid price for Spinning Reserve Energy if called upon ($/MWh)~~].

SBP 5.1.3 Non-Spinning Reserve

SBP 5.1.3.1 Non-Spinning Reserve: Generating Units or System Units

Each SC desiring to self-provide Non-Spinning Reserve or to bid ~~participate in the ISO's~~ Non-Spinning Reserve capacity ~~auction~~ will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) ~~or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC)~~;

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Generating Unit or System Unit ID code;

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

(f) time to synchronize following notification (less than ten (10) minutes mandatory);

(g) Non-Spinning Reserve capacity available within ten (10) minutes following notification (MW); and

~~(h) Generating Unit or System Unit operating limits (high and low MW);~~

~~(i) Generating Unit or System Unit ramp rate (MW/minute); [*and]*~~

(h~~j~~) bid price for Non-Spinning Reserve capacity ($/MW)

(i) an indication as to whether the capacity reserved was available to provide Imbalance Energy only during an unplanned Outage, a Contingency, or an imminent or actual System Emergency. [~~; and~~

~~(k) bid price for Non-Spinning Reserve Energy if called upon ($/MWh)~~].

SBP 5.1.3.2 Non-Spinning Reserve: ~~Curtailable Demands~~ Dispatchable Load

Each SC desiring to self-provide Non-Spinning Reserve or to bid ~~participate in the ISO's~~ Non-Spinning Reserve capacity ~~auction~~ will submit the following information for each relevant Dispatchable Load ~~Curtailable Demand~~ for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) ~~or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC)~~;

(b) SC's ID code;

(c) type of market (Day-Ahead and Hour-Ahead) and Trading Day;

(d) available Dispatchable Load ~~Curtailable Demand ID~~ code;

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

~~(f) maximum allocation curtailment duration (hours) (CURT_HR);~~

~~(g) time to interruption following notification (minutes);~~

(f) time to interrupt (must be less than ten minutes);

(g~~f~~~~h~~) amount of Dispatchable Load ~~Curtailable Demand~~ that can be interrupted within ten (10) minutes following notification (MW); ~~[*and*]~~

(h~~g~~~~i~~) bid price for Non-Spinning Reserve capacity ($/MW); and

(i) an indication as to whether the capacity reserved was available to provide Imbalance Energy only during an unplanned Outage, a Contingency, or an imminent or actual System Emergency. [~~;~~ ~~and~~

~~(j) bid price for Non-Spinning Reserve Energy if called upon ($/MWh)~~].

SBP 5.1.3.3 Non-Spinning Reserve: External Imports/Exports

Each SC desiring to bid or self-provide Non-Spinning Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) ~~or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC)~~;

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name);

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

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WSCC tag;

(i) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule ~~which must be set to "NO", indicating a self-provided schedule~~;

(j) export flag, a "YES" indicates an external export and a "NO" indicates an external import;

(k) In the case of Existing Contracts, the applicable contract reference number;

(l) time to synchronize following notification (less than ten (10) minutes mandatory);

(m) Non-Spinning Reserve capacity (MW) available at the point of Interchange with the ISO within ten (10) minutes of the ISO calling for the import; ~~[*and*]~~

(n) ramp rate (MW/minute)[~~; and~~ and

(o) ~~(o)~~ Bid price for Non-Spinning Reserve capacity ($/MW); and

(p) an indication as to whether the capacity reserved was available to provide Imbalance Energy only during an unplanned Outage, a Contingency, or an imminent or actual System Emergency.

~~(o) bid price for Non-Spinning Reserve Energy if called upon ($/MWh)~~].

SBP 5.1.4 [Not Used] ~~Replacement Reserve~~

SBP 5.1.4.1 [Not Used] ~~Replacement Reserve: Generating Units or System Units~~

~~Each SC desiring to self-provide Replacement Reserve or to participate in the ISO's Replacement Reserve auction will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:~~

~~(a) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);~~

~~(b) SC's ID code;~~

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

~~(d) Generating Unit or System Unit ID code;~~

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

~~(f) time to synchronize following notification (less than sixty (60) minutes mandatory);~~

~~(g) Generating Unit or System Unit operating limits (high and low MW);~~

~~(h) Replacement Reserve capacity available within sixty (60) minutes following notification (MW);~~

~~(i) Generating Unit or System Unit ramp rates (MW/minute); [*and]*~~

~~(j) bid price for Replacement Reserve capacity ($/MW)[; and~~

~~(k) bid price for Replacement Reserve Energy if called upon ($/MWh)].~~

SBP 5.1.4.2 [Not Used] ~~Replacement Reserve: Curtailable Demands~~

~~Each SC desiring to self-provide Replacement Reserve or to participate in the ISO's Replacement Reserve auction will submit the following information for each relevant Curtailable Demand for each Settlement Period of the relevant Trading Day:~~

~~(a) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);~~

~~(b) SC's ID code;~~

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

~~(d) Curtailable Demand ID code;~~

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

~~(f) maximum allocation curtailment duration (hours) (CURT_HR);~~

~~(g) time to reduction following notification (minutes);~~

~~(h) amount of Curtailable Demand that can be interrupted within sixty (60) minutes following notification (MW);~~

~~(i) Curtailable Demand reduction rate (MW/minute); [*and]*~~

~~(j) bid price for Replacement Reserve capacity ($/MW)[; and~~

~~(k) bid price for Replacement Reserve Energy if called upon ($/MWh)].~~

SBP 5.1.4.3 [Not Used] ~~**Replacement Reserve: External Imports**~~

~~Each SC desiring to bid or self-provide Replacement Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:~~

~~(a) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);~~

~~(b) SC's ID code;~~

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

~~(d) Scheduling Point (the name);~~

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

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

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

~~(h) complete WSCC tag;~~

~~(i) preferred bid flag, which must be set to "NO", indicating a self-provided schedule, until such time as the ISO's scheduling system is able to support Ancillary Services bids from external imports;~~

~~(j) in the case of Existing Contracts, the applicable contract reference number;~~

~~(k) time to synchronize following notification (less than sixty (60) minutes mandatory);~~

~~(l) Replacement Reserve capacity (MW); [*and]*~~

~~(m) ramp rate (MW/minute)[; and~~

~~(n) bid price for Replacement Reserve Energy if called upon ($/MWh)].~~

SBP 5.2 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 SC notifying the SC of the errors in the Schedules and/or bids. SCs 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:

SBP 5.2.1 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, or Non-Spinning Reserve ~~or Replacement Reserve~~ does not exceed the available capacity for Regulation and~~,~~ Operating Reserves ~~and Replacement Reserve~~ on the Generating Units, System Units, Dispatchable Load ~~Curtailable Demands~~ and external imports/exports scheduled or bid. The SC 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 SC's notification screen which will specify the nature of the error. The SC 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 SC is also notified of successful validation via WEnet.

SBP 5.2.2 Stage Two Validation

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

SBP 5.2.3 Validation Checks

The ISO's stage one validation checks are performed automatically whenever Ancillary Services Schedules and bids are submitted, as described in the SP. The ISO's stage two validation is performed automatically in accordance with the timing requirements described in the SP. A SC 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 SC's responsibility to perform such checks.

SBP 5.3 [Not Used] ~~Buy Back of Ancillary Services~~

~~A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resoruce successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduing Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be at the Market Clearing Price in the Hour-Ahead Market for the same Settlement Period for the Ancillary Service capacity concerned.~~

SBP 6 [Not Used] ~~[SUPPLEMENTAL] ENERGY BIDS~~

~~There is no requirement for SCs to submit Supplemental Energy bids~~. ~~Supplemental Energy bids submitted, however, are available to the ISO for procurement and use for Imbalance Energy, additional Voltage Support and Congestion Management in the Real Time Market.~~

SBP 6.1 [Not Used] ~~Content of Supplemental Energy Bids~~

SBP 6.1.1 [Not Used] ~~Generation Section of Supplemental Energy Bid Data~~

~~Each SC offering Supplemental Energy to the ISO will submit the following information for each Generating Unit for each Settlement Period:~~

~~(a) SC's ID code;~~

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

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

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

~~(e) the MW and $/MWh values for each Generating Unit for which a Supplemental Energy bid is being submitted consistent with this SBP 6.~~

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

SBP 6.1.2 **[Not Used]** ~~**Demand Section of Supplemental Energy Bid Data**~~

~~Each SC offering Supplemental Energy to the ISO will submit the following information for each Demand for each Settlement Period:~~

~~(a) SC's ID code;~~

~~(b) name of Demand; and~~

~~(c) the MW and $/MWh values for each Demand for which a Supplemental Energy bid is being submitted consistent with this SBP 6.~~

SBP 6.1.3 **[Not Used]** ~~**External Import Section of Supplemental Energy Bid Data**~~

~~Each SC offering Supplemental Energy to the ISO will submit the following information for each external import for each Settlement Period;~~

~~(a) SC'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 WSCC tag;~~

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

~~(h) the MW and $/MWh values for each external import for which a Supplemental Energy bid is being submitted consistent with this SBP 6;~~

SBP 6.2 **[Not Used]** ~~**Format of Supplemental Energy Bids**~~

~~The SC's preferred operating point for each resource must be within the range of the Supplemental 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 Supplemental Energy Bids must be in the form of a monotonically non-decreasing staircase function for Generating Units and external imports and a monotonically non-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 a single ramp rate associated with the entire MW range. SCs must comply with the ISO Data Templates and~~

~~Validation Rules document, which contains the format for submission of Supplemental Energy Bids.~~

SBP 6.3 **[Not Used] ~~Timing of Submission of Supplemental Energy Bids~~**

~~For specific timeline requirements for the submission of [Supplemental] Energy Bids see the Dispatch Protocol.~~

SBP 6.4 **[Not Used] ~~Validation of Supplemental Energy Bids~~**

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

SBP 7 **INTERFACE REQUIREMENTS**

SBP 7.1 **WEnet**

WEnet provides the backbone on which any of three communications mechanisms will be utilized. These are:

(a) use of a web browser such as Netscape;

(b) use of File Transfer Protocol (FTP); or

(c) use of an Application Programming Interface (API).

Details of the technical aspects of each of these mechanisms, including information on how to change mechanisms and back-up procedures for individual SC failures, will be made available by the ISO to SCs on request. It is assumed that each SC has made application for and signed a Scheduling Coordinator Agreement. As such, each SC will already be familiar with and have arranged the mechanism, including security arrangements, by which it will initially communicate with the ISO.

SBP 7.2 **Templates**

The ISO Data Templates and Validation Rules document provides a description of the templates which will be utilized to enter data into the ISO's systems. For each of the three communications mechanisms, data entry is as follows:

(a) direct entry of data into the template screens through the use of a browser;

(b) upload of ASCII delimited text through use of an upload button on the template screens which activates the FTP mechanism; or

(c) use of the SC's own API.

SBP 7.3 Public/Private Information

Through the use of the security provisions of WEnet, some data will be provided on a confidential basis (such as individual SC Schedules and bids) and other ISO data (such as ISO forecasts of Demand) will be published on the public section of WEnet and be available to anyone.

SBP 7.4 Individual SC Communication Failure

If there is a failure of communications with a SC, then, at the ISO's discretion, the SC may communicate by facsimile, but only if the ISO and the SC have communicated by telephone in advance.

SBP 7.5 Failure/Corruption of WEnet

Based on the designed reliability of the WEnet, there is no external back-up communications system. In the extremely unlikely event of WEnet failure, communications will be lost to all SCs and the ISO will use the latest valid information available to operate until restoration of WEnet.

SBP 8 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

SBP APPENDIX

TRANSMISSION RIGHTS/CURTAILMENT INSTRUCTIONS TEMPLATE

Transmission Rights/Curtailment Instructions Template

(a) Contract Ref #	(b) Ind Imp	(c) Contact Person
[a single number]	[yes/no]	[phone number] [name(s)]

Submitted By PTO: ______
Date Received By ISO: ______
Date Accepted By ISO: ______

	(e) Path Name(s) and Location(s)						(i)(j) Types and Amounts of Transmission Service			(k) DA	(l) HA	(m) RT	(n) Service Period	
(d) Contract Name(s)/Number(s)	Path Name(s)	POR Zone	POD Zone	(f) Party	(g) SC ID	(h) ER/NCR	Firm /1/	CF /1/	N-F	(hour-ending)	(minutes)	(yes/no)	Beginning	Ending
[name/number 1]		[zone name]	[zone name]	[party 1] [party 2] [party n]	[sc id 1] [sc id 2] [sc id n]	[er] [ncr] [er]	[MW] ["] ["]	[MW] ["] ["]	[MW] ["] ["]	[1400]	[30] [n/a] [20]	[yes] [no] [yes]	[hh/dd/mm/yy] ["] ["]	[hh/dd/mm/yy] ["] ["]
[name/number 2]		[zone name]	[zone name]	[party 1] [party 2] [party n]	[sc id 1] [sc id 2] [sc id n]	[er] [ncr] [er]	[MW] ["] ["]	[MW] ["] ["]	[MW] ["] ["]	[1400]	[20] [n/a] [20]	[yes] [no] [yes]	["] ["] ["]	["] ["] ["]
[name/number n]		[zone name]	[zone name]	[party 1] [party 2] [party n]	[sc id 1] [sc id 2] [sc id n]	[er] [ncr] [er]	[MW] ["] ["]	[MW] ["] ["]	[MW] ["] ["]	[1500]	[20] [n/a] [20]	[yes] [no] [yes]	["] ["] ["]	["] ["] ["]

(o) Non-Emergency Curtailments

[If other than pro rata, attach spreadsheet for ISO to use in allocating curtailments to rights holders between the indicated zones. Otherwise, indicate "pro rata" here.]

(p) Emergency Curtailments

[Describe special procedures/requirements here. Indicate "N/A" if none.]

/1/ Priorities for firm and conditional firm transmission service are indicated ~~in Schedules using Adjustment Bids~~ as described in the SP.

SCHEDULING PROTOCOL

SCHEDULING PROTOCOL

Table of Contents

SCHEDULING PROTOCOL (SP)

SP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SP 1.1 Objectives

The objectives of this Protocol are:

(a) to process the scheduling input data (submitted to the ISO under the Ancillary Service Requirements Protocol (ASRP), the Demand Forecasting Protocol (DFP), and the Schedules and Bids Protocol (SBP)) in order to develop Final Schedules for the Day-Ahead and Hour-Ahead Markets (real time management of the ISO Controlled Grid is addressed in the Dispatch Protocol (DP));

(b) to provide for the scheduling of the use of Firm Transmission Rights and use of transmission service rights under Existing Contracts;

(c) to assist the ISO in purchasing Ancillary Services; ~~and~~

(d) to manage Congestion;~~.~~

(e) to clear the Energy markets; and

(f) to commit resources.

SP 1.2 Definitions

SP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff. References to SP are to this Protocol or to the stated paragraph of this Protocol.

SP 1.2.2 ~~Special Definitions for this Protocol~~ [Not Used]

~~In this Protocol, the following words and expressions shall have the meanings set opposite them:~~

~~**"ISO Home Page"** means the ISO internet home page at http://www.caiso.com/iso or such other internet address as the ISO shall publish from time to time.~~

SP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) References to time are references to the prevailing Pacific time.

SP 1.3 Scope

SP 1.3.1 Scope of Application to Parties

The SP applies to the following entities:

(a) Scheduling Coordinators (SCs);

(b) Utility Distribution Companies (UDCs);

(c) Participating Transmission Owners (PTOs);

(c) interfacing Control Area operators in accordance with Inter-Control Area agreements entered into with the ISO, to the extent the agreement between the Connected Entity and the ISO so provides; and

(d) the Independent System Operator (ISO).

SP 1.3.2 Liability of ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

SP 2 INTERFACE REQUIREMENTS

The WEnet interface requirements and associated information requirements are described in the SBP.

SP 3 Time Lines

(a) Consistent with Sections 2.2.12.1 and 2.5.2.2 of the ISO Tariff, the ISO may implement any temporary variation or waiver of timing requirements contained in this SP (including the omission of any step) if any of the following criteria are met:

(i) 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) the ISO requires additional time to fulfill its responsibilities pursuant to Section 2.2.2 of the ISO Tariff;

(iii) problems with data or the processing of data cause a delay in receiving or issuing Schedules or publishing information on the WEnet;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Schedules or publishing information on the WEnet; or

(v) 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 Controlled Grid during an actual System Emergency.

(b) If the ISO temporarily implements a waiver or variation of such timing requirements (including the omission of any step) consistent with Section 2.2.12.1 of the ISO Tariff and SP 3(a), the ISO will publish the following information on WEnet as soon as practicable:

(i) the exact timing requirements affected;

(ii) details of any substituted timing requirements;

(iii) an estimate of the period for which this waiver or variation will apply; and

(iv) reasons for the temporary waiver or variation.

(c) 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.

(d) 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.

(e) The incorporation of the scheduling of the use of rights under Existing Contracts into the ISO's Day-Ahead, Hour-Ahead and real time processes is additionally described in SP 7 and in the SBP.

SP 3.1 ~~Balanced~~ Schedules

SP 3.1.1 ~~Types of~~ Balanced Schedules

A Scheduling Coordinator's portfolio is not required to be balanced relative to scheduled Generator, Load and System Resources. A Scheduling Coordinator may voluntarily submit a Balanced Schedule.

~~A Schedule shall be treated as a Balanced Schedule when the SC's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether~~

~~purchases or sales), equal the SC's aggregate Demand forecast, including external exports, with respect to all entities for which the SC schedules. On an interim basis, the ISO may assist SCs in matching Inter-Scheduling Coordinator Energy Trades.~~

(a) A Scheduling Coordinator that chooses to make use of an Existing Contract must submit a Balanced Schedule that identifies the Source and Sink. The Source shall be at the originating point of the Existing Contract right and the Sink shall be at the destination point of the Existing Contract right.

(b) A Scheduling Coordinator that chooses to make use of a Point-to-Point Firm Transmission Right priority must identify a Balanced Schedule in which the Source shall be at the originating point of the FTR and the S~~s~~ink shall be at the destination point of the FTR.

(c) A bi-lateral or self-committed schedule may be expressed as a Balanced Schedule.

SP 3.1.2 Preferred Schedules

The Preferred Schedule is the initial Schedule submitted by a SC in the Day-Ahead Market or Hour-Ahead Market~~.~~. ~~A Preferred Schedule shall be a Balanced Schedule submitted to the ISO by each SC on a daily and/or hourly basis.~~

SP 3.1.3 Seven-Day Advance Schedules

SCs may submit ~~Balanced~~ Schedules or bids for up to seven (7) Trading Days at a time, representing the SC'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 SC, a Schedule submitted in advance of this deadline for submission will become the SC'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. ~~As part of the scheduling and validation process, the ISO will calculate and publish, via WEnet, the GMMs applicable to the Day-Ahead and Hour-Ahead Markets eight (8) days ahead of the Trading Day to which they relate, as described in SP 4.~~

SP 3.1.4 ~~Suggested Adjusted Schedules~~[Not Used]

~~If the sum of SCs' Preferred Schedules would cause Congestion across any Inter-Zonal Interface, the ISO shall issue Suggested Adjusted Schedules to all SCs in the Day-Ahead Market only. These Suggested Adjusted Schedules will not apply to uses of transmission owned by non-participating transmission owners 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. The ISO will publish as public~~

~~information, via the WEnet, estimated Usage.Charges for Energy transfers between Zones.~~

SP 3.1.5 **~~Revised Schedules~~[Not Used]**

~~Following receipt of a Suggested Adjusted Schedule, a SC 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.~~

SP 3.1.6 **Final Schedules**

Following the Day-Ahead and Hour-Ahead Markets, the ISO shall issue Final Schedules that reflect the outcome of those markets. A modification flag, set by the ISO, will indicate whether the ISO has modified the Preferred Schedule as a result of conducting the Day-Ahead or Hour-Ahead Market.

~~If the ISO notifies a SC that there will be no Congestion on the ISO Controlled Grid based on the Preferred Schedules submitted by all~~

~~SCs, the Preferred Schedule shall become that SC's Final Schedule. If the ISO has adjusted the SC's Preferred Schedule to match Inter-Scheduling Coordinator Energy Trades then the adjusted Preferred Schedule shall become that SC's Final Schedule. If the ISO notifies a SC that there will be no Congestion on the ISO Controlled Grid based on the Revised Schedules submitted by all SCs, the Revised Schedule shall become that SC's Final Schedule. If the ISO has adjusted the SC's Revised Schedule to match Inter-Scheduling Coordinator Energy Trades then the adjusted Revised Schedule shall become that SC'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 SCs 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 SCs.~~

SP 3.2 Day-Ahead Market

The Day-Ahead Market is an integrated forward market for Energy, Congestion Management, Unit Commitment ~~and~~ Ancillary Services. The Day-Ahead Market produces Final Schedules ~~operates individually~~ for each Settlement Period of the Trading Day. The Day-Ahead Market starts at 6:00 pm two days ahead of the Trading Day and ends at 1:00 pm on the day ahead of the Trading Day, at which time the ISO issues the Final Day-Ahead Schedules.

SP 3.2.1 By 6:00 pm, Two Days Ahead

By 6:00 pm two days ahead of the Trading Day (for example, by 6:00 pm on Monday for the Wednesday Trading Day), the ISO will publish, via OASIS~~WEnet~~, the following information for each Settlement Period of the Trading Day:

(a) a forecast of conditions on the ISO Controlled Grid, including known transmission line and other transmission facility Outages for up to the next 45 days;

(b) [Not Used]~~a forecast of Generation Meter Multipliers (GMMs), as developed in accordance with SP 4, at each Generator location and Scheduling Point;~~

(c) advisory ~~forecast of system~~ Demand Forecasts for thes ~~by~~ system and for each UDC and Load Zone~~Zone~~;

(d) ~~an estimate of the~~expected Ancillary Services requirements for the ISO Control Area for each Ancillary Service by Ancillary Service Region(see the ASRP for the details on these requirements);

(e) a forecast of Loop Flows over interfaces with other Control Areas;

(f) a forecast of the potential for Congestion conditions;

(g) a forecast of total and Available Tr~~ansmissionansfer~~ Capacity over certain ~~rated~~ transmission paths ~~and Inter-Zonal Interfaces~~;

(h) a description of any temporary adjustments to Ancillary Service standards that the ISO has determined by that time to make, in accordance with Section 2.5.2.2.

SP 3.2.1.1 By Two Hours Before ~~Close of~~ the Deadline for Submitting Initial Preferred Schedules for the ~~PX~~ Day-Ahead Market, One Day Ahead

By two hours before the ~~close of the~~deadline for submitting Initial Preferred Schedules for the ~~PX~~ Day-Ahead Market on the day ahead of the Trading Day, the ISO will notify SCs of the Energy Requirements from any Reliability Must-Run Units which the ISO requires to run in the Trading Day, except in those instances where a Reliability Must-Run Unit requires more than one day's notice, in which case the ISO may notify the applicable SC more than one day in advance of the Trading Day in accordance with Section 31.2.2 of this Tariff.~~;~~

SP 3.2.1.2 By One Hour ~~Before Close~~After Receipt of the ~~PX Day-Ahead Market~~RMR Dispatch Notice, One Day Ahead

By one hour ~~before the close~~after receipt of the ~~PX Day-Ahead Market~~RMR Dispatch Notice on the day prior to the Trading Day, SCs that have been notified that a Reliability Must-Run Unit is required to run in the Trading Day will inform the ISO, with regard to each hour for which the ISO has provided such notice, whether the RMR Owner will take payment from the market or under the RMR Contract in accordance with 31.2.2 of this Tariff.~~.~~

SP 3.2.2 By 6:00 am, One Day Ahead

By 6:00 am on the day ahead of the Trading Day (for example, by 6:00 am on Tuesday for the Wednesday Trading Day), the following information flows for each Settlement Period of the Trading Day will be required to take place:

(a) ~~SCs will provide, via WEnet, the ISO with forecasts of their Direct Access Demand by UDC Service Area ;~~

(b) the ISO will publish, via ~~WEnet~~OASIS, an updated ~~forecast of system~~ Demand Forecasts for the system and for each UDC and Load Zone~~s~~ and of the Ancillary Services requirements for the ISO Control Area for each Ancillary Service and by Ancillary Service Region; and

(c) the ISO will validate (in accordance with the SBP) the information submitted above by SCs and UDCs.

(d) Forecasted total and Available Transmission Capacity for commercially significant WECC rated transmission paths internal to the ISO Control Area and External Control Areas.

(e) Load Distribution Factors (LDFs) for trading hubs and Load Aggregation Points.

(f) Power Transfer Distribution Factors (PTDFs) for the state of the network as forecasted fo rthe Trading Day.

(g) A description of any temporary adjustments to Ancillary Service standards that the ISO has determined by that time to make, in accordance with Section 2.5.2.2.

~~**SP 3.2.3 By 6:30 am, One Day Ahead**~~

~~By 6:30 am on the day ahead of the Trading Day (for example, by 6:30 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day: the ISO will provide to UDCs, via WEnet, the sum of the SCs' Direct Access Demand forecasts by UDC Service Area; and~~

SP 3.2.4 By 8:00 am, One Day Ahead

By 8:00 am on the day ahead of the Trading Day (for example, by 8:00 am on Tuesday for the Wednesday Trading Day), and for each Settlement Period of that Trading Day, Firm Transmission Rights owners will notify the ISO, via the Secondary Registration System or other means established by the ISO, of any transaction of Firm Transmission Rights and of any changes in SCs' rights to schedule the use of Firm Transmission Rights ~~at particular Inter-Zonal Interfaces.~~

SP 3.2.5 By 8:30 am, One Day Ahead

By 8:30 am on the day ahead of the Trading Day (for example, by 8:30 am on Tuesday for the Wednesday Trading Day), and for each Settlement Period of that Trading Day, Participating Transmission Owners will notify the ISO, via e-mail of an electronic spreadsheet or other means established by the ISO, of the amounts of transmission capacity to reserve for its transmission service customers under Existing Contracts ~~at particular Inter-Zonal Interfaces~~. Upon receiving this information, the ISO will determine if the Existing Contracts capacity reservations are simultaneously feasible. By 9:00 a.m., the ISO shall calculate and publish the simultaneously-feasible Existing Contracts capacity reservations.~~Upon receiving this information, the ISO will, by 9:00 am, calculate the Firm Transmission Rights available on each Inter-Zonal Interface after taking into account transfer capabilities and Existing Contract transmission capacity reservations, and then publish adjusted scheduling rights for SCs scheduling the use of Firm Transmission Rights and Existing Contract rights.~~ After publishing the adjusted scheduling rights for Existing Contract rights and Firm Transmission Rights, SCs may submit contract usage templates (in accordance with the SBP) for validation by the ISO prior to the ISO's deadline for receiving Preferred Day-Ahead Schedules.

SP 3.2.6 By 10:00 am, One Day Ahead

SP 3.2.6.1 Actions by SCs and the ISO

By 10:00 am on the day ahead of the Trading Day (for example, by 10:00 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day (see SP 3.2.6.2 for information on the pre-validation performed at ten (10) minutes prior to the 10:00 am deadline):

(a) SCs will submit their Preferred Day-Ahead Schedules to the ISO in accordance with the SBP;

(b) SCs will submit~~, as part of their Preferred Day-Ahead Schedules,~~ their Energy ~~Adjustment~~ Bids~~,~~ and Start-up and Minimum Load costs if any, to the ISO in accordance with the SBP;

(c) SCs will submit their Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;

(d) SCs will submit their schedules for self-provided Ancillary Services, if any, to the ISO in accordance with the SBP and SP 9;

(e) the ISO will validate (in accordance with the SBP) all SC submitted Preferred Day-Ahead Schedules and Energy bids ~~for Energy and Adjustment Bids and may assist SCs to resolve mismatches in scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with the procedure described in SP 3.2.6.4;~~

(f) the ISO will validate (in accordance with the SBP) all SC submitted schedules for self-provided Ancillary Services, Inter-

Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which were part of their Preferred Day-Ahead Schedules;

(g) the ISO will validate (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights; and

(h) the ISO will validate that all SC submitted Preferred Day Ahead Schedules are compatible with the RMR requirements of which SCs were notified for that Trading Day and with the SCs' elected options for delivering the required Energy;

~~(i) the ISO will start the first iteration of Inter-Zonal Congestion Management process as described in SP 10; and~~

~~(j) the ISO will start the Ancillary Services bid evaluation process as described in SP 9;~~

SP 3.2.6.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Preferred Day-Ahead Schedules, ~~Adjustment~~Energy Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in the SBP. The purpose of this is to allow the SCs, particularly those involved in the Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of each SC's pre-validation to that SC. via WEnet.

SP 3.2.6.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for all Settlement Periods of the relevant Trading Day. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as ~~new firm u~~New Firm Uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist SCs to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades contained in their Preferred Schedules in accordance with SP 3.2.6.4. Except with respect to contract usage templates (for which SCs can check whether or not their submittal will pass the ISO's validation checks between 9:00 am and 10:00 am), SCs may check at any time prior to 10:00 am whether or not their submittal will pass the ISO's validation checks at 10:00 am. It is the responsibility of the SCs to perform such checks since Preferred

Day-Ahead Schedules, ~~Adjustment~~Energy Bids, Schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 10:00 am. ~~for the Day-Ahead Market, except that, during the initial period of ISO operations, the ISO will allow resubmission of Preferred Schedules which have mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades.~~ The ISO will immediately communicate the results of each SC's 10:00 am validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing Transmission Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the ETC rights will be considered a New Firm Use (NFU) and will be exposed to Congestion and Energy charges.

SP 3.2.6.4 Inter-Scheduling Coordinator Energy Trades - Mismatches

During the initial period of ISO operations, if the ISO detects a mismatch in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades, the ISO will promptly notify both the receiving and sending SCs that a mismatch exists. ~~and will specify the time, which will allow them approximately one half-hour, by which they may submit modified Schedules which resolve the mismatch~~. If the SCs are unable to resolve the mismatch ~~as to quantities in the allotted time~~ and provided there is no dispute as to whether the trade occurred or over its location, then the ISO may reconcile mismatches after the close of the market but prior to Settlement. ~~adjust the SCs' Schedules in accordance with the following procedure:~~

~~(a) The ISO will determine which Schedule contains the higher scheduled quantity of Energy for the Inter-Scheduling Coordinator Energy Trade and will reduce it so that it is equal to the lower scheduled quantity. However, if the Schedule specifying the higher scheduled quantity of Energy contains only Inter-Scheduling Coordinator Energy Trades, the ISO will increase the Schedule specifying the lower quantity of Energy so that it is equal to the higher scheduled quantity of Energy.~~

(~~b~~a) If there is a dispute between the SCs as to whether the trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears.

(~~c~~b) ~~As a consequence of the adjustments under (a) or (b) above, the SCs whose Schedules have been adjusted will no longer have a Balanced Schedule. The ISO will adjust their resources based on the following priority: Demands, exports, imports, Generation, and other Inter-Scheduling Coordinator Energy Trades.~~

(c~~d~~) The adjustments to each SC's portfolio will be based on the ~~Adjustment~~Energy Bids provided by the SC.

(~~e~~d) The ISO will notify each SC whose Schedule has been adjusted as to the adjustment in its Schedule.

SP 3.2.7 **[Not Used]** ~~**By 11:00 am, One Day Ahead**~~

~~By 11:00 am on the day ahead of the Trading Day (for example, by 11:00 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day:~~

~~(a) the ISO will complete the first iteration of the Inter-Zonal Congestion Management process described in SP 10 (if Inter-Zonal Congestion does not exist in any Settlement Period of the Trading Day, the scheduling process will continue with the steps at SP 3.2.9);~~

~~(b) the ISO will provide, via WEnet, Suggested Adjusted Day-Ahead Schedules for Energy to all SCs which submitted Preferred Day-Ahead Schedules at 10:00 am, including the SCs which it is proposed should, as a result of Inter-Zonal Congestion Management, have their Preferred Day-Ahead Schedules modified;~~

~~(c) the ISO will publish on WEnet the estimated Day-Ahead Usage Charge rate (in $/MWh of scheduled flow) for Energy transfers between Zones; and~~

~~(d) the ISO will provide, via WEnet, along with the Suggested Adjusted Day-Ahead Schedules, schedules for Ancillary Services to the SCs which either:~~

~~(i) submitted Ancillary Services bids and which, as a result, are proposed to supply Ancillary Services; or~~

~~(ii) submitted schedules to self-provide Ancillary Services and which schedules have been accepted by the ISO.~~

~~(e) the ISO will provide, via WEnet, the available contract capacity template associated with the SC's scheduled use of any Existing Contract rights or Firm Transmission Rights. If any derate of an Inter-Zonal Interface has occurred, the ISO will provide, via WEnet, the invalidated usage information template.~~

SP 3.2.8 **[Not Used]** ~~**By 12:00 Noon, Day Ahead**~~

~~By 12:00 noon on the day ahead of the Trading Day (for example, by 12:00 noon on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day (except where Inter-Zonal Congestion does not exist, in which case, the scheduling process will omit this step):~~

SP 3.2.8.1 **[Not Used]** ~~**Actions by SCs and the ISO**~~

~~(a) SCs will submit Revised Day-Ahead Schedules to the ISO, in response to the ISO's Suggested Adjusted Day-Ahead Schedules, in accordance with the SBP;~~

~~(b) SCs will submit, as part of their Revised Day-Ahead Schedules, revised Adjustment Bids (allowing the range of~~

~~usage to change, but not the prices), if any, to the ISO in accordance with the SBP;~~

~~(c) SCs will submit revised Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;~~

~~(d) SCs will submit their schedules for self-provided Ancillary Services, if any, to the ISO in accordance with the SBP and SP 9;~~

~~(e) the ISO will validate (in accordance with the SBP) all SC submitted Revised Day-Ahead Schedules for Energy and Adjustment Bids and may assist SCs to resolve mismatches in scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with the same procedure described in SP 3.2.8.4;~~

~~(f) the ISO will validate (in accordance with the SBP) all SC submitted schedules for self-provided Ancillary Services and Ancillary Services bids which were part of their Revised Day-Ahead Schedules;~~

~~(g) the ISO will validate (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights.~~

~~(h) the ISO will start the second (and final) iteration of the Inter-Zonal Congestion Management process as described in SP 10;~~

~~(i) the ISO will start the second (and final) iteration of the Ancillary Services bid evaluation process as described in SP 9; and~~

~~(j) the ISO will use the SC's Preferred Day-Ahead Schedule in the event the SC does not submit a Revised Day-Ahead Schedule. If a SC desires to revise only part of its Preferred Day-Ahead Schedule, those portions of the Revised Day-Ahead Schedule must be submitted, including both the removal of any resources in the Preferred Day-Ahead Schedule which are not to be included in the Revised Day-Ahead Schedule and the addition of any resources that were not included in the Preferred Day-Ahead Schedule but that are to be included in the Revised Day-Ahead Schedule. A SC's failure to remove such resources will cause the Revised Schedule to be unbalanced, and rejected as such in the ISO's validation process.~~

SP 3.2.8.2 [Not Used] ~~Pre-validation~~

~~At 10 minutes prior to the deadline for submittal of the Revised Day-Ahead Schedules, Adjustment Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in the SBP. The purpose of this is to allow the SCs, particularly those involved in Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately~~

~~communicate the results of the pre-validation of each SC's submittal to that SC via WEnet.~~

SP 3.2.8.3 **[Not Used]** ~~**Invalidation**~~

~~Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for all Settlement Periods of the relevant Trading Day. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist SCs to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with 3.2.8.4. Except with respect to contract usage templates, SCs may check at any time prior to 12:00 noon whether or not their submittal will pass the ISO's validation checks (which are undertaken at 12:00 noon). It is the responsibility of the SCs to perform such checks since Revised Day-Ahead Schedules, Adjustment Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 12:00 noon for the Day-Ahead Market, except that during the initial period of operations, the ISO will allow resubmission of Schedules to resolve mismatches in the scheduled quantities and locations for Inter-Scheduling Coordinator Energy Trades. The ISO will immediately communicate the results of each SC's 12:00 noon validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing Transmission Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the ETC rights will be considered a New Firm Use (NFU) and will be exposed to Congestion charges.~~

SP 3.2.8.4 **[Not Used]** ~~**Inter-Scheduling Coordinator Energy Trades - Mismatches**~~

~~During the initial period of ISO operations, if the ISO detects a mismatch in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades, the ISO will promptly notify both the receiving and sending SCs that a mismatch exists and will specify the time, which will allow them approximately one half-hour, by which they may submit modified Schedules which resolve the mismatch. If the SCs are unable to resolve the mismatch as to quantities in the allotted time and provided there is no dispute as to whether the trade occurred or over its location, the ISO may adjust the SCs' Schedules in accordance with the following procedure:~~

~~(a) The ISO will determine which Schedule contains the higher scheduled quantity of Energy for the Inter-Scheduling~~

~~Coordinator Energy Trade and will reduce it so that it is equal to the lower scheduled quantity. However, if the Schedule specifying the higher scheduled quantity of Energy contains only Inter-Scheduling Coordinator Energy Trades, the ISO will increase the Schedule specifying the lower quantity of Energy so that it is equal to the higher scheduled quantity of Energy.~~

~~(b) If there is a dispute between the SCs as to whether the trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears.~~

~~(c) As a consequence of the adjustments under (a) or (b) above, the SCs whose Schedules have been adjusted will no longer have a Balanced Schedule. The ISO will adjust their resources based on the following priority: Demands, exports, imports, Generation, and other Inter-Scheduling Coordinator Energy Trades.~~

~~(d) The adjustments to each SC's portfolio will be based on the Adjustment Bids provided by the SC.~~

~~(e) The ISO will notify each SC whose Schedule has been adjusted as to the adjustment in its Schedule~~.

SP 3.2.9 By 1:00 pm, Day Ahead

By 1:00 pm on the day ahead of the Trading Day (for example, by 1:00 pm on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day:

(a) the ISO will complete <u>the operation of the integrated Day-Ahead Market</u>~~the second iteration, if necessary, of the Inter-Zonal Congestion Management process described in SP 10~~;

(b) the ISO will provide, via WEnet, Final Day-Ahead Schedules to all SCs<u>.</u> ~~which, depending on the existence of Inter-Zonal Congestion, could be:~~

~~(i) the Preferred Day-Ahead Schedules (when no Congestion was found at 11:00 am and no mismatched Inter-Scheduling Coordinator Energy Trades);~~

~~(ii) the Revised Day-Ahead Schedules (when no Congestion was found at 1:00 pm and no mismatched Inter-Scheduling Coordinator Energy Trades);~~

~~(iii) modified Revised Day-Ahead Schedules for those SCs which had their Revised Day-Ahead Schedules for Energy modified for Inter-Zonal Congestion or mismatches in Inter-Scheduling Coordinator Energy Trades; or~~

~~(iv) modified Preferred Day-Ahead Schedules<u>,</u> for those SCs which had their Preferred Schedule for Energy modified for Inter-Scheduling Coordinator Energy Trade mismatches;~~

(c) the ISO will publish on OASIS~~WEnet~~ the hourly Day-Ahead ~~Usage Charge~~LMPs~~ rate~~ (in $/MWh of scheduled flow) for Energy.~~ transfer between Zones, if any;~~,

(d) the ISO will provide, via WEnet, as part of the Final Day-Ahead Schedules, schedules for Ancillary Services to the SCs which either:

(i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or

(ii) submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO; and

(iii) specified Inter-Scheduling Coordinator Ancillary Service Trades which have been validated by the ISO; and

(e) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual SC intertie schedules will be examined. If the other Control Area's records are determined to be correct, the ISO will notify the affected SC. If the other Control Area Operator's records are in error, no changes will be required by the ISO or affected SCs. The affected SC is required to correct its schedule in the Hour-Ahead Market.

SP 3.2.10 Betweeen~~y~~ 1:30 pm and 3:00 pm, Day Ahead

By 1:30 pm on the day ahead of the Trading Day (for example, by 1:30 pm on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day the ISO will publish, via OASIS~~WEnet~~,an updated forecast of system Demands.

The ISO shall run the Residual Unit Commitment Process to determine what if any additional Generators, System Resources, Dispatchable Loads and/or System Units need to be committed to meet the ISO Demand Forecast. The Residual Unit Commitment process will make use of all available bids in accordance with Section 5.12.2.

~~**SP 3.2.10(b) By 3:00 pm, Day Ahead**~~

At 3:00 pm, t~~T~~he ISO shall transmit, via WEnet, notice to Scheduling Coordinators for all additional Generators, System Resources, Dispatchable Loads and/or System Units that are selected as a result of the Residual Unit Commitment Process. The ISO shall also transmit the quantity of committed capacity on each resource committed as a result of the Residual Unit Commitment Process.

SP 3.2.11 **Between 1:00 p.m. and 11~~0~~:00 p.m.**

If, at any time after 1:00 p.m. and before 11~~0~~:00 p.m. of the day prior to the Trading Day, the ISO determines that it requires Ancillary Services in addition to those provided through the Final Day-Ahead Schedules issued under SP 3.2.9, it may procure such additional Ancillary Services by providing to SCs, via WEnet, amended schedules for Ancillary Services that had been bid in the Day-Ahead Market but were not previously selected in the Final Day-Ahead Schedules, and have not been previously withdrawn. The ISO shall select such Ancillary Services ~~in price merit order (and~~ in the relevant Ancillary Service Region ~~zone~~ if the ISO is procuring Ancillary Services on a regional~~zonal~~ basis~~)~~. Such amended schedules shall be provided to the SCs no later than 11~~0~~:00 p.m. of the day prior to the Trading Day.

SP 3.3 Hour-Ahead Market

(a) The Hour-Ahead Market is a “deviations” market in that it represents changes from the Day-Ahead Market commitments already made for each Settlement Period in the Trading Day. The SCs do not schedule these deviations. Instead, these deviations are calculated by the ISO as the difference between the Final Hour-Ahead Schedules (reflecting updated forecasts of Generation, Demand, external imports/exports and Inter-Scheduling Coordinator Energy Trades) and the Final Day-Ahead Schedules. If a SC does not submit a valid Preferred Hour-Ahead Schedule, its Final Day-Ahead Schedule will be deemed to be its Preferred Hour-Ahead Schedule.

(b) The Hour-Ahead Markets for each Settlement Period of each Trading Day open when the Day-Ahead Market commitments are made for the same Trading Day. Hour-Ahead Market commitments are made one hour ahead of the start of the applicable Settlement Period, at which time the ISO issues the Final Hour-Ahead Schedules. There is an option in the bid submittal process for a SC to submit a Schedule or bid for one Settlement Period of the Trading Day or a set of Schedules and bids for all Settlement Periods of the Trading Day (but only between 1:00 pm and 11~~2~~:00 pm~~midnight~~ the day before).

(c) For each Hour-Ahead Market of the Trading Day the ISO's validation of SCs' contract usage templates, associated with Existing Contract rights or Firm Transmission Rights, will be performed. If a derate of a transmission Pathway ~~Inter-Zonal Interface~~ has occurred which affects an SC's Final Day-Ahead Schedule or Ancillary Service commitments, the ISO will notify the SC, via the WEnet, of its available contract capacity. Additionally, the ISO will validate SCs' scheduled usage against SCs' contract usage templates and notify SCs of any invalidated usage. Such validations and notifications associated with contract usage, available contract capacities and invalidated contract usage will occur during the two hours prior to the ISO's deadline for receiving Preferred Hour-Ahead Schedules.

SP 3.3.1 By One~~Two~~ Hour~~s~~ Ahead

By one~~two~~ hour~~s~~ ahead of the Settlement Period (for example, by ~~10~~11:00 am for the Settlement Period starting at 12:00 noon [or hour ending 1300]) and with respect to that Settlement Period:

SP 3.3.1.1 Actions by SCs and the ISO

(a) SCs will submit their Preferred Hour-Ahead Schedules to the ISO in accordance with the SBP;

(b) SCs will submit, as part of their Preferred Hour-Ahead Schedules, their ~~Adjustment~~Energy Bids, if any, to the ISO in accordance with the SBP;

(c) SCs will submit their Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;

(d) SCs will submit their Schedules for self-provided Ancillary Services and Inter-Scheduling Coordinator Ancillary Service Trades, ~~-~~if any, to the ISO in accordance with the SBP and SP 9;

(e) the ISO will validate (in accordance with the SBP) all SC submitted Preferred Hour-Ahead Schedules for Energy and ~~Adjustment~~Energy Bids;

(f) SCs will submit contract usage templates for scheduled uses of Existing Contract Rights and Firm Transmission Rights in accordance with the Hour-Ahead Market schedule, including usage template changes needed in response to line derations;

(g) the ISO will validate (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights;

(h) the ISO will validate (in accordance with the SBP) all SC submitted Schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which were part of their Preferred Hour-Ahead Schedules;

~~(i) the ISO will start the Inter-Zonal Congestion Management process as described in SP 10;~~

~~(j) the ISO will start the Ancillary Services bid evaluation process as described in SP 9; and~~

(i~~k~~) the ISO will validate that all SC submitted Preferred Hour-Ahead Schedules are compatible with the RMR requirements of which SCs were notified for that Trading Day and with the SCs' elected options for delivering the required Energy**.**

SP 3.3.1.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Preferred Hour-Ahead Schedules, ~~Adjustment~~Energy Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in the SBP. The purpose of this is to allow the SCs, particularly those involved in the Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of the pre-validation of each SC's submittal to that SC via WEnet.

SP 3.3.1.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal results in rejection of the submittal. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as N~~n~~ew F~~f~~irm U~~u~~ses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. SCs may check at any time prior to two hours ahead of the relevant Settlement Period whether or not their submittals will pass the ISO's validation checks (which are undertaken at one~~two~~ hour~~s~~ ahead of the Settlement Period). It is the responsibility of SCs to perform such checks since Preferred Hour-Ahead Schedules, ~~Adjustment~~Energy Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades and Ancillary Services bids which are invalidated cannot be resubmitted for the Hour-Ahead Market after one~~two~~ hour~~s~~ ahead of the relevant Settlement Period. The ISO will immediately communicate the results of each SC's one~~two~~ hour ahead validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing ~~Transmission~~ Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the ETC rights will be considered a New Firm Use (NFU) and will be exposed to Congestion charges.

SP 3.3.2 By ~~One Hour~~45 minutes Ahead

By 45 minutes ~~one hour~~ ahead of the Settlement Period (for example, by 11:15~~00~~ am for the Settlement Period starting at 12:00 noon [or hour ending 1300]) and in respect of that Settlement Period:

(a) The ISO will use the SC's Final Day-Ahead Schedule, without any Day-Ahead ~~Adjustment~~Energy Bids or Day-Ahead Ancillary Service bids, in the event the SC's Preferred Hour-Ahead Schedule fails validation. If a SC desires to submit an Hour-Ahead Schedule that is different than its Final Day-Ahead Schedule the SC must submit the Hour-Ahead Schedule including the addition or removal of any resources (i.e., for those resources to be removed, a zero value for the hourly MW quantity) in its Final Day-Ahead Schedule that are to be added, or that are not to be included, in the Hour-Ahead Schedule. SCs may only remove resources with the ISO's approval as set forth in Section 2.3.1.2.1. ~~A SC's failure to add or remove such resources will cause the Hour-Ahead Schedule to be unbalanced, and rejected as such in the ISO's validation process.~~

(b) the ISO will complete, if necessary, the ~~Inter-Zonal~~ Congestion Management process described in SP 10;

(c) the ISO will provide, via WEnet, Final Hour-Ahead Schedules for Energy to the ISO's real time dispatchers for use under the DP and to all SCs which~~, depending on the existence of Inter-Zonal Congestion,~~ could be:

(i) ~~the Preferred Hour-Ahead Schedules (when no Congestion was found at one hour ahead); or~~

(~~i~~i) modified Preferred Hour-Ahead Schedules for those SCs which had their Preferred Hour-Ahead Schedules for Energy modified .~~for Inter-Zonal Congestion; and~~

(d) the ISO will publish on OASIS~~WEnet~~ the Hour-Ahead ~~Usage Charge rate~~ LMPs (in $/MWh ~~of scheduled flow)~~ ~~for Energy transfers between Zones, if any;~~

(e) the ISO will provide, via WEnet, as part of the Final Hour-Ahead Schedules, schedules for Ancillary Services to the ISO's real time dispatchers for use under the DP and to the SCs which either:

(i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or

(ii) specified Inter-Scheduling Coordinator Ancillary Service Trades, or submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO; ~~and~~

(f) each SC will provide the ISO, via a form and by means of communication specified by the ISO, resource specific information for all Generating Units and Dispatchable Loads~~Curtailable Demands~~ constituting its System Unit, if any, scheduled or bid into the ISO's Day-Ahead Market and/or Hour-Ahead Market for Ancillary Services;~~.~~

(g) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual SC intertie schedules will be examined. If the other Control Area operator's records were in error, no changes will be required by the ISO or SCs. If the other Control Area operator's records are determined to be correct, the ISO will notify the affected SC. The ISO will manually adjust the affected SC's schedule to conform with the other Control Area operator's net schedule, in real time, and the affected SC will be responsible for managing any resulting Energy imbalance.

SP 3.3.3 Prior to t~~T~~he B~~b~~eginning of The Settlement Period.

Prior to the beginning of the Settlement Period, the ISO shall determine all pre-dispatch requirements for the upcoming Settlement Period as determined in accordance with 31.4.2. Such pre-dispatches shall be communicated to the responsible Scheduling Coordinators .

SP 4 TRANSMISSION SYSTEM LOSS MANAGEMENT

SP 4.1 Overview

(a) ~~A SC must ensure that each Schedule it submits to the ISO is a Balanced Schedule in which aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades equals the aggregate Forecast Demand and external exports~~. The ISO will,reflect the marginal losses in the LMPs calculated by SCUC and SCED.~~ for this purpose, specify GMMs for each Energy supply source~~

~~(Generating Units and external imports at Scheduling Points) to~~ to account for the Energy lost in transmitting power from Generating Units and/or Scheduling Points to Load. Inter-Scheduling Coordinator Energy Trades will not be subject to such adjustments~~, beyond the impact of GMMs on the respective SC's Generation and external imports~~. ~~The ISO will, in accordance with this SP 4, derive a location specific GMM for each Generating Unit and external import on the ISO Controlled Grid.~~

~~(b) At all times, the ISO will make available GMMs for the seven Trading Days starting with the Trading Day after the next Trading Day. Each day, at 6:00 pm, the ISO will calculate and publish, via WEnet, the GMMs applicable to the Day-Ahead Markets and the Hour-Ahead Markets for the eighth (8^{th}) Trading Day forward. In other words, if the current Trading Day is day 0, the ISO will publish at 6:00 pm today, via WEnet, the GMMs for Trading Days 2 through 8. On Trading Day 1, at 6:00 pm, the ISO will drop the GMMs for Trading Day 1 and add the newly calculated GMMs for Trading Day 9, with the GMMs for Trading Days 3 through 8 remaining the same.~~

SP 4.2 [Not Used] ~~Generator Meter Multipliers (GMMs)~~

~~SP 4.2.1 Derivation of GMMs~~

~~(a) The ISO will utilize the Power Flow Model to determine the GMMs which will be used to allocate, to each Generating Unit and external import, scheduled and Ex Post Transmission Losses.~~

~~(b) For each Settlement Period, the GMMs will be first calculated before SCs submit Day-Ahead Preferred Schedules. Prior to the time when SCs are required to submit their Day-Ahead Preferred Schedules, the ISO will forecast the total Control Area Demand. This forecast, along with the ISO forecast of Generation and Demand patterns throughout the ISO Control Area, will be used to develop estimated GMMs for each Generating Unit and each external import. The ISO will calculate and publish (in accordance with SP 3.2.1) GMMs for each Settlement Period to reflect different expected Generation and Demand patterns and expected operations and maintenance requirements, such as line Outages, which could affect Transmission Loss determination and allocation.~~

~~(c) The ISO will utilize the real time Power Flow Model to calculate Ex Post GMMs to allocate Ex Post Transmission Losses to each Generating Unit and each external import. This run of the Power Flow Model will use metered Generation and Demand. Any difference between scheduled and Ex Post Transmission Losses will be considered as an Imbalance Energy deviation and will be purchased or sold in the Real Time Market at the BEEP Interval Ex Post Price.~~

~~**SP 4.2.2 Methodology for Calculating Transmission Losses**~~

~~(a) The ISO Power Flow Model will be utilized to calculate the effects on total Transmission Losses at each Generating Unit and Scheduling Point by calculating the sensitivity of injecting Energy at each Generating Unit bus or Scheduling Point to serve an increment of Demand distributed proportionately throughout the ISO Control Area. This will produce the Full Marginal Loss Rate at each Generating Unit and Scheduling Point.~~

~~(b) The ISO will then determine the ratio of expected Transmission Losses to the total Transmission Losses that would be collected if Full Marginal Loss Rates were utilized to determine Transmission Losses. This ratio is referred to as the Loss Scale Factor.~~

~~(c) The ISO will then multiply the Loss Scale Factor by the Full Marginal Loss Rate at each Generating Unit or Scheduling Point to determine each Generating Unit's or external import's Scaled Marginal Loss Rate. The GMM is calculated by subtracting the Scaled Marginal Loss Rate from unity.~~

~~**SP 4.3 Existing Contracts and Transmission Losses**~~

~~Certain Existing Contracts may have requirements for Transmission Loss accountability which differ from the provisions of this SP 4. Each PTO will be responsible for recovering any deficits or crediting any surpluses, associated with differences in assignment of Transmission Loss requirements, through its bilateral arrangements or its Transmission Owner's Tariff. The ISO will not undertake the settlement or billing of any such differences under any Existing Contract.~~

SP 5 RELIABILITY MUST-RUN GENERATION

SP 5.1 Procurement of Reliability Must-Run Generation by the ISO

SP 5.1.1 Annual Reliability Must-Run Forecast - Technical Evaluation

On an annual 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.

SP 5.1.2 Annual Reliability Must-Run Forecast - Technical Studies

The ISO will perform off-line technical studies, adopt existing procedures developed by PTOs and/or develop new operating procedures to identify the Reliability Must-Run requirements for various levels of system Demand.

SP 5.2 Designation of Generating Unit as Reliability Must-Run

The ISO will have the right at any time based upon ISO Controlled Grid technical analyses and studies to designate or disqualify a Generating Unit as a Reliability Must-Run Unit.

SP 5.3 Scheduling of Reliability Must-Run Generation

The ISO will notify SCs of any Reliability Must-Run Units which the ISO requires to run during a Trading Day no later than two hours before the deadline for submitting Day-Ahead Preferred Schedules~~close of the PX Day-Ahead Market~~ for that Trading Day, as described in SP 3.2.1.1

SP 5.4 [UNUSED]

SP 6 [UNUSED]

SP 7 MANAGEMENT OF EXISTING CONTRACTS FOR TRANSMISSION SERVICE

SP 7.1 Obligations of Participating Transmission Owners and Scheduling Coordinators

SP 7.1.1 Participating Transmission Owners

Prior to the ISO accepting Schedules which include the use of Existing Rights, the Responsible PTO (as defined in the SBP) must have provided the ISO with the information required in the Transmission Control Agreement and the SBP, including transmission rights/curtailment instructions ("instructions") supplied in a form and by means of communication specified by the ISO.

SP 7.1.2 Scheduling Coordinators

The ISO will accept valid Schedules from a Responsible PTO that is the SC for the Existing Contract rights holders, or from Existing Contract rights holders that are SCs, or that are represented by a SC other than the Responsible PTO. Schedules submitted by SCs to the ISO which include the use of Existing Rights must be submitted in accordance with the SBP and this SP.

SP 7.2 Allocation of Forecasted Total Transfer Capabilities

SP 7.2.1 Categories of Transmission Capacity

As used in this SP, references to N~~n~~ew F~~f~~irm U~~u~~ses shall mean any use of ISO transmission service, except for uses associated with Existing Rights. Prior to the start of the Day-Ahead scheduling process, for each ~~Inter-Zonal~~ significant WSCC--rated path inside the ISO C~~c~~ontrol A~~a~~rea or i~~I~~nterface with an external Control Area, the ISO will allocate the forecasted total transfer capability of the i~~I~~nterface to three~~four~~ categories. This allocation will represent the ISO's best estimates at the time, and is not intended to affect any rights provided under Existing Contracts, except as provided in SP 7.4. The ISO's forecast of total transfer capability for each ~~Inter-Zonal~~s iInterface will depend on prevailing conditions for the relevant Trading Day, including, but not limited to, the effects of parallel path (unscheduled) flows and/or other limiting operational conditions. This information will be posted on OASIS~~WEnet~~ by the ISO in accordance with SP 3.2.1. In accordance with Section 2.4.4.5.1.4 of the ISO Tariff, the three~~four~~ categories are as follows:

(a) transmission capacity that must be reserved for firm Existing Rights;

(b) transmission capacity that may be allocated for use as ISO transmission service (i.e., "N~~n~~ew F~~f~~irm U~~u~~ses");

~~(c) transmission capacity that may be allocated by the ISO for conditional firm Existing Rights; and~~

(c~~d~~) transmission capacity that may remain for any other uses, such as non-firm Existing Rights for which the Responsible PTO has no discretion over whether or not to provide such non-firm service.

SP 7.2.2 Prioritization of Transmission Uses

The following rules are designed to enable the ISO to honor Existing Contracts in accordance with Sections 2.4.3 and 2.4.4 of the ISO Tariff. Regardless of the success of the application of such rules, it is intended that the rights under Existing Contracts will be honored as contemplated by the ISO Tariff. In each of the categories described in SP 7.2.1, the terms and conditions of service may differ among transmission contracts. These differences will be described by each Responsible PTO in the instructions submitted to the ISO in advance of the scheduling process in accordance with the SBP. In addition, Generation~~, Inter-Scheduling Coordinator Energy Trade imports~~ or ~~external~~ imports ~~in one Zone~~ must be matched by an equal magnitude of Demand, ~~Inter-Scheduling Coordinator Energy Trade exports~~ or ~~external~~ exports ~~in an adjacent Zone~~ (see SP 7.2.3 for a summary of allowable linkages). Scheduling and curtailment priorities associated with each category will be defined by SCs through the use of contract usage templates submitted as part of their Schedules as described in the SBP.

(a) Transmission capacity for Schedules will be made available to holders of firm Existing Rights in accordance with this SP and Section 9 of this Tariff and the terms and conditions of their Existing Contracts. In the event that the firm uses of these rights must be curtailed, they will be curtailed on the basis of priority expressed in contract usage templates. So as not to be curtailed before any other scheduled use of Congested ~~Inter-Zonal Interface~~ capacity, the ISO's Congestion

Management software will ~~assign~~ assign a priority to such schedules consistent with Section 31.2.3.2.~~high priced Adjustment Bids to the scheduled uses (for example, a difference of $130,000/MWh to $140,000/MWh for Demand or external exports and a difference of -$130,000/MWh to -$140,000/MWh for Generation or external imports). This range will be reserved strictly for use in association with the prioritization of firm Existing Rights to use available Inter-Zonal Interface transmission capacity. These high priced Adjustment Bids are only for the ISO's use, in the context of Congestion Management, in recognizing the various levels of priority that may exist among the scheduled uses of firm transmission service. These high priced Adjustment Bids will not affect any other rights under Existing Contracts. To the extent that the MW amount exceeds the MW amount specified in the Existing Contract, the excess scheduled amount will be treated as a new firm use of ISO transmission services as described in (b) below. Note that, in some instances, for a particular Inter-Zonal Interface, there may be multiple SCs submitting Schedules under several different Existing Contracts on behalf of several Existing Contract rights holders. In these circumstances, and to the extent the rights holders desire to coordinate the prioritization of their firm uses of the Inter-Zonal Interface, their SCs will make the arrangements among themselves ahead of the ISO's scheduling process. In the absence of a valid contract usage template associated with Existing Contract rights, the ISO will treat the scheduled use of transmission service as a "price-taker" of ISO transmission service subject to Usage Charges.~~

(b) ISO transmission service (i.e., "~~new firm u~~New Firm Uses") will be priced in accordance with the ISO Tariff. ~~Usage Charges~~LMPs associated with the ISO's Congestion Management procedures, as described in SP 10, will be based on Energy~~Adjustment~~ Bids. In the absence of an ~~Adjustment~~Energy Bid, the ISO will treat the scheduled "~~new firm u~~New Firm Use" of ISO transmission service as a P~~p~~rice T~~t~~aker paying the difference in LMPs of the Scheduling Coordinators' Sources and Sinks~~Usage Charge established by the highest valued use of transmission capacity between the relevant Zones.~~

(c) Transmission capacity will be made available to holders of conditional firm Existing Rights in a manner similar to that done prior to the ISO Operations Date; that is, allocated, as available, based on the agreed priority. The levels of priority will be expressed in the contract usage templates associated with the Schedules. To the extent that the MW amount in a schedule exceeds the MW amount specified in the contract usage template, the excess scheduled amount will be treated as a ~~new firm u~~New Firm Use of ISO transmission services as described in (b) above. Note that, in some instances, ~~for a~~

~~particular Inter-Zonal Interface,~~ there may be multiple SCs submitting Schedules under several different Existing Contracts on behalf of several Existing Contract rights holders. In these circumstances, and to the extent the rights holders desire to coordinate the prioritization of their conditional firm uses of the ~~Inter-Zonal Interface~~transmission, their SCs will make the arrangements among themselves ahead of the ISO's scheduling process. In the absence of a valid contract usage template associated with Existing Contract rights, the ISO will treat the scheduled use of transmission service as a ~~“~~P~~p~~rice-T~~t~~aker~~”~~ of ISO transmission services subject to Usage Charges.

(d) Transmission capacity will be made available to holders of non-firm Existing Rights in a manner similar to that done prior to the ISO Operations Date; that is, treated as the lowest valued use of available transmission capacity. ~~Non-firm uses of transmission capacity under Existing Contracts will be indicated in Schedules submitted by SCs as $0.00/MWh Adjustment Bids. Therefore, there will be no contract reference number associated with non-firm Existing Contract rights~~.

SP 7.2.3 Allowable Linkages

As indicated in SP 7.2.2, Generation, ~~Inter-Scheduling Coordinator Energy Trade imports~~ or external imports ~~in one Zone~~ must be matched by an equal magnitude of Demand, ~~Inter-Scheduling Coordinator Energy Trade exports~~ or external exports. ~~in the same Zone or in an adjacent Zone~~.

SP 7.3 The Day-Ahead Process

SP 7.3.1 Validation

The ISO will coordinate the scheduling of the use of Existing Rights with ~~new firm u~~New Firm Uses in the Day-Ahead process. The ISO will validate the Schedules submitted by SCs on behalf of the rights holders for conformity with the instructions previously provided by the Responsible PTO in accordance with the SBP. Invalid Schedules will be rejected and the ISO will immediately communicate the results of each SC's validation to that SC via WEnet.

SP 7.3.2 Scheduling Deadlines

Those Existing Contract rights holders who must schedule the use of their rights by the deadline for the submission of Schedules in the Day-Ahead Market must do so. After this time, the ISO will release these unused rights as available for N~~n~~ew F~~f~~irm U~~u~~ses (not subject to recall).

SP 7.3.3 Reservation of Firm Transmission Capacity

As an initial step in performing its Day-Ahead Congestion Management analysis, the ISO will determine the amount of transmission capacity that is available and subject to its Protocols by subtracting, from the total transfer capability of the ~~Inter-Zonal Interface,~~transmission system the unused portions of capacity applicable to firm Existing Rights. For purposes of Congestion Management, the total transfer capability ~~of the Inter-Zonal Interface~~ of the Pathway ~~~~is therefore adjusted downward by an amount equal to the unused portions of firm Existing Rights. By reserving these blocks of unused transmission capacity, Existing Contracts rights holders are able to schedule the use of their transmission service on the timelines provided in their Existing Contracts after the deadline of the ISO's Day-Ahead scheduling process (in other words, after 1:00 pm on the day preceding the Trading Day), but prior to the deadline of the ISO's Hour-Ahead scheduling process (in other words, one~~two~~ hour~~s~~ ahead of the Settlement Period).

SP 7.3.4 Allocation of ~~Inter-Zonal~~Pathway ~~Interface~~ Capacities

In the ISO's Congestion Management analysis of the Day-Ahead Market, for each ~~Inter-Zonal Interface:~~Pathway:

(a) if all scheduled uses of transmission service fit within the adjusted total transfer capability, all are accepted (in other words, there is no Congestion);

(b) if all scheduled uses of transmission service do not fit within the adjusted total transfer capability, scheduled uses of non-firm Existing Rights will be curtailed, pro rata, to the extent necessary. If the remaining scheduled uses of transmission service still do not fit within the adjusted total transfer capability, uses of conditional firm Existing Rights will be curtailed (based upon the levels of priority expressed in the contract usage templates for Schedules as described in SP 7.2.2 (c)) to the extent necessary;

(c) if Congestion still exists after curtailing all lower priority schedules (e.g. requesting non-firm and conditional firm uses of transmission service under Existing Contracts), the remaining transmission capacity (that is not already reserved as firm Existing Rights) is priced based upon ~~Adjustment~~Energy Bids. To the extent there are insufficient ~~Adjustment~~Energy Bids to fully mitigate the remaining Congestion, the default Usage Charge will apply and the ISO will curtail ISO transmission service (in other words, ~~new firm u~~New Firm Uses other than Firm Transmission Rights uses evaluated in the Day-Ahead process)~~, pro rata,~~ based on the effectiveness of the resource on relieving the Congestion to the extent necessary;

(d) If Congestion still exists after curtailing all ~~new firm u~~New Firm Uses (other than Firm Transmission Rights uses) in the Day-Ahead scheduling process, scheduled uses of Firm Transmission Rights are then curtailed~~, *pro rata*,~~ based on the effectiveness of the resource on relieving the Congestion to the extent necessary; and

(e) if Congestion still exists after curtailing ISO ~~new firm u~~New Firm Uses and uses of Firm Transmission Rights, scheduled uses of firm Existing Rights are then curtailed (based upon the priorities expressed in the contract usage templates associated with the Schedules as described in SP 7.2.2 (a)) to the extent necessary.

SP 7.4 The Hour-Ahead Process

SP 7.4.1 Validation

The ISO will coordinate the scheduling of the use of Existing Rights with ~~new firm u~~New Firm Uses, in the Hour-Ahead process. The ISO will validate the submitted Schedules for conformity with the instructions provided by the Responsible PTOs, in accordance with the SBP. Invalid schedules will be rejected and the ISO will immediately communicate the results of each SC's validation to that SC via WEnet.

SP 7.4.2 Scheduling Deadlines

Those rights holders who must schedule the use of their rights by the deadline for the submission of Schedules in the Hour-Ahead Market must do so. After this time, the ISO will release these unused rights as available for ~~new firm u~~New Firm Uses (not subject to recall).

SP 7.4.3 Acceptance of Firm Transmission Schedules

Before allocating any remaining transmission capacity under the following provisions of this SP 7, the ISO will accept Schedules associated with firm Existing Rights (subject to validation under SP 7.4.1), allocating transmission capacity for use by these rights holders.

SP 7.4.4 Reservation of Firm Transmission Capacity

The ISO will adjust the total transfer capabilities of ~~Inter-Zonal Interfaces~~the Pathways with respect to firm Existing Rights as it does in its Day-Ahead process described in this SP 7.3.3. Therefore, holders of Existing Rights are still able to exercise whatever scheduling flexibility they may have under their Existing Contracts after the Schedules and bids submittal deadline of the ISO's Hour-Ahead scheduling process, as described further in SP 7.5.

SP 7.4.5 Allocation of ~~Inter-Zonal Interface~~Transmission Pathway Capacities

In the ISO's Congestion Management analysis of the Hour-Ahead Market, for each ~~Inter-Zonal Interface~~Pathway:

(a) if all scheduled uses of transmission service fit within the total transfer capability, all are accepted (in other words, there is no Congestion);

(b) if all scheduled uses of transmission service do not fit within the total transfer capability, scheduled uses of non-firm Existing Rights will be curtailed, ~~pro rata,~~ based on the effectiveness of the resource on relieving the Congestion to the extent necessary. If the remaining scheduled uses of transmission service still do not fit within the total transfer capability, scheduled uses of conditional firm Existing Rights will be curtailed (based upon the levels of priority expressed in the contract usage templates for the Schedules as described in SP 7.2.2 (c)) to the extent necessary;

(c) if Congestion still exists after curtailing all lower priority schedules (e.g. representing non-firm and conditional firm uses of transmission service under Existing Contracts), the remaining transmission capacity (the subject of firm Existing Rights) is priced based upon ~~Adjustment~~Energy Bids. To the extent there are insufficient ~~Adjustment~~Energy Bids to fully mitigate the remaining Congestion, the default Usage Charge will apply and the ISO will curtail ISO transmission service (in other words, ~~new firm u~~New Firm Uses including ~~new firm u~~New Firm Uses of Firm Transmission Rights), ~~pro rata,~~ based on the effectiveness of the resource on relieving the Congestion to the extent necessary; and

(d) if Congestion still exists after curtailing ISO ~~new firm u~~New Firm Uses, scheduled uses of firm Existing Rights will be curtailed (based upon the priorities expressed in the contract usage template associated with the Schedules as described in SP 7.2.2 (a)) to the extent necessary.

SP 7.5 The ISO's Real-Time Process

Consistent with SP 7.4.4, the ISO will honor those scheduling flexibilities that may be exercised by holders of Existing Rights through their respective SCs during the ISO's real-time processes to the extent that such flexibilities do not interfere with or jeopardize the safe and reliable operation of the ISO Controlled Grid or Control Area operations. The real-time processes described in SP 7.5.1 and SP 7.5.2 will occur during the two~~three~~ hours following the ISO's receipt of Preferred Hour-Ahead Schedules (that is, from one~~two~~ hour~~s~~ ahead of the start of the Settlement Period through the end of such Settlement Period).

SP 7.5.1 Inter-Control Area Changes to Schedules that Rely on Existing Rights

Changes to Schedules that occur during the ISO's real-time processes that involve changes to ISO Control Area imports or exports with other Control Areas (that is, inter-Control Area changes to Schedules) will be allowed and will be recorded by the ISO based upon notification received from the SC representing the holder of the Existing Rights. The ISO must be notified of any such changes to external import/export schedules. The ISO will receive notification of real time changes to external import/export schedules, by telephone, from the SC representing the holder of the Existing Rights. The timing and content of any such notification must be consistent with the instructions previously submitted to the ISO by the Responsible PTO in accordance with the SBP. The ISO will manually adjust the SC's schedule to conform with the other Control Area's net schedule in real time, and the notifying SC will be responsible for and manage any resulting Energy imbalance. These Imbalance Energy deviations will be priced and accounted to the SC representing the holder of Existing Rights in accordance with the SABP.

SP 7.5.2 Intra-Control Area Changes to Schedules that Rely on Existing Rights

Changes to Schedules that occur during the ISO's real-time processes that do not involve changes to ISO Control Area imports or exports with other Control Areas (that is, intra-Control Area changes to Schedules) will be allowed and will give rise to Imbalance Energy deviations. These Imbalance Energy deviations will be priced and accounted to the SC representing the holder of Existing Rights in accordance with the SABP.

SP 8 OVERGENERATION MANAGEMENT

SP 8.1 Real Time Overgeneration Management

Overgeneration management in real time will be conducted in accordance with the DP.

SP 9 DAY/HOUR-AHEAD ANCILLARY SERVICES MANAGEMENT

SP 9.1 Bid Evaluation and Scheduling Principles

The ISO will evaluate Ancillary Services bids based on the following principles:

(a) the ISO will not differentiate between bidders other than through reserve (Regulation and Operating Reserves) price and capability to provide the reserve service, and the required regional ~~locational~~dispersion ~~mix~~ of services;

(b) to minimize the costs to users of the ISO Controlled Grid, the ISO will select the bidders with the lowest total capacity bid~~s~~ and opportunity cost for reserve which meet its technical requirements, including ~~location~~ regional requirement and operating capability;

(c) the ISO will (to the extent available) procure sufficient Ancillary Services to meet its technical requirements as defined in the ASRP;

(d) the ISO will evaluate and price ~~only~~ th~~os~~e Ancillary Services bids received in accordance with the SBP and the default bids created in accordance with Section 31.2.3.2.3.5.1.4;

(e) the ISO will require SCs to honor their Day-Ahead Ancillary Services schedules and/or bids when submitting their Hour-Ahead Ancillary Services schedules and/or bids. A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve or~~,~~ Non-Spinning Reserve. ~~or Replacement Reserve~~ capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, Dispatchable Load~~Curtailable Demand~~, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be at the maximum of the Day-Ahead and Hour-Ahead Anciillary Service Marginal Price ~~Market Clearing Price~~ in the Hour-Ahead Market for the same Settlement Period for the Ancillary Service capacity concerned. Increases in each Scheduling Coordinator's self-provided Ancillary Services between the Day-Ahead and Hour-Ahead Markets shall be limited to the estimated incremental Ancillary Service requirement associated with the increase between the Day-Ahead and Hour-Ahead Markets in that Scheduling Coordinator's scheduled Locational~~Zonal~~ Load. Notwithstanding this limit on increases in Hour-Ahead self-provision, a Scheduling Coordinator may buy or sell Ancillary Services through Inter-Scheduling Coordinator Ancillary Service Trades in the Hour-Ahead Market;

(~~f~~) ~~due to the design of the ISO's scheduling software, the ISO will not take into account Usage Charges in the evaluation of Ancillary Services bids or in price determination and, in the event of Congestion in the Day-Ahead Market or Hour-Ahead Market, Ancillary Services will be procured and priced on a Zonal basis; and~~

(f~~g~~) due to the design of the ISO's scheduling system, any specific resource can bid to supply a specific Ancillary Service or can self-provide such Ancillary Service but cannot do both in the same Settlement Period.

SP 9.2 ~~Sequential~~Simultaneous Evaluation of Bids

(~~a)~~ SCUC shall procure Ancillary Services at least cost simultaneous with the scheduling of Day-Ahead Energy for each hour of the Trading Day. Scheduling Coordinators may either self-provide Ancillary Services or they may submit a capacity reservation bid.

~~When SCs bid into the Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve markets, the same resource capacity may be offered into more than one of these Ancillary Services markets at the same time. The ISO will evaluate bids in the reserve markets for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve sequentially and separately in the following order:~~

~~(i) Regulation~~

~~(ii) Spinning Reserve~~

~~(iii) Non-Spinning Reserve; and~~

~~(iv) Replacement Reserve.~~

~~(b) SCs are allowed to specify different reserve prices and different Energy prices for each Ancillary Service they bid. SCs can bid~~

~~the same resource capacity into any one or all of the Ancillary Service markets they desire. Any resource capacity accepted by the ISO in one of these reserve markets will be deducted from the resource capacity bid into the other reserve markets, except that resource~~

~~capacity accepted in the Regulation market that represents the downward range of movement accepted by the ISO will not be deducted from the resource capacity bid into other reserve markets.~~

SP 9.3 Scheduling Ancillary Services Resources

(a) SCs are allowed to self-provide all or a portion of the following Ancillary Services to satisfy their obligations to the ISO:

(i) Regulation;

(ii) Spinning Reserve; and

(iii) Non-Spinning Reserve.~~; and~~

~~(iv) Replacement Reserve.~~

(b) The ISO will reduce the quantity of Ancillary Services it competitively procures by the corresponding amount of the Ancillary Services that SCs self-provide.

(c) The ISO shall prepare supplier schedules for Ancillary Services (both self-provided and purchased by the ISO) for the Day-Ahead Market and the Hour-Ahead Market.

(d) The Ancillary Services schedules shall contain the information set out in the SBP for each Settlement Period of the following Trading Day in the case of the Day-Ahead schedules or for a specific Settlement Period in the case of Hour-Ahead schedules.

(e) Once the ISO has given SCs notice of the Day-Ahead and Hour-Ahead schedules, these schedules represent binding commitments made in the reserve markets between the ISO and the SCs concerned. A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, Dispatchable Load~~Curtailable Demand~~, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replacement shall be ~~at~~ the maximum~~greater~~ of the Day-Ahead and Hour-Ahead Ancillary Service Marginal Price~~the Market Clearing Price~~ in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the ~~Zone~~ regioon in which the Generating Unit or other resources on behalf of which the Scheduling Coordinator buys back the capacity, are located. The ISO will purchase the Ancillary Service concerned from another Scheduling

Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

(f) Any minimum Energy output associated with Regulation and Spinning Reserve services shall be the responsibility of the SC, as the ISO's auction does not compensate the SC for the minimum Energy output of its Generating Units or System Unit, if any, bidding to provide these services. Accordingly, the SCs shall adjust their ~~Balanced~~ Schedules to accommodate the minimum Energy outputs required by the Generating Units or System Units, if any, included in the Ancillary Services schedules.

(g) SCs providing one or more of the Ancillary Services cannot change the identification of the Generating Units System Units or external imports of System Resources, if any, or Dispatchable Load~~Curtailable Demands~~ offered in the Day-Ahead Market, in the Hour-Ahead Market, or in the Real Time Market (except with respect to System Units, if any, in which case SCs are required to identify and disclose the resource specific information for all Generating Units and Dispatchable Load~~Curtailable Demands~~ constituting the System Unit scheduled or bid into the ISO's Day-Ahead Market and Hour-Ahead Market as required in SP 3.3.2(e)).

SP 9.4 Ancillary Service Bid Evaluation and Pricing Terminology

Unless otherwise specifically described herein, the following terminology will apply:

$CapRes_{ijt}$	=	the Ancillary Service reserve reservation bid price (in \$/MW).
$Cap_{ijt}max$	=	the maximum amount of reserve that can be scheduled by the ISO with respect to a SC's bid of that resource to supply Ancillary Services (in MW).
Cap_{ij}	=	that portion of an Ancillary Services bid (in MW), identified in the ISO's evaluation process, that may be used to meet the ISO's *Requirement* for a particular Ancillary Service ($Cap_{ijt} \leq Cap_{ijt}max$)
Requirement	=	the total amount of reserve that must be scheduled for a particular Ancillary Service required by the ISO in a Settlement Period (in MW).
i, j, t	=	Generating Unit i, Scheduling Coordinator j, Settlement Period t.

SP 9.5 Regulation Bid Evaluation and Pricing

SP 9.5.1 Regulation Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO will select Generating Units, System Units, and System Resources with the Regulation bids which minimize the sum of the total Regulation bids of the Generating Units, System Units, and System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Regulation bid must be greater than or equal to the required amount of Regulation; and

(ii) the amount of Regulation bid for each Generating Unit, System Unit, or System Resource must be less than or equal to that Generating Unit's, System Unit's, or System Resource's ramp rate times $Period_{minutes}$ where $Period_{minute}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes.

(b) The total Regulation bid for each Generating Unit, System Unit, or System Resource is calculated by multiplying the reserve reservation bid price by the sum of the amount of Regulation bid and an opportunity cost determined from the resource's Energy bid. Subject to any ~~locational~~regional requirements, the ISO will accept winning Regulation bids in accordance with ISO Tariff Appendix K.~~with the following criteria:~~

$$Min \sum_{i,j} TotalBid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt} \max$$

~~where:~~

~~$TotalBid_{ijt}$ = $Cap_{ijt} * CapRes_{ijt}$~~

~~$Requirement$ = Amount of upward and downward movement (Regulation) required by the ISO.~~

SP 9.5.2 Regulation Price Determination

The price payable to SCs for Regulation made available for upward and downward movement in accordance with the ISO's Ancillary Services schedules will, for each Generating Unit, System Unit, and System Resource concerned, be the ~~zonal Market Clearing Price~~regional Ancillary Service Marginal Price for Regulation calculated as follows:

$Pagc_{ijt} = \cancel{MCP_{xt}}\ ASMP_{xt}$

where:

the ~~zonal~~regional ~~Market Clearing Price~~Ancillary Service Marginal Price (~~*MCP*~~*ASMP*$_{xt}$) for Regulation is the marginal cost of reserving Regulation capacity from ~~highest priced winning reservation bid of~~ a Generating Unit, System Unit, or System Resource ~~serving Demand~~ in that Ancillary Services Region~~Zone X~~ based on the reservation bid price (i.e., $\cancel{MCP}ASMP_{xt} = Max\ (CapRes_{ijt})$ in that Ancillary Services Region~~Zone X~~ for Settlement Period t). In the absence of ~~Inter-Zonal~~Regional Congestion, the ~~zonal~~regional ~~Market Clearing Price~~Ancillary Service Marginal Prices will be equal.

SP 9.6 Spinning Reserves Bid Evaluation and Pricing

SP 9.6.1 Spinning Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO will select the Generating Units, System Units and external imports of System Resources with the Spinning Reserve bids which minimize the sum of the total Spinning Reserve bids of the Generating Units, System Units and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Spinning Reserve bid must be greater than or equal to the required amount of Spinning Reserve; and

(ii) the amount of Spinning Reserve bid for each Generating Unit, System Unit or external import of a System Resource must be less than or equal to that Generating Unit's, System Unit's ramp rate times 10 minutes.

(b) The total Spinning Reserve bid for each Generating Unit, System Unit or external import of a System Resource is calculated by multiplying the reserve reservation bid price by the sum of the amount of Spinning Reserve bid and an opportunity cost determined from the resource's Energy bid. . Subject to any regional ~~locational~~ requirements, the ISO will select the winning Spinning Reserve bids in accordance with ISO Tariff Appendix K. ~~with the following criteria:~~

$$Min \sum_{i,j} Totalbid_{ijt}$$

~~subject to~~

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

~~and~~

$\cancel{Cap_{ijt} \leq Cap_{ijt} max}$

~~where:~~

$\cancel{TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}}$

~~*Requirement = Amount of Spinning Reserve required by the ISO.*~~

SP 9.6.2 Spinning Reserves Price Determination

The price payable to SCs for Spinning Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit or external import of a System Resource concerned, be the ~~zonal~~regional ~~Market Clearing Price~~Ancilary Service Marginal Price for Spinning Reserve calculated as follows:

$Psp_{ijt} = \cancel{MCP}ASMP_{xt}$

where:

the ~~zonal~~regional ~~Market Clearing Price~~Ancilary Service Marginal Price (~~*MCP*~~*ASMP*$_{xt}$) for Spinning Reserve is the marginal cost of reserving Spinning reserve ~~highest priced winning reservation bid of a~~ Generating Unit, System Unit or external import of a System Resource ~~serving Demand~~ in that Ancillary Services Region ~~Zone X~~ based on the reservation bid price (i.e., ~~*MCP*~~*ASMP*$_{xt}$ = *Max(CapRes*$_{ijt}$*)* in ~~*Zone X*~~ for Settlement Period t). In the absence of Inter-~~Zonal~~Regional Congestion, the ~~zonal~~regional ~~Market Clearing Prices~~ASMP will be equal.

SP 9.7 Non-Spinning Reserves Bid Evaluation and Pricing

SP 9.7.1 Non-Spinning Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Dispatchable Loads~~Curtailable Demands~~ and external imports of System Resources with the Non-Spinning Reserve bids which minimize the sum of the total Non-Spinning Reserve bids of the Generating Units, System Units, Dispatchable Loads~~Curtailable Demands~~ and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Non-Spinning Reserve bid must be greater than or equal to the required amount of Non-Spinning Reserve; and

(ii) the amount of Non-Spinning Reserve bid for each Generating Unit, System Unit, or Dispatchable Loads~~Curtailable Demand~~ must be less than or equal to that Generating Unit's, System Unit's, or Dispatchable Load~~Curtailable Demand~~'s, or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 10 minutes and the time to synchronize in the case of a Generating Unit, or to interruption in the case of a Load.

(b) The total Non-Spinning Reserve bid for each Generating Unit, System Unit, ~~Curtailable~~Dispatchable Load ~~Demand~~ or external import of a System Resource is calculated by multiplying the sum of the reserve reservation bid price and an opportunity cost determined from the resource's Energy bid where applicable. by the amount of Non-Spinning Reserve bid.

Subject to any locational requirements, the ISO will accept the winning Non-Spinning Reserve bids in accordance with ISO Tariff Appendix K.~~the following criteria~~:

$$Min\sum_{i,j} Totalbid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt}max$$

~~where:~~

~~$TotalBid_{ijt}$ = $Cap_{ijt} * CapRes_{ijt}$~~

~~$Requirement$ = Amount of Non-Spinning Reserve required by the ISO.~~

SP 9.7.2 Non-Spinning Reserves Price Determination

The price payable to SCs for Non-Spinning Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit, Dispatchable Loads~~Curtailable Demand~~ or external import of a System Resource concerned, be the ~~zonal~~regional Market Clearing Price for Non-Spinning Reserve calculated as follows:

$Pnonsp_{ijt} = \cancel{MCP}ASMP_x$

where:

the ~~zonal~~regional ~~Market Clearing Price~~Ancillary Service Marginal Price ($\cancel{MCP}ASMP_{xt}$) for Non-Spinning Reserve is the marginal cost of reserving Non-Spinning reserve ~~highest priced winning reservation bid~~ of a Generating Unit, System Unit, ~~Curtailable Demand~~Dispatchable Load or external import of a System Resource ~~serving Demand~~ in that Ancillary Service Region ~~Zone X~~ based on the reservation bid (i.e., $\cancel{MCP}ASMP_{xt} = Max(CapRes_{ijt})$ in ~~Zone X~~ for Settlement Period t). In the absence of ~~Inter-Zonal~~Regional Congestion, the ~~zonal~~regional ~~Market Clearing Prices~~ ASMP will be equal.

~~**SP 9.8 Replacement Reserves Bid Evaluation and Pricing**~~

~~**SP 9.8.1 Replacement Reserves Bid Evaluation**~~

~~(a) Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Curtailable Demands and external imports of a System Resources with the Replacement Reserve bids which minimize the sum of the total Replacement Reserve bids of the Generating Units, System Units, Curtailable Demands and external imports of System Resources selected subject to two constraints:~~

~~(i) the sum of the selected amounts of Replacement Reserve bid must be greater than or equal to the required amount of Replacement Reserve; and~~

~~(ii) the amount of Replacement Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource must be less than or equal to that Generating Unit's, System Unit's, Curtailable Demand's or external import's ramp~~

~~rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 60 minutes and the time to synchronize in the case of Generating Unit, or to interruption in the case of Load.~~

~~(b) The total Replacement Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource is calculated by multiplying the reserve reservation bid price by the amount of Replacement Reserve bid. Subject to any locational requirements, the ISO will select the winning Replacement Reserve bids in accordance with the following criteria~~:

$$Min \sum_{i,j} Totalbid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt} max$$

~~where:~~

~~*TotalBid*~~$\cancel{_{ijt}}$ ~~= *Cap*~~$\cancel{_{ijt}}$ ~~* *CapRes*~~$\cancel{_{ijt}}$

~~*Requirement* = *Amount of Replacement Reserve required by the ISO.*~~

~~SP 9.8.2 Replacement Reserves Price Determination~~

~~The price payable to SCs for Replacement Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource concerned, be the zonal Market Clearing Price for Replacement Reserve calculated as follows:~~

$\cancel{Prepres_{ijt} = MCP_{xt}}$

~~where:~~

~~the zonal Market Clearing Price (~~$\cancel{MCP_{xt}}$~~) for Replacement Reserve is the highest priced winning reservation bid of a Generating Unit, System Unit, Curtailable Demand or external import of a System Resource serving Demand in Zone X based on the reservation bid price (i.e.,~~ $\cancel{MCP_{xt} = Max(CapRes_{ijt})}$ ~~in Zone X for Settlement Period t). In the absence of Inter-Zonal Congestion, the zonal Market Clearing Prices will be equal.~~

SP 9.9 Existing Contracts – Ancillary Services Accountability

Certain Existing Contracts may have requirements for Ancillary Services which differ from the requirements of this SP 9. Each PTO will be responsible for recovering any deficits or crediting any surpluses associated with differences in assignment of Ancillary Services requirements, through its bilateral arrangements or its Transmission Owner's Tariff. The ISO will not undertake the settlement or billing of any such differences under any Existing Contract.

SP 10 DAY/HOUR-AHEAD INTER-ZONAL CONGESTION MANAGEMENT

SP 10.1 Congestion Management Assumptions

The ~~Inter-Zonal~~ Congestion Management process is based upon the following assumptions:

~~(a) Inter-Zonal Congestion Management will ignore Intra-Zonal Congestion. Intra-Zonal Congestion will be managed in real time;~~

(a~~b~~) ~~Inter-Zonal~~ Congestion Management will be performed as part of the simultaneous Energy and Ancillary Service markets and will make use of an ~~D~~AC optimal power flow (OPF) program that uses linear optimization techniques with active power (MW) controls only; and

(b~~c~~) transmission capacity reserved under Existing Contracts will not be subject to the ISO's Congestion Management procedures.

SP 10.2 Congestion Management Process

(a) ~~Inter-Zonal~~ Congestion Management will involve adjusting Schedules to remove potential transmission security violations and ~~of Inter-Zonal Interface~~Pathway constraints, minimizing the ~~re~~dispatch cost, as determined by the submitted ~~Adjustment~~ Energy Bids that accompany the submitted Schedules. See the SBP for a general description of the use of Energy~~Adjustment~~ Bids to establish priorities.

~~(b) Inter-Zonal Congestion Management will not involve arranging or modifying trades between SCs. Each SC's portfolio will be kept in balance (i.e., its Generation plus external imports, as adjusted for Transmission Losses, and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) will still match its Demand plus external exports) after the adjustments. Market Participants will have the opportunity to trade with one another and to revise their Schedules during the first Congestion Management iteration in the Day-Ahead Market, and between the Day-Ahead Market and Hour-Ahead Market.~~

~~(c) Inter-Zonal Congestion Management will also not involve the optimization of SC portfolios within Zones (where such apparently non-optimal Schedules are submitted by SCs). Adjustments to individual SC portfolios within a Zone will be either incremental (i.e., an increase in Generation and external imports and a decrease in Demand and external exports) or decremental (i.e., a decrease in Generation and external imports and an increase in Demand and external exports), but not both.~~

(b~~d~~) If Energy ~~Adjustment~~ Bids are exhausted before Congestion is eliminated, the remaining Schedules will be adjusted ~~*pro rata*~~ based on default Energy Bids generated in accordance with Section 31.2.3.2.3.4.5 except for those uses of transmission service under Existing Contracts, which are curtailed in accordance with SP 7.3 and SP 7.4.

SP 10.3 Congestion Management Pricing

(a) The Energy~~Adjustment~~ Bids that the SCs submit constitute ~~implicit~~ bids to manage Congestion;~~for transmission between Zones on either side of a Congested Inter-Zonal Interface. The ISO's Inter-Zonal~~

~~Congestion Management process will allocate Congested transmission to those users who value it the most and will charge all SCs for their allocated usage of Congested Inter-Zonal Interfaces on a comparable basis. All SCs within a Zone will see the same price for transmitting Energy across a Congested Inter-Zonal Interface, irrespective of the particular locations of their Generators, Demands and external imports/exports.~~

(b) The ISO will determine the prices for the use of Congested ~~Inter-Zonal Interfaces~~Pathways using the ~~Adjustment~~Energy Bids. The ISO will collect ~~Usage Charges~~Congestion Revenue from SCs for their Scheduled use. ~~of Congested Inter-Zonal Interfaces.~~Pathways. If ~~Adjustment~~Energy Bids are exhausted and Schedules are adjusted based on Default energy bids~~*pro rata*, the ISO will apply a default Usage Charge calculated in accordance with Section 7.3.1.3 of the ISO Tariff.~~

(c) The ISO will rebate the Congestion R~~r~~evenues collected through ~~the Usage Charges to the PTOs which own the Congested~~to FTR holders. Point-To-Point Right FTR Holders shall be entitled to the difference in the Locational Marginal Prices (LMPs) between the Sink and the Source, multiplied by the awarded quantities at the Sink and Source. These Point-To-Point Rights may include multiple Sources and Sinks that have been aggregated into single Trading Hubs and are represented by a single price and quantity. ~~Inter-Zonal Interface in proportion to their respective ownership rights~~.

SP 11 ~~CREATION OF THE REAL TIME MERIT ORDER STACK~~REAL TIME ECONOMIC DISPATCH

SP 11.1 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) unused Energy Bids submitted to the Hour-Ahead Market;~~Supplemental Energy bids submitted in accordance with the SBP~~;

(b) Energy bids associated with awarded Ancillary Services capacity; and ~~Energy bids (except for Regulation) submitted for specific Ancillary Services in accordance with the SBP for those resources which have been selected in the ISO's Ancillary Services auction to supply such specific Ancillary Services; and~~

(c) Energy associated with capacity committed in the Residual Unit Commitment Process.~~Ancillary Services Energy bids (except for Regulation) submitted for specific Ancillary Services in accordance with the SBP for those resources which SCs have elected to use to self-provide such specific Ancillary Services and for which the ISO has accepted such self-provision.~~

SP 11.2 **Dispatching~~Stacking of the~~ Energy Bids**

The sources of Imbalance Energy described in SP 11.1 will be ~~arranged~~ Dispatched in order ~~of increasing Energy bid~~ to minimize the costs of imbalance energy subject to transmission and other resource constraints through the Security Constrained Economic Dispatch (SCED). SCED will also produce Locational Marginal Prices for Energy that reflect the marginal costs of Imbalance Energy at each Location in the ISO Controlled Grid.~~. prices to create a merit order stack for use in accordance with the DP. This merit order stack will be arranged~~Dispatch of Imbalance Energy will be done without regard to the source of the Energy Bid except that Energy Bids associated with Spinning and Non-Spinning Reserve shall not be Dispatched~~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 Dispatched by~~included in the merit order stack~~ SCED. ~~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 BEEP (Balancing Energy and Ex-Post Pricing) Software.~~

Where, in any ~~BEEP~~ Dispatch Interval, the highest decremental Energy Bid available ~~in the merit order stack~~ is higher than the lowest available incremental Energy Bid, the ~~BEEP~~ SCED 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.

SP 11.3 Use of the ~~Merit Order Stack~~Imbalance Energy Bids

The ~~merit order stack~~Imbalance Energy Bids, as described in SP 11.2, 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) managing Intra-Zonal Congestion in real time after use of available Adjustment Bids.~~

SP 12 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

SETTLEMENT AND BILLING PROTOCOL

SETTLEMENT AND BILLING PROTOCOL

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SETTLEMENT AND BILLING PROTOCOL (SABP)

SABP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SABP 1.1 Objectives

The objective of this Protocol (and of Annex 1) is to inform Scheduling Coordinators, Participating TOs, Utility Distribution Companies, Metered Subsystems, and Operators of Reliability Must-Run Units of the manner in which the charges referred to in Section 11.1.6 of the ISO Tariff shall be calculated and settled and of the procedures regarding the billing, invoicing and payment of these charges.

SABP 1.2 Definitions

SABP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section is to a Section of the ISO Tariff. References to SABP are to this Protocol or to the stated paragraph of this Protocol. References to Annex 1 are to Annex 1 of this Protocol.

SABP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Black Start Generator" means a Participating Generator in its capacity as party to an Interim Black Start Agreement with the ISO for the provision of Black Start Services, but shall exclude Participating Generators in their capacity as providers of Black Start services under their Reliability Must-Run Contracts.

"Day 0" means the Trading Day to which the Settlement Statement or settlement calculation refers. For example "Day 41" shall mean the 41st day after that Trading Day and similar expressions shall be construed accordingly.

"Fed-Wire" means the Federal Reserve Transfer System for electronic funds transfer.

"Interim Black Start Agreement" means an agreement entered into between the ISO and a Participating Generator (other than a Reliability Must-Run Agreement) for the provision by the Participating Generator of Black Start capability and Black Start Energy on an interim basis until the introduction by the ISO of its Black Start auction (or until terminated earlier by either party in accordance with its terms).

"ISO Surplus Account" means the account established by the ISO pursuant to SABP 6.5.

"ISO Home Page" means the ISO internet home page at http://www.caiso.com/iso or such other internet address as the ISO shall publish from time to time.

"Security" means the form of security provided by a Scheduling Coordinator pursuant to Section 2.2.3.2 of the ISO Tariff (i.e. letter of credit, guarantee or cash deposit) to secure its trading obligations.

"Trading Interval" means a Settlement Period as defined in the Master Definitions Supplement of the ISO Tariff.

SABP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) A reference to a day or Trading Day is to a calendar day unless otherwise specified.

SABP 1.2.4 Time

All references to time are references to prevailing Pacific Time.

SABP 1.2.5 Financial Transaction Conventions

In this Protocol and its Appendices and Annex 1, the following conventions have been adopted in defining sums of money to be remitted to or received by the ISO:

(a) where the ISO is to receive a sum of money under this Protocol, this is defined as a "Charge";

(b) where the ISO is to required to pay a sum of money under this Protocol, this is defined as a "Payment".

SABP 1.2.6 Currency

All financial transactions are denominated in US dollars and cents.

SABP 1.3 Scope

SABP 1.3.1 Scope of Application to Parties

This Protocol (excluding Annex 1) applies to the ISO and to the following entities:

(a) Scheduling Coordinators;

(b) Participating TOs;

(c) Black Start Generators;

(d) Utility Distribution Companies, and

(e) Metered Subsystems.

The settlement, billing and payment process between the ISO, Scheduling Coordinators, Participating TOs, Black Start Generators, Utility Distribution Companies, and Metered Subsystems shall be in accordance with Sections 11.3 to 11.24 inclusive of the ISO Tariff. References in those Sections to Scheduling Coordinators shall also apply to Participating TOs which receive Settlement Statements from the ISO in relation to the transactions referred to in those Settlement Statements but excluding the transactions referred to in Annex 1. Notwithstanding SABP 1.2.3(a), references in Sections 11.3 to 11.24 inclusive of the ISO Tariff to Scheduling Coordinators, ISO Debtors and ISO Creditors shall also apply to Black Start Generators which receive Settlement Statements from the ISO in relation to transactions under their Interim Black Start Agreements.

Annex 1 of this Protocol applies to the ISO, Owners of Reliability Must-Run Units and Participating TOs in relation to the billing and payment of amounts due under Reliability Must-Run Contracts and recovery of such amounts by the ISO from Participating Utilities. The provisions of this Protocol shall not apply to Annex 1 unless otherwise specified.

SABP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

SABP 2 OVERVIEW OF SETTLEMENT AND BILLING PROCESS

SABP 2.1 Settlement Software

The ISO settlement software shall be audited by an independent firm of auditors competent to carry out audits of such software to determine its consistency with this Protocol and the ISO Tariff. In any dispute regarding Settlement calculations, a certificate of such firm of auditors that the ISO software is consistent with the ISO Tariff shall be prima facie proof that the charges shown in a Settlement Statement have been calculated in a method consistent with the ISO Tariff and this Protocol. Nothing in this section will be deemed to establish the burden of proof with respect to Settlement calculations in any proceeding.

SABP 2.2 ISO Accounts

SABP 2.2.1 Costs Associated with the ISO Trust Accounts

The ISO is authorized to establish and maintain bank accounts held in trust for Market Participants and obtain lines of credit and other banking facilities (not exceeding an aggregate amount set by the ISO Governing Board) necessary for the operation of its Settlement and billing procedures. Unless otherwise specified in this Protocol the ISO will recover all costs incurred in connection with these ISO banking facilities through the appropriate component of the Grid Management Charge.

SABP 2.2.2 Location of the ISO Accounts

The ISO will maintain its bank accounts held on trust at a bank in California approved by the ISO Governing Board.

SABP 2.2.3 ISO Trust Accounts

The ISO will open and operate the following accounts which it will hold on trust for Market Participants:

(a) the ISO Clearing Account to and from which payments are made pursuant to Section 11.8.2.1 of the ISO Tariff and SABP 6.3.1;

(b) the ISO Reserve Account from which any debit balances on the ISO Clearing Account at the close of banking business are settled pursuant to Section 11.8.2.2 of the ISO Tariff and SABP 6.4; and

(c) the ISO Surplus Account consistent with Section 11.8.2.3 of the ISO Tariff and SABP 6.5.

The ISO may establish additional trust accounts as necessary to implement the Settlement and billing procedures outlined in this Protocol. It shall notify the Market Participants of the establishment of such accounts through the WEnet.

SABP 2.2.4 The ISO Clearing Account

Subject to SABP 6.1.2, ISO Debtors shall make all payments of ISO invoices by Fed-Wire to the ISO Clearing Account by 10:00 am on the due date according to the ISO Payments Calendar.

SABP 2.2.5 The ISO Reserve Account

The ISO shall operate the ISO Reserve Account as a trust account as follows:

(a) the proceeds of drawings under any line of credit or other credit facility of the ISO Reserve Account shall be held on trust for ISO Creditors;

(b) if the Reserve Account is replenished as provided for in SABP 6.9, any credits shall be held on trust for all ISO Creditors.

SABP 2.2.6 Accounts of the SCs and Participating TOs

Each Scheduling Coordinator and each Participating TO shall establish and maintain a Settlement Account at a commercial bank located in the United States and reasonably acceptable to the ISO which can effect money transfers via Fed-Wire where payments to and from the ISO Clearing Account shall be made in accordance with this Protocol. Scheduling Coordinators may, but will not be required to, maintain separate accounts for receipts and payments. Each Scheduling Coordinator shall notify the ISO of its account details and of any changes to those details in accordance with the provisions of its SC Agreement. Participating TOs will notify the ISO of their Settlement Account details in accordance with Section 2.2.1 of their Transmission Control Agreement and may notify the ISO from time to time of any changes by giving at least 7 days written notice before the new account becomes operational.

SABP 2.3 ISO Payments Calendar

SABP 2.3.1 Contents of ISO Payments Calendar

In September of each year, the ISO will prepare a draft ISO Payments Calendar for the following calendar year showing for each Trading Day:

(a) The date by which Scheduling Coordinators are required to provide Settlement Quality Meter Data for all their Scheduling Coordinator Metered Entities for each Settlement Period in the Trading Day;

(b) The date on which the ISO will issue Preliminary Settlement Statements and invoices to Scheduling Coordinators, Black Start Generators and Participating TOs for that Trading Day;

(c) The date by which Scheduling Coordinators, Black Start Generators and Participating TOs are required to notify the ISO of any disputes in relation to their Preliminary Settlement Statements pursuant to SABP 4.4.1 and the ISO Tariff;

(d) The date on which the ISO will issue Final Settlement Statements and invoices to Scheduling Coordinators, Black Start Generators and Participating TOs for that Trading Day;

(e) The date and time by which ISO Debtors are required to have made payments into the ISO Clearing Account in payment of invoices for that Trading Day; and

(f) The dates and times on which ISO Creditors will receive payments from the ISO Clearing Account of amounts owing to them for that Trading Day.

(g) In relation to Reliability Must-Run Charges and Payments, the details set out in paragraph 3 of Annex 1.

SABP 2.3.2 Calendar Content and Format

In accordance with SABP 2.3.3, 2.3.4 and 2.3.5 the ISO may change the content or format of the ISO Payments Calendar. The ISO may also produce a summary outline of the Settlement and billing cycles.

SABP 2.3.3 Draft Payments Calendar

In September of each year, the ISO will make a draft of the ISO Payments Calendar available on the ISO Home Page to Scheduling Coordinators, Black Start Generators, Participating TOs and Owners any of which may submit comments and objections to the ISO within two weeks of the date of posting of the draft on the ISO Home Page.

SABP 2.3.4 Final Payments Calendar

No later than October 31st in each year, the ISO will publish pursuant to Section 11.24.1 of the ISO Tariff the final ISO Payments Calendar for the following calendar year, after considering the comments and objections received from Scheduling Coordinators, Black Start Generators, Participating TOs and Owners. The final ISO Payments Calendar will be posted on the ISO Home Page.

SABP 2.3.5 Update the Final Payments Calendar

If as a result of a tariff amendment approved by FERC the final ISO Payments Calendar developed in accordance with SABP 2.3.3 and 2.3.4 above is rendered inconsistent with the timing set forth in the tariff, the ISO shall update the final ISO Payments Calendar to make it consistent with the tariff as approved by FERC on the date on which the tariff amendment goes into effect. The ISO shall simultaneously send out a notice to market participants that the final ISO Payments Calendar has been revised.

SABP 2.3.6 Final Calendar Binding

The final ISO Payments Calendar shall be binding on the ISO and on Scheduling Coordinators, Black Start Generators, Participating TOs and Owners.

SABP 3 COMPUTATION OF CHARGES

SABP 3.1 Description of Charges to be Settled

The ISO shall, based on Final Day-Ahead and Hour-Ahead schedules, ~~-~~the Settlement Quality Meter Data it has received, or, if Settlement Quality Meter Data is not available, based on the best available information or estimate it has received, calculate the following:

(a) the amount due from each Scheduling Coordinator or other appropriate party for its share for the relevant month of the three components of the Grid Management Charge in accordance with Appendix A. These Charges shall accrue on a monthly basis.

(b) ~~the amount due from each Scheduling Coordinator for the Grid Operations Charge in accordance with Appendix A. This charge shall accrue on a monthly basis.~~[Not Used]

(c) the amount due from and/or owed to each Scheduling Coordinator for the Charge for each Ancillary Service in accordance with Appendix C, for each of the Settlement Periods of Day 0.

(d) the amount due from and/or owed to each Scheduling Coordinator for Imbalance Energy in accordance with Tariff Section 31.4.3.4.4 and SABP Appendix D, for each of the Settlement Periods of Day 0.

(e) the amount due from and/or owed to each Scheduling Coordinator for ~~Usage Charges~~Day-Ahead and/or Hour-Ahead Energy in accordance with Appendix E, for each of the Settlement Periods of Day 0.

(f) the amount due from each Scheduling Coordinator for Wheeling Out and Wheeling Through Charges and the amount owed to each Participating TO for these charges in accordance with Appendix F, for each of the Settlement Periods of Day 0.

(g) the amounts due from/to Scheduling Coordinators for Voltage Support (supplemental reactive power charges) for each of the Settlement Periods of Day ~~O~~ 0 in accordance with Appendix G.

(h) the monthly charges due from/to Scheduling Coordinators for long term voltage support provided by Owners of Reliability Must-Run Units in accordance with Appendix G.

(i) the amounts due from/to Scheduling Coordinators for the provision of Black Start Energy from Reliability Must-Run Units for each of the Settlement Periods of Day 0~~O~~ in accordance with Appendix G.

(j) the amounts due from/to Black Start Generators for the provision of Black Start Energy for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(k) the amount due from each UDC or MSS, or from a Scheduling Coordinator delivering Energy for the supply of Gross Load not directly connected to the facilities of a UDC or MSS, for the High Voltage Access Charge and Transition Charge in accordance with operating procedures posted on the ISO Home Page. These charges shall accrue on a monthly basis.

(l) the amounts due from Scheduling Coordinators for FERC Annual Charges.

The payments or charges to FTR Holders associated with FTRs;

(n) the amount due to or from Scheduling Coordinators for the unrecovered costs associated with committing resources in the Day-Ahead and Hour-Ahead Energy markets in accordance with Appendix H, for each of the Settlement Periods of Day 0.

(o) the amount due to or from Scheduling Coordinators for the capacity payments and unrecovered costs associated with committing resources in the Day-Ahead and Hour-Ahead Residual Unit Commitment in accordance with Section 31.4.3.4.4 and Appendix H, for each of the Settlement Periods of Day 0.

All of the data, information, and estimates the ISO uses to calculate these amounts shall be subject to the auditing requirements of Section 10.5 of the ISO Tariff.

The ISO shall calculate these amounts using the software referred to in SABP 2.1 except in cases of system breakdown when it shall apply the procedures set out in SABP 9 (Emergency Procedures).

SABP 3.1.1 Additional Charges and Payments

The ISO shall be authorized to levy additional charges or payments as special adjustments in regard to:

(a) amounts required to round up any invoice amount expressed in dollars and cents to the nearest whole dollar amount in order to clear the ISO Clearing Account. These charges will be allocated amongst Scheduling Coordinators over an interval determined by the ISO and pro rata based on metered Demand (including exports) during that interval;

(b) amounts in respect of penalties which may be levied by the ISO in accordance with the ISO Tariff. These charges will be levied on the Market Participants liable for payment of the penalty; and

(c) amounts required to reach an accounting trial balance of zero in the course of the Settlement process in the event that the charges calculated as due from ISO Debtors are lower than payments calculated as due to the ISO Creditors for the same Trading Day. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day. In the event that the charges due from ISO Debtors are higher than the payments due to ISO Creditors, the ISO shall allocate a payment to the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day.

(d) amounts required with respect to payment adjustments for regulating Energy as calculated in accordance with Section 2.5.27.1 of the ISO Tariff. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh for that Trading Day.

SABP 3.2 Method of Settlement of Charges

SABP 3.2.1 Settlement of Payments to/from Scheduling Coordinators and Participating TOs

The ISO will calculate for each charge the amounts payable by the relevant Scheduling Coordinator, Black Start Generator or Participating TO for each Settlement Period of the Trading Day, and the amounts payable to that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for each Settlement Period of that Trading Day and shall arrive at a net amount payable for each charge by or to that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for that Trading Day. Each of these amounts will appear in the Preliminary and Final Settlement Statements that the ISO will provide to the relevant Scheduling Coordinator, Black Start Generator or Participating TO as provided in SABP 4.

The three components of the Grid Management Charge will be included in the Preliminary Settlement Statement and Final Settlement Statement with the other types of charges referred to in SABP 3.1, but a separate invoice for the Grid Management Charge, stating the rate, billing determinant volume and total charge for each of its three components, will be issued by the ISO.

SABP 4 SETTLEMENT STATEMENTS

SABP 4.1 Preliminary Settlement Statements

SABP 4.1.1 Timing of Preliminary Settlement Statements

The ISO shall provide to each Scheduling Coordinator, Black Start Generator or Participating TO for validation a Preliminary Settlement Statement for each Trading Day in accordance with the ISO Payments Calendar.

SABP 4.1.2 Contents of Preliminary Settlement Statements

Each Preliminary Settlement Statement will include a statement of:

(a) the amount payable or receivable by the Scheduling Coordinator, Black Start Generator or Participating TO for each charge referred to in SABP 3 for each Settlement Period in the relevant Trading Day;

(b) the total amount payable or receivable by that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for all Settlement Periods in that Trading Day after the amounts payable and the amounts receivable under (a) have been netted off pursuant to SABP 3.2.1; and

(c) the components of each charge in each Settlement Period except for information contained in the Imbalance Energy Report referred to in SABP 4.1.3.

SABP 4.1.3 Imbalance Energy Report

Each Preliminary Settlement Statement shall be accompanied by a breakdown of the components of the Imbalance Energy Charge (the "Imbalance Energy Report").

SABP 4.2 Final Settlement Statements

The ISO shall provide to each Scheduling Coordinator, Black Start Generator or Participating TO a Final Settlement Statement in accordance with the ISO Tariff and the ISO Payments Calendar. The Final Settlement Statement shall be in a format similar to that of the Preliminary Settlement Statement and shall include all the information provided in the Preliminary Settlement Statement as amended following the validation procedure set forth in SABP 4.3 and 4.4.

SABP 4.3 Review, Validation, Confirmation of Preliminary Settlement Statements

The provisions for confirmation, review and validation of Preliminary Settlement Statements set forth in Sections 11.6.1.2, 11.7.1, 11.7.2, 11.7.3 and 11.7.4 of the ISO Tariff shall apply to all Scheduling Coordinators, Black Start Generators or Participating TOs (save, in the case of Participating TOs, for charges or rebates referred to in Annex 1) who receive a Preliminary Settlement Statement from the ISO.

SABP 4.4 Resolving Disputes Relating to Preliminary and Final Settlement Statements

SABP 4.4.1 Notice

SABP 4.4.1.1 Notice of an ordinary dispute

If a Scheduling Coordinator, Black Start Generator or Participating TO disputes any item or calculation set forth in its Preliminary or Final Settlement, it shall provide the ISO by electronic means with a notice of dispute within eight (8) Business Days from the date of issue of the Preliminary Settlement Statement or within ten (10) Business Days from the date of issue of the Final Settlement Statement.

SABP 4.4.1.2 Notice of recurring dispute

If a Scheduling Coordinator, Black Start Generator or Participating TO believes a dispute will apply to subsequent Preliminary or Final Settlement Statements, it may request, in a notice provided in accordance with Section SABP 4.4.1.1 above, that the ISO treat the dispute as recurring. A request for recurring treatment may be made for any valid reason provided that subsequent Preliminary and Final Settlement Statements would be affected, including but not limited to, that the disputed calculation will recur, or that a disagreement as to policy will affect calculations in subsequent Preliminary and Final Settlement Statements.

SABP 4.4.2 Contents of Notice

SABP 4.4.2.1 Contents of a notice of dispute

The notice of dispute shall state clearly the Trading Day, the issue date of the Preliminary of Final Settlement Statement, the item disputed, the reasons for the dispute, the amount claimed (if appropriate) and shall be accompanied with all available evidence reasonably required to support the claim.

SABP 4.4.2.2 Contents of a request for treatment as a recurring dispute

If a Scheduling Coordinator, Black Start Generator or Participating TO wishes to request that the ISO treat a dispute as recurring, it shall, in the notice provided in accordance with Section SABP 4.4.2.1 above, clearly indicate that it requests such treatment and set forth in detail the reasons that support such treatment. To the extent possible, the Scheduling Coordinator, Black Start Generator or Participating TO shall state the types of charges and dates to which the dispute will apply, and provide estimates of the amounts that will likely be claimed on each date.

SABP 4.4.3 ISO determination of a recurring dispute

The ISO may deny a request that the ISO treat a dispute as recurring for any valid reason, including because the request is not adequately specific as to the basis for recurring treatment or the subsequent calculations that will be affected.

SABP 4.4.4 Amendment

Regarding a dispute related to a Preliminary Settlement Statement, if the ISO agrees with the amount claimed, it shall incorporate the relevant data into the Final Settlement Statement. Regarding a dispute related to an Incremental Change in a Final Settlement Statement, the ISO shall make a determination on the dispute no later than twenty-five (25) Business Days from the issuance of the Final Settlement Statement, and, if the ISO agrees with the amount claimed, shall incorporate the relevant data into the next available Preliminary Settlement Statement.

SABP 4.4.5 ISOContact

If the ISO does not agree with the amount claimed or if it requires additional information, it shall make reasonable efforts (taking into account the time it received the notice of dispute and the complexity of the issue involved) to contact the relevant Scheduling Coordinator, Black Start Generator or Participating TO to resolve the issue before issuing the Final Settlement Statement. If it is not possible to contact the relevant party, the ISO shall issue the Final Settlement Statement without taking into account the dispute notice.

SABP 4.4.6 Payment Pending Dispute

Each Scheduling Coordinator, Black Start Generator or Participating TO which receives an invoice shall pay any net debit and shall be entitled to receive any net credit shown in the invoice on the Payment Date, whether or not there is any dispute regarding the amount of the debit or credit. The provisions of Section 13 (Dispute Resolution) of the ISO Tariff shall apply to the disputed amount.

SABP 4.5 Settlement Statement Re-runs

SABP 4.5.1 Notice

If a Scheduling Coordinator, Black Start Generator or Participating TO, (having made reasonable efforts to resolve with the ISO any dispute relating to a Preliminary Settlement Statement pursuant to SABP 4.4) requires a Settlement Statement re-run, it shall send at any time to the ISO Governing Board a notice in writing.

SABP 4.5.2 ISO Tariff

The provisions of Sections 11.6.3, 11.6.3.1, 11.6.3.2 and 11.6.3.3 of the ISO Tariff relating to Settlement Statement re-runs shall apply to all Scheduling Coordinators, Black Start Generators or Participating TOs who require a Settlement re-run in accordance with this SABP 4.5.

SABP 5 INVOICES

The ISO shall provide on the day specified in the ISO Payments Calendar an invoice in the format set out in SABP Appendix I showing:

(a) amounts which according to each of the Preliminary and Final Settlement Statements of that Billing Period are to be paid from or to each Scheduling Coordinator, Black Start Generator or Participating TO;

(b) the Payment Date, being the date on which such amounts are to be paid or received and the time for such payment; and

(c) details (including the account number, bank name and Fed-Wire transfer instructions) of the ISO Clearing Account to which any amounts owed by the Scheduling Coordinator, Black Start Generator or Participating TO are to be paid.

A separate invoice for the Grid Management Charge, stating the rate, billing determinant volume and total charge for each of its three components, will be issued by the ISO.

SABP 6 PAYMENT PROCEDURES

SABP 6.1 Time of Payment

SABP 6.1.1 Payment Date

Subject to SABP 6.1.2, payment will be made by the ISO and by each Scheduling Coordinator, Black Start Generator and Participating TO on the Payment Date as set forth in Section 11.3.2.

SABP 6.1.2 Prepayments

(a) A Scheduling Coordinator may choose to pay at an earlier date than the Payment Date specified in the ISO Payments Calendar by way of prepayment provided it notifies the ISO by electronic means before submitting its prepayment.

(b) Prepayment notifications must specify the dollar amount prepaid.

(c) Prepayments must be made by Scheduling Coordinators via Fed-Wire into their ISO prepayment account designated by the ISO. The relevant Scheduling Coordinator shall grant the ISO a security interest on all funds in its ISO prepayment account.

(d) On any Payment Date the ISO shall be entitled to cause funds from the relevant Scheduling Coordinator's ISO prepayment account to be transferred to the ISO Clearing Account in such amounts as may be necessary to discharge in full that Scheduling Coordinator's payment obligation arising in relation to that Payment Date.

(e) Any funds held in the relevant Scheduling Coordinator's ISO prepayment account shall be treated as part of that Scheduling Coordinator's Security.

(f) Interest (or other income) accruing on the relevant Scheduling Coordinator's ISO prepayment account shall inure to the benefit of that Scheduling Coordinator and shall be added to the balance of its ISO prepayment account on a monthly basis.

(g) Funds held in an ISO prepayment account by a Scheduling Coordinator may be recouped, offset or applied by the ISO to any outstanding financial obligations of that Scheduling Coordinator to the ISO or to other Scheduling Coordinators under this Protocol.

SABP 6.2 Payments to be made by Fed-Wire

All payments by the ISO to Scheduling Coordinators, Black Start Generators and Participating TOs shall be made by Fed-Wire.

All payments to the ISO by Scheduling Coordinators, Black Start Generators and Participating TOs shall be made by Fed-Wire.

SABP 6.3 **Payment Process**

SABP 6.3.1 **Use of the ISO Clearing Account**

(a) Subject to SABP 6.1.2 each ISO Debtor shall remit to the ISO Clearing Account the amount shown on the invoice as payable by that ISO Debtor for value not later than 10:00 am on the Payment Date.

(b) On the Payment Date the ISO shall be entitled to cause the transfer of such amounts held in a Scheduling Coordinator's ISO prepayment account to the ISO Clearing Account as provided in SABP 6.1.2(c).

SABP 6.3.1.2 **Distribution to ISO Creditors**

The ISO shall calculate the amounts available for distribution to ISO Creditors on the Payment Date and shall give irrevocable instructions to the ISO Bank to remit from the ISO Clearing Account to the relevant Settlement Account maintained by each ISO Creditor for same day value the amounts determined by the ISO to be available for payment to each ISO Creditor. If required, the ISO shall instruct the ISO Bank to transfer amounts from the ISO Reserve Account to enable the ISO Clearing Account to clear by the close of banking business on the Payment Date.

SABP 6.3.1.3 **Grid Management Charge**

The ISO is authorized to instruct the ISO Bank to debit the ISO Clearing Account and transfer to the relevant ISO account sufficient funds to pay in full the Grid Management Charge falling due on any Payment Day with priority over any other payments to be made on that or on subsequent days out of the ISO Clearing Account.

SABP 6.4 **Use of the ISO Reserve Account**

If there are insufficient funds in the ISO Clearing Account to pay ISO Creditors and clear the account on any Payment Date, due to payment default by one or more ISO Debtors, the ISO shall transfer funds from the ISO Reserve Account to the ISO Clearing Account to clear it by close of banking business on that Payment Date pursuant to SABP 6.7.2.

SABP 6.5 **Use of the ISO Surplus Account**

SABP 6.5.1 **Establishment**

The ISO shall establish and maintain a bank account in accordance with this Protocol denominated the "ISO Surplus Account".

SABP 6.5.2 Other Funds in the ISO Surplus Account.

(a) Any amounts paid to the ISO in respect of acts or defaults giving rise to default interest referred to in SABP 6.10.5 or penalties referred to in SABP 3.1.1, to the extent that the ISO Tariff does not otherwise provide for the allocation of the proceeds of such penalties, shall be credited to the Surplus Account.

(b) The funds referred to in SABP 6.5.2(a) shall first be applied towards any expenses, loss or costs incurred by the ISO. Any excess will be credited to the Surplus Account pursuant to SABP 6.5.2(a).

SABP 6.5.3 Distribution of Funds

In the event that there are funds in the ISO Surplus Account in excess of an amount to be determined by the ISO Governing Board and noticed by the ISO to Market Participants, the amount of such excess will be distributed to Scheduling Coordinators using the same method of apportioning the refund as the method employed in apportioning the liability for the Grid Management Charge.

SABP 6.5.4 Trust

All amounts standing to the credit of the ISO Surplus Account will be held at all times on trust for Market Participants in accordance with this Protocol.

SABP 6.6 System Failure

SABP 6.6.1 At ISO Debtor's Bank

If any ISO Debtor becomes aware that a payment will not, or is unlikely to be, remitted to the ISO Bank by 10:00 am on the relevant Payment Date for any reason (including failure of the Fed-Wire or any computer system), it shall immediately notify the ISO, giving full details of the payment delay (including the reasons for the payment delay). The ISO Debtor shall make all reasonable efforts to remit payment as soon as possible, by an alternative method if necessary, to ensure that funds are received for value no later than 10:00 am on the Payment Date, or as soon as possible thereafter.

SABP 6.6.2 At the ISO's Bank

In the event of failure of any electronic transfer system affecting the ISO Bank, the ISO shall use reasonable efforts to establish alternative methods of remitting funds to the ISO Creditors' Settlement Accounts by close of banking business on that Payment Date, or as soon as possible thereafter. The ISO shall notify the ISO Debtors and the ISO Creditors of occurrence of the system failure and the alternative methods and anticipated time of payment.

SABP 6.7 Payment Default

Subject to SABP 6.8, if by 10:00 am on a Payment Date the ISO, in its reasonable opinion, believes that all or any part of any amount due to be remitted to the ISO Clearing Account by any Scheduling Coordinator will not or has not been remitted and there are insufficient funds in the relevant Scheduling Coordinator's ISO prepayment account (the amount of insufficiency being referred to as the "Default Amount"), the ISO shall take the following actions to enable the ISO Clearing Account to clear not later than the close of banking business on the relevant Payment Date:

SABP 6.7.1 **Enforcing the Security of a Defaulting Scheduling Coordinator**

Subject to SABP 6.8 the ISO shall make reasonable endeavors to enforce the defaulting Scheduling Coordinator's Security (if any) to the extent necessary to pay the Default Amount. If it is not practicable to obtain clear funds in time to effect payment to ISO Creditors on the same day the ISO shall proceed in accordance with SABP 6.7.2 or 6.7.4 as applicable.

SABP 6.7.2 **Use of ISO Reserve Account**

If there are funds standing to the credit of the ISO Reserve Account (including the proceeds of drawings under banking facilities described in SABP 2.2.5) the ISO shall debit the ISO Reserve Account with the Default Amount in order to clear the ISO Clearing Account and effect payment to the ISO Creditors.

SABP 6.7.3 **Action against a Defaulting Scheduling Coordinator**

The ISO shall as soon as possible after taking action under SABP 6.7.2 take any steps it deems appropriate against the defaulting Scheduling Coordinator to recover the Default Amount (and any default interest as set out in SABP 6.10.5) including enforcing any Security pursuant to Section 11.14 of the ISO Tariff, exercising its rights of recoupment or set-off pursuant to SABP 6.10.2 and/or bringing proceedings against the defaulting Scheduling Coordinator pursuant to Section 11.20.1 of the ISO Tariff.

SABP 6.7.4 **Reduction of Payments to ISO Creditors**

If there are insufficient funds standing to the credit of the ISO Reserve Account, the ISO shall reduce payments to ISO Creditors on that Payment Date pursuant to Section 11.16.1 of the ISO Tariff to the extent necessary to clear the ISO Clearing Account by the close of banking business on the Payment Date.

SABP 6.8 **Default to be Remedied Promptly**

In the event that the ISO reasonably believes that an outstanding amount which has not been paid by 10:00 am on the relevant Payment Date, is likely to be paid no later than close of banking business on the next Business Day then the ISO may, but shall not be obliged to, delay enforcing that ISO Debtor's Security or taking other measures to recover payment until after the close of banking business on the next Banking Day but default interest shall nonetheless accrue pursuant to SABP 6.10.5.

SABP 6.9 **Replenishing the ISO Reserve Account Following Payment Default**

If the ISO has debited the ISO Reserve Account as provided in SABP 6.7.2 then:

(a) If, after the ISO has debited the ISO Reserve Account on a Payment Date, the ISO Bank receives a remittance from an ISO Debtor which has not been (but should have been, if it had been received on a timely basis) credited to the ISO Clearing Account by 10:00 am on the Payment Date and which required the debiting of the ISO Reserve Account, such remittance shall be credited to the ISO Reserve Account.

(b) The proceeds of any enforcement of Security referred to in SABP 6.8.2 and/or amounts recovered under proceedings shall be credited to the ISO Reserve Account.

(c) If after taking reasonable action the ISO determines that the Default Amount (or any part) and/or default interest referred to in SABP 6.10.5 cannot be recovered, such amounts shall be deemed to be owing by those Market Participants who were ISO Creditors on the relevant Payment Date pro rata to the net payments they received on that Payment Date and shall be accounted for by way of a charge in the next Settlement Statements of those ISO Creditors. Such charge shall be credited to the Reserve Account.

SABP 6.10 Application of Funds Received

Amounts credited to the ISO Clearing Account in payment of a Default Amount (as set out in SABP 6.9(a)) or as a result of enforcing the defaulting ISO Debtor's Security shall be applied to the ISO Reserve Account pursuant to SABP 6.9 to reduce amounts outstanding under any ISO banking facilities used to fund the ISO Reserve Account on the relevant Payment Date and the balance (if any) shall be applied to reimburse pro rata any ISO Creditors whose payments were reduced pursuant to SABP 6.7.4.

SABP 6.10.1 Termination of SC Agreement and Limitation on Trading

The provisions of Section 2.2.4.5 and 2.2.7.3 of the ISO Tariff shall apply.

SABP 6.10.2 Set-Off

The ISO is authorized to recoup, set off and apply any amount to which any defaulting ISO Debtor is or will be entitled, in or towards the satisfaction of any of that ISO Debtor's debts arising under the ISO Settlement and billing process. Each ISO Creditor and each ISO Debtor expressly acknowledges that the oldest outstanding amounts will be settled first in the order of the creation of such debts.

SABP 6.10.3 Defaulting SCs and Eligible Customers

If the ISO intends to terminate the SC Agreement of a Scheduling Coordinator (the "Defaulting SC") pursuant to Section 2.2.4.5 of the ISO Tariff, the ISO shall give written notice to the UDC or UDCs on whose service territory the customers of that Defaulting SC are located and shall post such notification on the ISO Home Page pursuant to Section 2.2.4.6 of the ISO Tariff.

SABP 6.10.4 Order of Payments

The ISO shall apply payments received in respect of amounts owing to ISO Creditors to repay the relevant debts in the order of the creation of such debts.

SABP 6.10.5 Default Interest

Unless the ISO is able to enforce the Security (if any) provided by the defaulting ISO Debtor, such ISO Debtor shall pay interest on Default Amount at the ISO Default Interest Rate for the period from the relevant Payment Date to the date in which the payment is received by the ISO together with any related transaction costs incurred by the ISO pursuant to SABP 6.7.2.

SABP 6.10.6 Interest Accruing while Enforcing the Security

If the ISO has debited the Reserve Account as provided in SABP 6.7.1, 6.7.2 or 6.8 and it subsequently succeeds in enforcing the Security provided by the defaulting Scheduling Coordinator, the ISO shall be entitled to withdraw from such Security in addition to the Default Amount, all costs incurred and interest accrued to the ISO as a result of debiting the Reserve Account from the date of such debit to the date of enforcement of the said Security.

SABP 7 PAYMENT ERRORS

SABP 7.1 Overpayments

SABP 7.1.1 Notification

If an ISO Creditor receives an overpayment on any Payment Date, it shall notify the ISO of such overpayment in accordance with the provisions of Section 11.18.1 of the ISO Tariff.

SABP 7.1.2 Overpayment held on Trust

Until an ISO Creditor refunds the overpayment to the ISO, the ISO Creditor shall be deemed to hold the amount of such overpayment on trust for any ISO Creditor which may have been underpaid in consequence of such overpayment, pro rata to the amount of the underpayment.

SABP 7.1.3 Interest on Overpayment

(a) If an overpayment is repaid by an ISO Creditor in accordance with Section 11.18.1 of the ISO Tariff, the ISO shall be entitled to interest on the amount of the overpayment at the prime rate of the bank where the Settlement Account of the overpaid ISO Creditor is located from the date the overpayment was received to the time that the repayment is credited to the relevant ISO Account.

(b) If the overpayment (or any part of it) is not repaid by an ISO Creditor in accordance with Section 11.18.1 of the ISO Tariff, the ISO shall be entitled to interest on the amount of the overpayment at the ISO Default Interest Rate from the expiry of the two day period referred to in that Section until the repayment is credited to the relevant ISO Account and the ISO will be entitled to treat the overpayment (and any interest accruing thereon) as a Default Amount to which SABP 6.7 will apply.

SABP 7.1.4 Treatment of Amounts Outstanding as a Result of an Overpayment

The ISO shall apply the amount of any overpayment repaid (including interest received) to it under SABP 7.1.3 to credit any underpaid ISO Creditors pro rata to the amounts of their underpayments on the same day of receipt, or if not practicable, on the following Business Day.

SABP 8 COMMUNICATIONS

SABP 8.1 Method of Communication

Preliminary Settlement Statements and Final Settlement Statements will be published by the ISO on the WEnet. Invoices will be issued via EDI. Communications on a Payment Date relating to payment shall be made by the fastest practical means including by telephone. Methods of communication between the ISO and Market Participants may be varied by the ISO giving not less than 10 days notice to Market Participants on the WEnet.

SABP 8.2 Failure of Communications

The provisions of Section 11.23 of the ISO Tariff shall apply.

SABP 9 EMERGENCY PROCEDURES

SABP 9.1 Use of Estimated Data

In the event of an emergency or a failure of any of the ISO software or business systems, the ISO may use estimated Settlement Statements and invoices and may implement any temporary variation of the timing requirements relating to the Settlement and billing process contained in the ISO Tariff or this Protocol. Details of the variation and the method chosen to produce estimated data, Settlement Statements and invoices will be published on the ISO Home Page.

SABP 9.2 Payment of Estimated Statements and Invoices

When estimated Settlement Statements and invoices are issued by the ISO, payments between the ISO and Market Participants shall be made on an estimated basis and the necessary corrections shall be made by the ISO as soon as practicable. The corrections will be reflected as soon as practicable in later Settlement Statements and invoices issued by the ISO in the manner set forth in Section 11.5 of the ISO Tariff. Failure to make such estimated payments shall result in the same consequences as a failure to make actual payments under SABP.

SABP 9.3 Validation and Correction of Estimated Statements and Invoices

The ISO shall use its best efforts to verify the estimated data used under SABP 9.1 and to make the necessary corrections as soon as practicable. The corrections will be reflected as soon as practicable in later Settlement Statements and invoices issued by the ISO in the manner set forth in Section 11.5 of the ISO Tariff.

SABP 9.4 Estimated Statements to be Final

In the event that the ISO is of the opinion that, despite its best efforts, it is not possible for it to verify the estimated data because actual data is not reasonably expected to become available to the ISO in the foreseeable future, the ISO shall consult with the Market Participants in order to develop the most appropriate substitute data including using data provided by Market Participants. Following such determination of substitute data, the ISO shall send to the relevant Market Participants revised Settlement Statements and Invoices. The provisions of SABP 4.4.5 shall apply to payment of revised invoices issued in accordance with this SABP 9.4. Failure to make payments of such revised invoices shall result in the same consequences as a failure to make actual payments under SABP.

SABP 10 CONFIDENTIAL DATA

(a) The ISO shall implement and maintain a system of communication with Scheduling Coordinators to ensure compliance with Sections 11.22 and 20.3 of the ISO Tariff regarding access to confidential data and with Participating TOs pursuant to Section 26.3 of the Transmission Control Agreement.

(b) Access within the ISO to such data on ISO's communications systems, including databases and backup files, shall be strictly limited to authorized ISO personnel through the use of passwords and other appropriate means.

SABP 11 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

~~APPENDIX B~~

~~GRID OPERATIONS CHARGE COMPUTATION~~

~~B 1~~ **~~Purpose of charge~~**

~~The Grid Operations Charge is a charge which recovers redispatch costs incurred due to Intra-Zonal Congestion pursuant to Section 7.3.2 of the ISO Tariff. The Grid Operations Charge is paid by or charged to Scheduling Coordinators in order for the ISO to recover and properly redistribute the costs of adjusting the Balanced Schedules submitted by Scheduling Coordinators.~~

~~B 2~~ **~~Fundamental formulae~~**

~~B 2.1~~ **~~Payments to SCs with incremented schedules~~**

~~When it becomes necessary for the ISO to increase the output of a Scheduling Coordinator's Generating Unit$_i$ or System Resource$_i$ or reduce a Curtailable Demand$_i$ in order to relieve Congestion within a Zone, the ISO will pay the Scheduling Coordinator. The amount that ISO pays the Scheduling Coordinator$_j$ is the price specified in the Scheduling Coordinator's Day-Ahead or Hour-Ahead Adjustment Bid (or Imbalance Energy bid as appropriate) for the Generating Unit$_i$ or System Resource$_i$ or Curtailable Demand$_i$ multiplied by the quantity of Energy rescheduled. The formula for calculating the payment to Scheduling Coordinator$_j$ for each block$_b$ of Energy of its Adjustment Bid curve in Trading Interval$_t$ is:~~

$$INC_{bijt} = adjinc_{bijt} * \Delta inc_{bijt}$$

~~B 2.1.1~~ **~~Total Payment for Trading Interval~~**

~~The formula for calculating payment to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ has been increased or Curtailable Demand$_i$ reduced for all the relevant blocks$_b$ of Energy in the Adjustment Bid curve (or Imbalance Energy bid) of that Generating Unit or System Resource or Curtailable Demand in the same Trading Interval$_t$ is:~~

$$PayTI_{ijt} = \sum_b INC_{bijt}$$

~~B 2.2~~ **~~Charges to Scheduling Coordinators with decremented schedules~~**

~~When it becomes necessary for the ISO to decrease the output of a Scheduling Coordinator's Generating Unit$_i$ or System Resource$_i$ in order to relieve Congestion within a Zone, the ISO will make a charge to the Scheduling Coordinator. The amount that the ISO will charge Scheduling Coordinator$_j$ is the price specified in the Scheduling Coordinator's Day-Ahead or Hour-Ahead Adjustment Bid (or Imbalance Energy bid) for the Generating Unit$_i$ or System Resource$_i$ multiplied by the quantity of Energy rescheduled. The formula for calculating the~~

~~charge to Scheduling Coordinator~~$_j$ ~~for each block~~$_b$ ~~of Energy in its Adjustment Bid curve (or Imbalance Energy bid) in Trading Interval~~$_t$ ~~is:~~

$$DEC_{bijt} = adjdec_{bijt} * \Delta dec_{bijt}$$

~~B 2.2.1 Total Charge for Trading Interval~~

~~The formula for calculating the charge to Scheduling Coordinator~~$_j$ ~~whose Generating Unit~~$_i$ ~~or System Resource~~$_i$ ~~has been decreased for all the relevant blocks~~$_b$ ~~of Energy in the Adjustment Bid curve (or Imbalance Energy bid) of that Generating Unit or System Resource in the same Trading Interval~~$_t$ ~~is:~~

$$ChargeTI_{ijt} = \sum_b DEC_{bijt}$$

~~B 2.3 Not Used~~

~~B 2.4 Net ISO redispatch costs~~

~~The Trading Interval net redispatch cost encountered by ISO to relieve Intra-Zonal Congestion is the sum of the amounts paid by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased or Curtailable Demand was decreased during the Trading Interval less the sum of the amounts received by the ISO from those Scheduling Coordinators whose Generating Units or System Resource were decreased during the Trading Interval. The fundamental formula for calculating the net redispatch cost is:~~

$$REDISP_{CONGt} = \sum_j PayTI_{ijt} - \sum_j ChargeTI_{ijt}$$

~~Note that~~ $REDISP_{CONGt}$ ~~can be either positive or negative. This means that it is possible for the ISO to generate either a net cost or a net income, for any given Trading Interval. In the event the ISO does not make use of equal amounts of incremental and decremental dispatched MWHs, then the net redispatch cost becomes the sum of the amounts paid (or charged) by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased (or decreased) or Curtailable Demand was decreased (or increased) during the Trading Interval less the sum of the amounts received by the ISO from Scheduling Coordinators through the Imbalance Energy Market.~~

~~B 2.5 Grid Operations Price~~

~~The grid operations price is the Trading Interval rate used by the ISO to apportion net Trading Interval redispatch costs to Scheduling Coordinators within the Zone with Intra-Zonal Congestion. The grid operations price is calculated using the following formula:~~

$$GOP_t = \frac{REDISP_{CONG_t}}{\sum_j QCharge_{jt} + \sum_j Export_{jt}}$$

~~**B 2.6 Grid Operations Charge**~~

~~The Grid Operations Charge is the vehicle by which the ISO recovers the net redispatch costs. It is allocated to each Scheduling Coordinator in proportion to the Scheduling Coordinator's Demand in the Zone with Intra-Zonal Congestion and Exports from the Zone with Intra-Zonal Congestion. The formula for calculating the Grid Operations Charge for Scheduling Coordinator$_j$ in Trading Interval$_t$ is:~~

$$\cancel{GOC_{jt} = GOP_t * \left(QCharge_{jt} + EXPORT_{jt}\right)}$$

~~**B 3 Meaning of terms of formulae**~~

~~**B 3.1 INC$_{bijt}$ - $**~~

~~The payment from the ISO due to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ is increased or Curtailable Load$_i$ is reduced within a block$_b$ of Energy in its Adjustment Bid curve (or Imbalance Energy bid) in Trading Interval$_t$ in order to relieve Intra-Zonal Congestion.~~

~~**B 3.2 adjinc$_{bijt}$ - $/MWh**~~

~~The incremental cost for the rescheduled Generating Unit$_i$ or System Resource$_i$ or Curtailable Load$_i$ taken from the relevant block$_b$ of Energy in the Day-Ahead or Hour-Ahead Adjustment Bid curve (or Imbalance Energy bid) submitted by the Scheduling Coordinator$_j$ for the Trading Interval$_t$.~~

~~**B 3.3 ∆incbijt - MW**~~

~~The amount by which the Generating Unit$_i$ or System Resource$_i$ or Curtailable Load$_i$ of Scheduling Coordinator$_j$ for Trading Interval$_t$ is increased by the ISO within the relevant block$_b$ of Energy in its Adjustment Bid curve (or Imbalance Energy bid).~~

~~**B 3.4 PayTI$_{jit}$ - $**~~

~~The Trading Interval payment to Scheduling Coordinator$_j$ whose Generating Unit$_i$ has been increased or System Resource$_i$ or Curtailable Load$_i$ reduced in Trading Interval$_t$ of the Trading Day.~~

~~**B 3.5 DEC$_{bijt}$ - $**~~

~~The charge to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ is decreased for Trading Interval$_t$ within a block$_b$ of Energy in its Adjustment Bid curve (or Imbalance Energy resource).~~

~~B 3.6~~ **~~adjdec$_{bijt}$ - \$/MWh~~**

~~The decremental cost for the rescheduled Generating Unit$_i$ or System Resource$_i$ taken from the relevant block$_b$ of Energy of the Day-Ahead or Hour-Ahead Adjustment Bid curve (or Imbalance Energy resource) submitted by Scheduling Coordinator$_j$ for the Trading Interval$_t$.~~

~~B 3.7~~ **~~Δdec$_{bijt}$ - MW~~**

~~The amount by which the Generating Unit$_i$ or System Resource$_i$ of Scheduling Coordinator$_j$ for Trading Interval$_t$ is decreased by ISO within the relevant block$_b$ of Energy of its Adjustment Bid curve (or Imbalance Energy resource).~~

~~B 3.8~~ **~~ChargeTI$_{ijt}$ - \$~~**

~~The Trading Interval charge to Scheduling Coordinator$_j$ whose Generating Unit$_i$ or System Resource$_i$ has been decreased in Trading Interval$_t$ of the Trading Day.~~

~~B 3.9~~ **~~Not Used~~**

~~B 3.10~~ **~~Not Used~~**

~~B 3.10.1~~ **~~Not Used~~**

~~B 3.10.2~~ **~~P$_{xt}$ - \$/MWh~~**

~~The zonal Hourly Ex Post Price, for Uninstructed Imbalance Energy, for Trading Interval t in Zone x.~~

~~B 3.11~~ **~~REDISP$_{CONGt}$ - \$~~**

~~The Trading Interval net cost to ISO to redispatch in order to relieve Intra-Zonal Congestion during Trading Interval$_t$.~~

~~B 3.12~~ **~~GOP$_t$ - \$/MWh~~**

~~The Trading Interval grid operations price for Trading Interval$_t$ used by the ISO to recover the costs of redispatch for Intra-Zonal Congestion Management.~~

~~B 3.13~~ **~~GOC$_{jt}$ - \$~~**

~~The Trading Interval Grid Operations Charge by the ISO for Trading Interval$_t$ for Scheduling Coordinator$_j$ in the relevant Zone with Intra-Zonal Congestion.~~

~~B 3.14~~ **~~QCHARGE$_{jt}$ – MWh~~**

~~The Trading Interval metered Demand within a Zone for Trading Interval$_t$ for Scheduling Coordinator$_j$ whose Grid Operations Charge is being calculated.~~

~~B 3.15~~ **~~EXPORT$_{jt}$ – MWh~~**

~~The total Energy for Trading Interval$_t$ exported from the Zone to a neighboring Control Area by Scheduling Coordinator$_j$.~~

APPENDIX C. SETTLEMENT OF ANCILLARY SERVICES

C.1. General Information

For each operating hour, the ISO must ensure that there are sufficient Ancillary Services available to maintain the reliability of the ISO Controlled Grid consistent with WSCC and NERC criteria. ISO Ancillary Services include Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve. Each of these services is settled separately.

C.1.1. Terms

Any reference to the term "Regulation" as used in Appendix C shall be read as referring to "Regulation Up" or "Regulation Down".

The term “Region” or “Regional” as used in Appendix C shall refer to the “Ancillary Service Region” as defined in the Master Definitions Supplement, Appendix A.

The term “Metered Demand” as used in Appendix C shall refer to metered load and real-time exports.

Ancillary Service Self-Provision

Scheduling Coordinators may chose to self-provide Ancillary Services to (i) reduce their own Net Ancillary Service Obligation and (ii) use the Excess Self-Provision to reduce other SC’s Net Ancillary Service Obligation if such Excess Self-Provisions are Qualified.

Gross Ancillary Service Obligation

The Gross Ancillary Service Obligation for each service for each hour for each Scheduling Coordinator is the amount of Ancillary Services that it needs to secure either by self-provision or by ISO-provision. Each Scheduling Coordinator’s obligation to pay Ancillary Service charges is based on metered demand adjusted for on-demand obligation and Inter-SC Ancillary Services trades.

Gross Ancillary Service Requirement

The Gross Ancillary Service Requirement for each service for each hour in each region in each of the market, i.e. the Day-Ahead Market and the Hour-Ahead Market, is the amount of capacity that needs to be secured by the ISO either through procurement or self-provision.

Net Ancillary Service Obligation

The Net Ancillary Service Obligation for each service for each hour for each Scheduling Coordinator is its Gross Ancillary Service Obligation minus the amount of Self-Provision accepted by the ISO in the Day-Ahead or the Hour-Ahead Market. The Net Ancillary Service Obligation is the basis for billing a given Ancillary Service.

Net Ancillary Service Requirement

The Net Ancillary Service Requirement for each Ancillary Service for each hour in each region in each market is the Gross Ancillary Service Requirement minus Qualified Ancilary Service Self-Provision.

Qualified Ancillary Service Self-Provision

Qualified Ancillary Service Self-Provision is the amount of self-provision that has been used to reduce the ISO's Gross Ancillary Service Requirement. In other words, it has been used to determine the Net Ancillary Service Requirement in either the Day-Ahead Market or the Hour-Ahead Market.

Qualified Excess Ancillary Service Self-Provision

The amount of self-provision that exceeds the Gross Ancillary Service Obligation of the Scheduling Coordinator is referred to as Excess Ancillary Service Self-Provision. Qualified Excess Ancillary Services Self-Provision will be compensed if it is used by the ISO to reduce the Gross Ancillary Service Requirement.

C.1.2. Payments

The ISO will purchase Ancillary Services for each Settlement Period in both the Day-Ahead and Hour-Ahead Markets. Separate payments will be calculated for each service for each Settlement Period and in each market for each resource providing Ancillary Services. The prices used to determine the payments are the Ancillary Service Marginal Prices, as determined by SCUC. The SCUC prices reflect a simultaneous procurement of Energy and Ancillary Services at least cost and take into account the substitutability of services.

C.1.3. Charges

The Ancillary Service Charges allocate the costs of purchasing Ancillary Services in the Day-Ahead and Hour-Ahead Markets to Scheduling Coordinators according to their share of the metered Load (for Regulation) or metered Demand (for Spinning and Non-Spinning Reserves).

Scheduling Coordinators shall be paid for their Qualifiied Excess Ancillary Services Self-Provision.

The user rates that are used in calculating Ancillary Service charges are based on the cost of meeting each Ancillary Service requirement.

C.1.4. Neutrality

Due to the difference between the basis for payment and charge of Ancillary Services, there is a need for a neutrality adjustment. Specifically, payment for the procurement of Ancillary Services is based on the ISO Demand Forecast, whereas the charge methodology is based on Metered Demand. Since the ISO Demand Forecast may be different than Metered Demand, there will be a difference, in total, between the two calculations and a need for a neutrality adjustment. The neutrality imbalance for each Ancillary Service will be allocated to all Scheduling Coordinators based on Demand (for Regulation) or Demand (for Spinning and Non-Spinning Reserve service.)

C.2. Fundamental formulas

C.2.1. ISO payments to Scheduling Coordinators

C.2.1.1. Day-Ahead Market

C.2.1.1.1. Regulation

When the ISO purchases Regulation in the Day-Ahead Market, Scheduling Coordinators for Generating Units, System Units, and System Resources that provide this capacity will receive payments for each Settlement Period of the Day-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over a given Settlement Period will be the total quantity of Regulation capacity provided times the applicable Ancillary Service Marginal Pricefor that Settlement Period. in that Ancillary Service Region. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. Regulation Up and Regulation Down payments shall be calculated separately. The payment for Scheduling Coordinator *j* for providing Regulation Up capacity from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCUpPayDA_{ijxt} = AGCUpQDA_{ijxt} \times PAGCUpDA_{jxt} - AGCUpCCDA_{ijxt}$$

where $AGCUpCCDA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for Regulation Up in the Day-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$$AGCUpCCDA_{ijxt} = AGCUpQDA_{ijxt} \times PCCDA_{xt}$$

This Congestion Charge is booked as receivable in the FTR balancing account as Congestion Revenue.

The payment for Scheduling Coordinator *j* for providing Regulation Down capacity from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCDownPayDA_{ijxt} = AGCDownQDA_{ijxt} \times PAGCDownDA_{xt}$$

The total Regulation Up payment to each Scheduling Coordinator for a given Settlement Period in the Day-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period. The payment for Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t is calculated as follows:

$$AGCUpPayTotalDA_{jxt} = \sum_{i} AGCUpPayDA_{ijxt}$$

The total Regulation Down payment to each Scheduling Coordinator for a given Settlement Period in the Day-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCDownPayTotalDA_{jxt} = \sum_{i} AGCDownPayDA_{ijxt}$$

C.2.1.1.2. Spinning Reserve

When ISO purchases Spinning Reserve in the Day-Ahead Market, Scheduling Coordinators for Generating Units, System Units, and System Resources that provide this capacity will receive payments for each Settlement Period of the Day-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over a given Settlement Period will be the total quantity of Spinning Reserve capacity provided times the applicable Ancillary Service Marginal Price adjusted for Congestion Charges on interties if applicable for that Settlement Period in that Ancillary Service Region. The required Spinning Reserve capacity is defined in the Ancillary Services Requirements Protocol. The payment for Scheduling Coordinator *j* for providing Spinning Reserve from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$SpinPayDA_{ijxt} = SpinQDA_{ijxt} \times PSpinDA_{xt} - SpinCCDA_{ijxt}$$

where $SpinCCDA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for Spinning Reserve in the Day-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$$SpinCCDA_{xt} = SpinQDA_{ijxt} \times PCCDA_{xt}$$

This Congestion Charge is booked as receivable in the FTR balancing account as Congestion Revenue.

The total Spinning Reserve payment to each Scheduling Coordinator for a given Settlement Period in the Day-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$SpinPayTotalDA_{jxt} = \sum_{i} SpinPayDA_{ijxt}$$

C.2.1.1.3. Non-Spinning Reserve

When the ISO purchases Non-Spinning Reserve in the Day-Ahead Market, Scheduling Coordinators for Generating Units, System Units, Dispatchable Loads, and System Resources that provide this capacity will receive payments for each Settlement Period of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over a given

Settlement Period will be the total quantity of Non-Spinning Reserve capacity provided times the applicable Ancillary Service Marginal Price adjusted for Congestion Charges on interties if applicable for that Settlement Period in that Ancillary Service Region. The required Non-Spinning Reserve capacity is defined in the Ancillary Services Requirements Protocol. The payment for Scheduling Coordinator *j* for providing Non-Spinning Reserve capacity from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$NonSpinPayDA_{ijxt} = NonSpinQDA_{ijxt} \times PNonSpinDA_{xt} - NonSpinCCDA_{ijxt}$$

where $NonSpinCCDA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for Non-Spinning Reserve in the Day-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$$NonSpinCCDA_{ijxt} = NonSpinQDA_{ijxt} \times PCCDA_{xt}$$

This Congestion Charge is booked as a receivable in the FTR Balancing Account as Congestion Revenue.

The total Non-Spinning Reserve payment to each Scheduling Coordinator for a given Settlement Period in the Day-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$NonSpinPayTotalDA_{jxt} = \sum_{i} NonSpinPayDA_{ijxt}$$

C 2.1.2 Hour-Ahead Market

C.2.1.1.4. Regulation

When the ISO purchases Regulation in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, System Units, and System Resources that provide this capacity will receive payment for the Settlement Period of the Hour-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over the Settlement Period will be the total quantity of Regulation capacity provided times the applicable Ancillary Service Marginal Price for that Settlement Period in that Ancillary Service Region. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. Regulation Up and Regulation Down payments shall be calculated separately. The payment for Scheduling Coordinator *j* for providing Regulation Up capacity from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCUpPayHA_{ijxt} = AGCUpQIHA_{ijxt} \times PAGCUpHA_{xt} - AGCUpCCHA_{ijxt}$$

where $AGCUpCCHA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for Regulation Up in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$AGCUpCCHA_{ijxt} = AGCUpQIHA_{ijxt} \times PCCHA_{xt}$

This Congestion Charge is booked as receivable in the FTR balancing account as Congestion Revenue.

The payment for Scheduling Coordinator *j* for providing Regulation Down from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$AGCDownPayHA_{ijxt} = AGCDownQIHA_{ijxt} \times PAGCDownHA_{xt}$

When a Scheduling Coordinator buys back, in the Hour-Ahead Market, Regulation capacity which it sold or self-provided to the ISO in the Day-Ahead Market, the buy-back charge will be the total quantity of Regulation capacity bought back times the greater of the Day-Ahead Ancillary Service Marginal Price and the Hour-Ahead Ancillary Service Marginal Price as applicable for that Settlement Period in that Ancillary Service Region. The payment to the ISO from Scheduling Coordinator *j* to buy back Regulation Up from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$AGCUpReceiveHA_{ijxt} = AGCUpQDHA_{ijxt} \times \max(PAGCUpDA_{xt}, PAGCUpHA_{xt}) - AGCUpCPHA_{ijxt}$

where $AGCUpCPHA_{ijxt}$ is the Congestion Payment to Scheduling Coordinator *j* for Regulation Up in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$AGCUpCPHA_{ijxt} = AGCUpQDHA_{ijxt} \times PCCHA_{xt}$

This Congestion payment is credited to the FTR Balancing Account as Congestion Revenue.

The payment to the ISO from Scheduling Coordinator *j* to buy back Regulation Down from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$AGCDownReceiveHA_{ijxt} = AGCDownQDHA_{ijxt} \times \max(PAGCDownDA_{xt}, PAGCDownHA_{xt})$

The total Regulation payment for the Settlement Period of the Hour-Ahead Market to each Scheduling Coordinator for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Regulation bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Settlement Period on behalf of resources located in the Ancillary Service Region. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCUpPayTotalHA_{jxt} = \sum_i AGCUpPayHA_{ijxt} - \sum_i AGCUpReceiveHA_{ijxt}$$

$$AGCDownPayTotalHA_{jxt} = \sum_i AGCDownPayHA_{ijxt} - \sum_i AGCDownReceiveHA_{ijxt}$$

C.2.1.1.5. Spinning Reserve

When the ISO purchases Spinning Reserve in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, System Units, and System Resources that provide this capacity will receive payments for the Settlement Period of the Hour-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over the Settlement Period will be the total quantity of Spinning Reserve capacity provided times the applicable Ancillary Service Marginal Price adjusted for Congestion Charges on interties if applicable for that Settlement Period in that Ancillary Service Region. The payment for Scheduling Coordinator *j* for providing Spinning Reserve capacity from resource i in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$SpinPayHA_{ijxt} = SpinQIHA_{ijxt} \times PSpinHA_{xt} - SpinCCHA_{ijxt}$

where $SpinCCHA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for Spinning Reserve in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$SpinCCHA_{ijxt} = SpinQIHA_{ijxt} \times PCCHA_{xt}$

This Congestion Charge is booked as a receivable in the FTR Balancing Account as Congestion Revenue.

When a Scheduling Coordinator buys back in the Hour-Ahead Market Spinning Reserve which it sold or self-provided to the ISO in the Day-Ahead Market, the buy-back charge will be the total quantity of Spinning Reserve capacity bought back times the greater of the Regional Day-Ahead Ancillary Service Marginal Price and the Regional Hour-Ahead Ancillary Service Marginal Price as applicable for that Settlement Period in that Ancillary Service Region. The payment to the ISO from Scheduling Coordinator *j* to buy back Spinning Reserve from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$SpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} \times \max(PSpinDA_{xy}, PSpinHA_{xt}) - SpinCPHA_{ijxt}$

where $SpinCPHA_{ijxt}$ is the Congestion Payment to Scheduling Coordinator *j* for Spinning Reserve in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$SpinCPHA_{ijxt} = SpinQDHA_{ijxt} \times PCCHA_{xt}$

This Congestion payment is credited to the FTR Balancing Account as Congestion Revenue.

The total Spinning Reserve payment to each Scheduling Coordinator for the Settlement Period of the Hour-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Settlement Period on behalf of resources located in the Ancillary Service Region. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$SpinPayTotalHA_{jxt} = \sum_i SpinPayHA_{ijxt} - \sum_i Spin\,\mathrm{Re}\,ceiveHA_{ijxt}$$

C.2.1.1.6. Non-Spinning Reserve

When the ISO purchases Non-Spinning Reserve in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, System Units, Dispatchable Loads, and System Resources that provide this capacity will receive payment for the Settlement Period of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over the Settlement Period will be the total quantity of Non-Spinning Reserve capacity provided times the applicable Ancillary Service Marginal Price adjusted for Congestion Charges on interties if applicable for that Settlement Period in that Ancillary Service Region. This payment for Scheduling Coordinator *j* for providing Non-Spinning Reserve capacity from a resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$NonSpinPayHA_{ijxt} = NonSpinQIHA_{ijxt} \times PNonSpinHA_{xt} - NonSpinCCHA_{ijxt}$

where $NonSpinCCHA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for providing Non-Spinning Reserve in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$NonSpinCCHA_{ijxt} = NonSpinQIHA_{ijxt} \times PCCHA_{xt}$

This Congestion Charge is booked as a receivable in the FTR Balancing Account as Congestion Revenue.

When a Scheduling Coordinator buys back in the Hour-Ahead Market Non-Spinning Reserve which it sold or self-provided to the ISO in the Day-Ahead Market, the buy-back charge will be the total quantity of Non-Spinning Reserve capacity bought back times the greater of the Regional Day-Ahead Ancillary Service Marginal Price and the Regional Hour-Ahead Ancillary Service Marginal Price as applicable for that Settlement Period in that Ancillary Service Region.

This payment to the ISO from Scheduling Coordinator *j* to buy back Non-Spinning Reserve from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$NonSpinReceiveHA_{ijxt} = NonSpinQDHA_{ijxt} \times \max(PNonSpinDA_{xy}, PNonSpinHA_{xt}) – NonSpinCPHA_{ijxt}$

where $NonSpinCPHA_{ijxt}$ is the Congestion Payment to Scheduling Coordinator *j* for Non-Spinning Reserve in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$NonSpinCPHA_{ijxt} = NonSpinQDHA_{ijxt} \times PCCHA_{xt}$

This Congestion payment is credited to the FTR Balancing Account as Congestion Revenue.

The total Non-Spinning Reserve payment to each Scheduling Coordinator for the Settlement Period of the Hour-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Non-Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Settlement Period on behalf of resources located in the Ancillary Service Region. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$NonSpinPayTotalHA_{jxt} = \sum_i NonSpinPayHA_{ijxt} - \sum_i NonSpin\mathrm{Re}\,ceiveHA_{ijxt}$$

C.2.2. ISO Allocation of Charges toScheduling Coordinators

C.2.2.1. Regulation Up

The ISO will charge the total cost of procuring Regulation in the Day-Ahead and Hour-Ahead Markets, through the application of a charge to each Scheduling Coordinator for each Settlement Period at the ISO Control Area level. This charge will be computed by multiplying the Regulation user rate for the Settlement Period by the Scheduling Coordinator's Net Regulation Obligation for the same period.

The Regulation user rate is calculated by dividing the total procurement cost for the Net Regulation Capacity Requirement in all Ancillary Service Regions, for the Settlement Period, by the total Net Regulation Requirement for the Settlement Period in all Ancillary Service Regions. Regulation Up and Regulation Down payments shall be calculated separately.

The Regulation Up user rate for Settlement Period t is calculated as follows:

$$AGCUpRate_t = \frac{AGCUpPayNetReqDA_t + AGCUpPayNetReqHA_t}{AGCUpNetReqDA_t + AGCUpNetReqHA_t}$$

where $AGCUpNetReqDA_t$ is the Net Regulation Up Requirement for the Settlement Period t in the Day-Ahead Market for the ISO Control Area. It is the sum of all the Regional Net Regulation Up Requirement in the Day-Ahead Market as follows:

$$AGCUpNetReqDA_t = \sum_y AGCUpNetReqDA_{yt}$$

$AGCUpPayNetReqDA_t$ is the cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Day-Ahead Market in all the Regions. It is calculated as follows:

$$AGCUpPayNetReqDA_t = \sum_y AGCUpPayNetReqDA_{yt}$$

$AGCUpPayNetReqDA_{yt}$ is the cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Day-Ahead Market in Region y. It is calculated as follows:

$$AGCUpPayNetReqDA_{yt} = AGCUpNetReqDA_{yt} \times PAGCUpDA_{yt}$$

where:

$AGCUpNetReqDA_{yt}$ is the Net Regulation Up Requirement for the Settlement Period t in the Day-Ahead Market for Region y.

$PAGCUpDA_{yt}$ is the Ancillary Service Marginal Price for Regulation Up for the Settlement Period t incurred in the Day-Ahead Market for Region y.

$AGCUpNetReqHA_t$ is the Net Regulation Up Requirement for the Settlement Period t in the Hour-Ahead Market for all the Regions. It is the sum of all the Regional Net Regulation Up Requirement as follows:

$$AGCUpNetReqHA_t = \sum_z AGCUpNetReqHA_{zt}$$

$AGCUpPayNetReqHA_t$ is the cost of Regulation Up procurement to meet net Regulation Up Requirement for the Settlement Period t incurred in the Hour-Ahead Market in all the Regions. It is calculated as follows:

$$AGCUpPayNetReqHA_t = \sum_z AGCUpPayNetReqHA_{zt}$$

$AGCUpPayNetReqHA_{zt}$ is the cost of Regulation Up procurement to meet net Regulation Up Requirement for the Settlement Period t incurred in the Hour-Ahead Market in Region z. It is calculated as follows:

$$AGCUpPayNetReqDA_{zt} = AGCUpNetReqHA_{zt} \times PAGCUpHA_{zt} - AGCUpReceiveHA_{zt}$$

where:

$AGCUpNetReqHA_{zt}$ is the total incremental Net Requirement of Regulation Up for the Settlement Period *t* in the Hour-Ahead Market for Region z.

$PAGCUpHA_{zt}$ is the Ancillary Service Marginal Price for Regulation Up for the Settlement Period *t* incurred in the Hour-Ahead Market for Region z.

$AGCUpReceiveHA_{zt}$ is the Total charges for Hour-Ahead Buyback of Regulation Up for the Settlement Period t for Region z.

The Regulation Up charge for Scheduling Coordinator *j* for Settlement Period *t* is calculated as follows:

$$AGCUpChg_{jt} = AGCUpNetOblig_{jt} \times AGCUpRate_{t}$$

$AGCUpNetOblig_{jt}$ is the Net Regulation Up Obligation for Scheduling Coordinator *j* for Settlement Period *t*. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Regulation Up.

$$AGCUpNetOblig_{jt} = AGCUpGrossOblig_{jt} - AGCUpQualifySelf_{jt}$$

where:

$AGCUpGrossOblig_{jt}$ is the gross Regulation Up Obligation for Scheduling Coordinator *j* for Settlement Period *t*.

$AGCUpQualifySelf_{jt}$ is the Qualified Self-Provision of Regulation Up for Scheduling Coordinator *j* for Settlement Period *t*.

$$AGCUpQualifySelf_{jt} = AGCUpQualifySelfDA_{jt} + AGCUpQualifySelfHA_{jt}$$

$AGCUpQualifySelfDA_{jt}$ = The Qualified Day-Ahead Self-Provision of Regulation Up for Scheduling Coordinator *j* for Settlement Period *t*.

$$AGCUpQualifySelfDA_{jt} = \sum_{y} AGCUpQualifySelfDA_{jyt}$$

$AGCUpQualifySelfHA_{jt}$ = The Qualified Hour-Ahead Self-Provision of Regulation Up for Scheduling Coordinator *j* for Settlement Period *t*.

$$AGCUpQualifySelfHA_{jt} = \sum_{z} AGCUpQualifySelfHA_{jzt}$$

where

$AGCUpQualifySelfDA_{jyt}$ is the Qualified Day-Ahead Self-Provision of Regulation Up for Scheduling Coordinator *j* in Region *y* for Settlement Period *t*.

$AGCUpQualifySelfHA_{jzt}$ is the Qualified Hour-Ahead Self-Provision of Regulation Up for Scheduling Coordinator *j* in Region *z* for Settlement Period *t*.

The ISO will charge each Scheduling Coordinator a Regulation Up Neutrality Adjustment Charge for each Settlement Period according to Demand.

$$AGCUpNeutraAdjChg_{jt} = MeteredLoad_{jt} \times AGCUpNeutraAdjRate_t$$

where:

$AGCUpNeutraAdjChg_{jt}$ is the Regulation Up Neutrality Adjustment Charge to Scheduling Coordinator *j* for Settlement Period *t*.

$MeteredLoad_{jt}$ is the Demand of Scheduling Coordinator *j* for Settlement Period *t*.

$AGCUpNeutraAdjRate_t$ is the Regulation Up Neutrality Adjustment Rate for Settlement Period *t*. The rate is the difference between the total amount of charge and the total amount of payment for the service divided by the total Demand of the ISO control area as follows.

$$AGCUpNeutraAdjRate_t = \frac{AGCUpChgTotal_t - AGCUpPayTotal_t - AGCUpCCTotal_t}{MeteredLoadTotal_t}$$

where:

$AGCUpChgTotal_t$ is the total amount of charges collected by the ISO from Scheduling Coordinators for provision of Regulation Up Service for the Settlement Period *t*.

$$AGCUpChgTotal_t = \sum_j AGCUpChg_{jt}$$

$AGCUpPayTotal_t$ is the total amount of payment from the ISO to Scheduling Coordinators for procuring Regulation Up Service for the Settlement Period *t* in both the Day-Ahead and the Hour-Ahead Markets.

$$AGCUpPayTotal_t = \sum_j \sum_x \left(AGCUpPayTotalDA_{jxt} + AGCUpPayTotalHA_{jxt}\right)$$

$AGCUpCCTotal_t$ is the total amount of Congestion charge incurred to the ISO for procuring Regulation Up over Congested interties for Settlement Period *t*. This amount shall be transferred into the FTR Balancing Account to balance the Congestion charge receivables booked in the Day-Ahead Market and the Hour-Ahead Market when Regulation Up is procured.

$$AGCUpCCTotal_t = \sum_j \sum_x \sum_i AGCUpCCDA_{ijxt} + \sum_j \sum_x \sum_i \left(AGCUpCCHA_{ijxt} - AGCUpCPHA_{ijxt}\right)$$

C.2.2.2. Regulation Down

The Regulation Down user rate in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCDownRate_t = \frac{AGCDownPayNetReqDA_t + AGCDownPayNetReqHA_t}{AGCDownNetReqDA_t + AGCDownNetReqHA_t}$$

—

where:

$AGCUpNetReqDA_t$ is the Net Regulation Down Requirement for the Settlement Period *t* in the Day-Ahead Market. It is the sum of all the Regional Net Regulation Down Requirement as follows:

$$AGCDownNetReqDA_t = \sum_y AGCDownNetReqDA_{yt}$$

$AGCDownPayNetReqDA_t$ is the cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period *t* incurred in the Day-Ahead Market. It is calculated as follows:

$$AGCDownPayNetReqDA_t = \sum_y AGCDownPayNetReqDA_{yt}$$

$AGCDownPayNetReqDA_{yt}$ is the cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period *t* incurred in the Day-Ahead Market in Region *y*. It is calculated as follows:

$$AGCDownPayNet\,\mathrm{Re}\,qDA_{yt} = AGCDownNet\,\mathrm{Re}\,qDA_{yt} \times PAGCDownDA_{yt}$$

where:

$AGCDownNetReqDA_{yt}$ is the Net Regulation Down Requirement for the Settlement Period *t* in the Day-Ahead Market for Region *y*.

$PAGCDownDA_{yt}$ is the Ancillary Service Marginal Price for Regulation Down for the Settlement Period *t* incurred in the Day-Ahead Market for Region *y*.

$AGCDownNetReqHA_t$ is the Net Regulation Down Requirement for the Settlement Period *t* in the Hour-Ahead Market. It is the sum of all the Regional Net Regulation Down Requirement as follows:

$$AGCDownNetReqHA_t = \sum_z AGCDownNetReqHA_{zt}$$

$AGCDownPayNetReqHA_t$ is the cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market. It is calculated as follows:

$$AGCDownPayNetReqHA_t = \sum_z AGCDownPayNetReqHA_{zt}$$

$AGCDownPayNetReqHA_{zt}$ is the cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period t incurred in the Hour-Ahead Market in Region z. It is calculated as follows:

$$AGCDownPayNet\,\mathrm{Re}\,qDA_{zt} = AGCDownNet\,\mathrm{Re}\,qHA_{zt} \times PAGCDownHA_{zt} - AGCDown\,\mathrm{Re}$$

where:

$AGCDownNetReqHA_{zt}$ is the total incremental Net Requirement of Regulation Down for the Settlement Period t in the Hour-Ahead Market for Region z.

$PAGCDownHA_{zt}$ is the Ancillary Service Marginal Price for Regulation Down for the Settlement Period t incurred in the Hour-Ahead Market for Region z.

$AGCDownReceiveHA_{zt}$ is the total charges for Hour-Ahead Buyback of Regulation Down for the Settlement Period t for Region z.

The Regulation Down capacity charge for Scheduling Coordinator j for Settlement Period t is calculated as follows:

$$AGCDownChg_{jt} = AGCDownNetOblig_{jt} \times AGCDownRate_t$$

$AGCDownNetOblig_{jt}$ is the The Net Regulation Down Obligation for Scheduling Coordinator j for Settlement Period t. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Regulation Down.

$$AGCDownNetOblig_{jt} = AGCDownGrossOblig_{jt} - AGCDownQualifySelf_{jt}$$

where:

$AGCDownGrossOblig_{jt}$ is the The Gross Regulation Down Obligation for Scheduling Coordinator j for Settlement Period t.

$AGCDownQualifySelf_{jt}$ is the The Qualified Self-Provision of Regulation Down for Scheduling Coordinator j for Settlement Period t.

$$AGCDownQualifySelf_{jt} = AGCDownQualifySelfDA_{jt} + AGCDownQualifySelfHA_{jt}$$

$AGCDownQualifySelfDA_{jt}$ is the The Qualified Day-Ahead Self-Provision of Regulation Down for Scheduling Coordinator j for Settlement Period t.

$$AGCDownQualifySelfDA_{jt} = \sum_{y} AGCDownQualifySelfDA_{jyt}$$

$AGCDownQualifySelfHA_{jt}$ is the The Qualified Hour-Ahead Self-Provision of Regulation Down for Scheduling Coordinator j for Settlement Period t.

$$AGCDownQualifySelfHA_{jt} = \sum_{z} AGCDownQualifySelfHA_{jzt}$$

where:

$AGCDownQualifySelfDA_{jyt}$ is the The Qualified Day-Ahead Self-Provision of Regulation Down for Scheduling Coordinator *j* in Region *y* for Settlement Period *t*.

$AGCDownQualifySelfHA_{jzt}$ is the Qualified Hour-Ahead Self-Provision of Regulation Down for Scheduling Coordinator *j* in Region *z* for Settlement Period *t*.

The ISO will charge each Scheduling Coordinator a Regulation Down Neutrality Adjustment Charge for each Settlement Period according to Demand.

$$AGCDownNeutraAdjChg_{jt} = MeteredLoad_{jt} \times AGCDownNeutraAdjRate_{t}$$

where:

$AGCDownNeutraAdjChg_{jt}$ is the Regulation Down Neutrality Adjustment Charge to Scheduling Coordinator *j* for Settlement Period *t*.

$MeteredLoad_{jt}$ is the Demand of Scheduling Coordinator j for Settlement Period *t*.

$AGCDownNeutraAdjRate_{t}$ is the Regulation Down Neutrality Adjustment Rate for Settlement Period *t*. The rate is the difference between the total amount of charge and the total amount of payment for the service divided by the total Demand of the ISO control area as follows.

$$AGCDownNeutraAdjRate_{t} = \frac{AGCDownChgTotal_{t} - AGCDownPayTotal_{t}}{MeteredLoadTotal_{t}}$$

where:

$AGCDownChgTotal_{t}$ is the total amount of charges collected by the ISO from Scheduling Coordinators for provision of Regulation Down Service for the Settlement Period *t*.

$$AGCDownChgTotal_{t} = \sum_{j} AGCDownChg_{jt}$$

$AGCDownPayTotal_{t}$ is the total amount of payment from the ISO to Scheduling Coordinators for procuring Regulation Down Service for the Settlement Period *t* in both the Day-Ahead and the Hour-Ahead Markets.

$$AGCDownPayTotal_{t} = \sum_{j} \sum_{x} \left(AGCDownPayTotalDA_{jxt} + AGCDownPayTotalHA_{jxt} \right)$$

C.2.2.3. **Spinning Reserve**

The ISO will charge the cost of procuring Spinning Reserve in the Day-Ahead and Hour-Ahead Markets, through the application of a charge to each Scheduling Coordinator for each Settlement Period at the ISO Control Area level. This charge will be computed by multiplying the Spinning Reserve user rate for the Settlement Period by the Scheduling Coordinator's Net Spinning Reserve Obligation for the same period.

The Spinning Reserve user rate is calculated by dividing the total cost to the ISO for purchasing the Net Spinning Reserve Requirement, for the Settlement Period, by the Net Spinning Reserve Requirement for the Settlement Period.

The Spinning Reserve user rate for Settlement Period t is calculated as follows:

$$SpinRate_t = \frac{SpinPayNetReqDA_t + SpinPayNetReqHA_t}{SpinNetReqDA_t + SpinNetReqHA_t}$$

where:

SpinNetReqDA$_t$ is the Net Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market. It is the sum of all the Regional Net Spinning Reserve Requirement as follows:

$$SpinNetReqDA_t = \sum_y SpinNetReqDA_{yt}$$

SpinPayNetReqDA$_t$ is the cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period *t* incurred in the Day-Ahead Market. It is calculated as follows:

$$SpinPayNetReqDA_t = \sum_y SpinPayNetReqDA_{yt}$$

SpinPayNetReqDA$_{yt}$ is the cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market in Region *y*. It is calculated as follows:

$$SpinPayNetReqDA_{yt} = SpinNetReqDA_{yt} \times AvgPSpinDA_{yt}$$

where:

SpinNetReqDA$_{yt}$ is the Net Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market for Region *y*.

AvgPSpinDA$_{yt}$ is the average price for Spinning Reserve for the Settlement Period *t* in the Day-Ahead Market for Region *y*.

$$AvgPSpinDA_{yt} = \frac{\sum_{k \in I_y} SpinQDA_{kt} \times PSpinDA_{kt}}{\sum_{k \in I_y} SpinQDA_{kt}}$$

$SpinQDA_{kt}$ is the quantity of procurement for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point *k* which is connected directly to Region *y*.

$PSpinDA_{kt}$ is the Ancillary Service Marginal Price of Spin for the Settlement Period *t* in the Day-Ahead Market in Region *y* or at Scheduling Point k which is connected directly to Region *y*.

I_y is the set of Ancillary Service Regions that consist of Region y itself and the Scheduling Points that are connected directly to Region *y*.

$SpinNetReqHA_t$ is the Net Spinning Reserve Requirement for the Settlement Period *t* in the Hour-Ahead Market. It is the sum of all the Regional Net Spinning Reserve Requirement as follows:

$$SpinNetReqHA_t = \sum_z SpinNetReqHA_{zt}$$

$SpinPayNetReqHA_t$ is the cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market. It is calculated as follows:

$$SpinPayNetReqHA_t = \sum_z SpinPayNetReqHA_{zt}$$

$SpinPayNetReqHA_{zt}$ is the cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market in Region *z*. It is calculated as follows:

$$SpinPayNet\,\mathrm{Re}\,qDA_{zt} = SpinNet\,\mathrm{Re}\,qHA_{yt} \times AvgPSpinHA_{kt}$$

where:

$SpinNetReqHA_{zt}$ is the Net Spinning Reserve Requirement for the Settlement Period *t* in the Hour-Ahead Market for Region *z*.

$AvgPSpinHA_{zt}$ is the average price for Spinning Reserve for the Settlement Period *t* in the Hour-Ahead Market for Region *z*.

$$AvgPSpinHA_{zt} = \frac{\sum_{k \in I_z} \left(SpinQIHA_{kt} \times PSpinHA_{kt} - SpinReceiveHA_{kt}\right)}{\sum_{k \in I_z} \left(SpinQIHA_{kt} - SpinQDHA_{kt}\right)}$$

$SpinQIHA_{kt}$ is the quantity of Incremental Procurement for the Settlement Period t in the Hour-Ahead Market in Region *z* or at Scheduling Point k which is connected directly to Region *z*.

$PSpinHA_{kt}$ is the Ancillary Service Marginal Price of Spin for the Settlement Period t in the Hour-Ahead Market in Region *z* or at Scheduling Point *k* which is connected directly to Region *z*.

$SpinReceiveHA_{kt}$ is the total charges for Hour-Ahead Buyback of Spinning Reserve for the Settlement Period *t* for Region *z* or Scheduling Point k which is connected directly to Region *z*.

I_z is the set of Ancillary Service Regions that consist of Region *z* itself and the Scheduling Points that are connected directly to Region *z*.

The Spinning Reserve capacity charge for Scheduling Coordinator j for Settlement Period *t* is calculated as follows:

$$SpinChg_{jt} = SpinNetOblig_{jt} \times SpinRate_t$$

$SpinNetOblig_{jt}$ is the Net Spinning Reserve Obligation for Scheduling Coordinator *j* for Settlement Period *t*. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Spinning Reserve.

$$SpinNetOblig_{jt} = SpinGrossOblig_{jt} - SpinQualifySelf_{jt}$$

where:

$SpinGrossOblig_{jt}$ is the gross Spinning Reserve Obligation for Scheduling Coordinator *j* for Settlement Period *t*.

$SpinQualifySelf_{jt}$ is the Qualified Self-Provision of Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$SpinQualifySelf_{jt} = SpinQualifySelfDA_{jt} + SpinQualifySelfHA_{jt}$$

$SpinQualifySelfDA_{jt}$ is the Qualified Day-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$SpinQualifySelfDA_{jt} = \sum_{y} SpinQualifySelfDA_{jyt}$$

$SpinQualifySelfHA_{jt}$ is the Qualified Hour-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$SpinQualifySelfHA_{jt} = \sum_{z} SpinQualifySelfHA_{jzt}$$

where:

$SpinQualifySelfDA_{jyt}$ is the Qualified Day-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator *j* in Region *y* for Settlement Period *t*.

$SpinQualifySelfHA_{jzt}$ is the Qualified Hour-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator *j* in Region *z* for Settlement Period *t*.

The ISO will charge each Scheduling Coordinator a Spinning Reserve Neutrality Adjustment Charge for each Settlement Period according to Metered Demand.

$$SpinNeutraAdjChg_{jt} = MeteredDemand_{jt} \times SpinNeutraAdjRate_t$$

where:

$SpinNeutraAdjChg_{jt}$ is the Spinning Reserve Neutrality Adjustment Charge to Scheduling Coordinator j for Settlement Period *t*.

$MeteredDemand_{jt}$ is the metered demand of Scheduling Coordinator *j* for Settlement Period *t*.

$SpinNeutraAdjRate_t$ is the Spinning Reserve Neutrality Adjustment Rate for Settlement Period *t*. The rate is the difference between the total amount of charge and the total amount of payment adjusted by the total congestion charge for the service divided by the total Metered Demand of the control area as follows.

$$SpinNeutraAdjRate_t = \frac{SpinChgTotal_t - SpinPayTotal_t - SpinCCTotal_t}{MeteredDemandTotal_t}$$

where:

$SpinChgTotal_t$ is the total amount of charges collected by the ISO from Scheduling Coordinators for provision of Spinning Reserve Service for the Settlement Period *t*.

$$SpinChgTotal_t = \sum_j SpinChg_{jt}$$

$SpinPayTotal_t$ is the total amount of payment from the ISO to Scheduling Coordinators for procuring Spinning Reserve Service for the Settlement Period *t* in both the Day-Ahead and the Hour-Ahead Markets.

$$SpinPayTotal_t = \sum_j \sum_x \left(SpinPayTotalDA_{jxt} + SpinPayTotalHA_{jxt}\right)$$

$SpinCCTotal_t$ is the total amount of Congestion Charge incurred to the ISO for procuring Spinning Reserve over Congested interties for the Settlement Period t. This amount should be transferred into the FTR Balancing Account to balance the Congestion Charge receivables booked in the Day-Ahead Market and the Hour-Ahead Market when the Spinning Reserves are procured.

$$SpinCCTotal_t = \sum_j \sum_x \sum_i SpinCCDA_{ijxt} + \sum_j \sum_x \sum_i \left(SpinCCHA_{ijxt} - SpinCPHA_{ijxt}\right)$$

C.2.2.4. Non-Spinning Reserve

The ISO will charge the cost of procuring Non-Spinning Reserve in the Day-Ahead and Hour-Ahead Markets, through the application of a charge to each Scheduling Coordinator for each Settlement Period at the ISO Control Area level. This charge will be computed by multiplying the Non-Spinning Reserve user rate for the Settlement Period by the Scheduling Coordinator's Net Non-Spinning Reserve Obligation for the same period.

The Non-Spinning Reserve user rate is calculated by dividing the total cost to the ISO for purchasing the Net Non-Spinning Reserve Requirement, for the Settlement Period, by the Net Non-Spinning Reserve Requirement for the Settlement Period.

The Non-Spinning Reserve user rate for Settlement Period *t* is calculated as follows:

$$NonSpinRate_t = \frac{NonSpinPayNetReqDA_t + NonSpinPayNetReqHA_t}{NonSpinNetReqDA_t + NonSpinNetReqHA_t}$$

where:

$NonSpinNetReqDA_t$ is the Net Non-Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market. It is the sum of all the Regional Net Non-Spinning Reserve Requirement as follows:

$$NonSpinNetReqDA_t = \sum_y NonSpinNetReqDA_{yt}$$

$NonSpinPayNetReqDA_t$ is the cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period *t* incurred in the Day-Ahead Market. It is calculated as follows:

$$NonSpinPayNetReqDA_t = \sum_y NonSpinPayNetReqDA_{yt}$$

$NonSpinPayNetReqDA_{yt}$ is the cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market in Region *y*. It is calculated as follows:

$$NonSpinPayNet\,\mathrm{Re}\,qDA_{yt} = NonSpinNet\,\mathrm{Re}\,qDA_{yt} \times AvgPNonSpinDA_{yt}$$

where:

$NonSpinNetReqDA_{yt}$ is the Net Non-Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market for Region *y*.

$AvgPNonSpinDA_{yt}$ is the average price for Non-Spinning Reserve for the Settlement Period *t* in the Day-Ahead Market for Region *y*.

$$AvgPNonSpinDA_{yt} = \frac{\sum_{k \in I_y} NonSpinQDA_{kt} \times PNonSpinDA_{kt}}{\sum_{k \in I_y} NonSpinQDA_{kt}}$$

$NonSpinQDA_{kt}$ is the quantity of procurement for the Settlement Period t in the Day-Ahead Market in Region *y* or at Scheduling Point *k* which is connected directly to Region *y*.

$PNonSpinDA_{kt}$ is the Ancillary Service Marginal Price of Non-Spinning Reserve for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point *k* which is connected directly to Region *y*.

I_y = The set of Ancillary Service Regions that consist of Region y itself and the Scheduling Points that are connected directly to Region *y*.

$NonSpinNetReqHA_t$ is the Net Non-Spinning Reserve Requirement for the Settlement Period *t* in the Hour-Ahead Market. It is the sum of all the Regional Net Non-Spinning Reserve Requirement as follows:

$$NonSpinNetReqHA_t = \sum_z NonSpinNetReqHA_{zt}$$

$NonSpinPayNetReqHA_t$ is the cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market. It is calculated as follows:

$$NonSpinPayNetReqHA_t = \sum_z NonSpinPayNetReqHA_{zt}$$

$NonSpinPayNetReqHA_{zt}$ is the cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market in Region *z*. It is calculated as follows:

$$NonSpinPayNet\mathrm{Re}\,qDA_{zt} = NonSpinNet\mathrm{Re}\,qHA_{zt} \times AvgPNonSpinHA_{zt}$$

where:

$NonSpinNetReqHA_{zt}$ is the Net Non-Spinning Reserve Requirement for the Settlement Period *t* in the Hour-Ahead Market for Region *z*.

$AvgPNonSpinHA_{zt}$ is the average Pprice for Non-Spinning Reserve for the Settlement Period *t* in the Hour-Ahead Market for Region *z*.

$$AvgPNonSpinHA_{zt} = \frac{\sum_{k \in I_z} \left(NonSpinQIHA_{kt} \times PNonSpinHA_{kt} - NonSpin\mathrm{Re}\,ceiveHA_{kt}\right)}{\sum_{k \in I_z} \left(NonSpinQIHA_{kt} - NonSpinQDHA_{kt}\right)}$$

$NonSpinQIHA_{kt}$ is the quantity of incremental procurement for the Settlement Period *t* in the Hour-Ahead Market in Region *z* or at Scheduling Point *k* which is connected directly to Region *z*.

$PNonSpinHA_{kt}$ is the Ancillary Service Marginal Price of Non-Spinning Reserve for the Settlement Period *t* in the Hour-Ahead Market in Region *z* or at Scheduling Point *k* which is connected directly to Region *z*.

$NonSpinReceiveHA_{kt}$ is the total charges for Hour-Ahead Buyback of Non-Spinning Reserve for the Settlement Period *t* for Region *z* or Scheduling Point *k* which is connected directly to Region *z*.

I_z is the set of Ancillary Service Regions that consist of Region *z* itself and the Scheduling Points that are connected directly to Region *z*.

The Non-Spinning Reserve capacity charge for Scheduling Coordinator *j* for Settlement Period *t* is calculated as follows:

$$NonSpinChg_{jt} = NonSpinNetOblig_{jt} \times NonSpinRate_t$$

NonSpinNetOblig$_{jt}$ is the Net Non-Spinning Reserve Obligation for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t*. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Non-Spinning Reserve.

$$NonSpinNetOblig_{jt} = NonSpinGrossOblig_{jt} - NonSpinQualifySelf_{jt}$$

where:

NonSpinGrossOblig$_{jt}$ is the gross Non-Spinning Reserve Obligation for Scheduling Coordinator *j* for Settlement Period *t*.

NonSpinQualifySelf$_{jt}$ is the Qualified Self-Provision of Non-Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$NonSpinQualifySelf_{jt} = NonSpinQualifySelfDA_{jt} + NonSpinQualifySelfHA_{jt}$$

NonSpinQualifySelfDA$_{jt}$ is the Qualified Day-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$NonSpinQualifySelfDA_{jxt} = NonSpinQualifySelfDA_{jyt} \times \frac{NonSpinGrossOblig_{jxt}}{NonSpinGrossOblig_{jyt}}$$

NonSpinQualifySelfHA$_{jt}$ is the Qualified Hour-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$NonSpinQualifySelfHA_{jt} = \sum_{z} NonSpinQualifySelfHA_{jzt}$$

where:

NonSpinQualifySelfDA$_{jyt}$ = The Qualified Day-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator j in Region y for Settlement Period t.

NonSpinQualifySelfHA$_{jzt}$ = The Qualified Hour-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator j in Region z for Settlement Period t.

The ISO will charge each Scheduling Coordinator a Non-Spinning Reserve Neutrality Adjustment Charge for each Settlement Period according to Metered Demand.

$$NonSpinNeutraAdjChg_{jt} = MeteredDemand_{jt} * NonSpinNeutraAdjRate_t$$

where

NonSpinNeutraAdjChg$_{jt}$ = Non-Spinning Reserve Neutrality Adjustment Charge to Scheduling Coordinator j for Settlement Period t.

$MeteredDemand_{jt}$ = the metered demand of Scheduling Coordinator j for Settlement Period t.

$NonSpinNeutraAdjRate_t$ = the Non-Spinning Reserve Neutrality Adjustment Rate for Settlement Period t. The rate is the difference between the total amount of charge and the total amount of payment adjusted by the total congestion charge for the service divided by the total Metered Demand of the control area as follows.

$$NonSpinNeutraAdjRate_t = \frac{NonSpinChgTotal_t - NonSpinPayTotal_t - NonSpinCCTotal_t}{MeteredDemandTotal_t}$$

where

$NonSpinChgTotal_t$ = Total amount of charges collected by the ISO from Scheduling Coordinators for provision of Non-Spinning Reserve Service for the Settlement Period t.

$$NonSpinChgTotal_t = \sum_j NonSpinChg_{jt}$$

$NonSpinPayTotal_t$ = Total amount of payment from the ISO to Scheduling Coordinators for procuring Non-Spinning Reserve Service for the Settlement Period t in both the Day-Ahead and the Hour-Ahead Markets.

$$NonSpinPayTotal_t = \sum_j \sum_x \left(NonSpinPayTotalDA_{jxt} + NonSpinPayTotalHA_{jxt}\right)$$

$NonSpinCCTotal_t$ is the total amount of Congestion Charge incurred to the ISO for procuring Non-Spinning Reserve over Congested interties for the Settlement Period *t*. This amount should be transferred into the FTR Balancing Account to balance the Congestion Charge receivables booked in the Day-Ahead Market and the Hour-Ahead Market when the Non-Spinning Reserves are procured.

$$NonSpinCCTotal_t = \sum_j \sum_x \sum_i NonSpinCCDA_{ijxt} + \sum_j \sum_x \sum_i \left(NonSpinCCHA_{ijxt} - NonSpinCPHA_{ijxt}\right)$$

C.2.3. **C 2.3 Default User Rate**

If, in any Settlement Period, no quantity of Regulation, Spinning Reserve, or Non-Spinning Reserve is purchased in the Day-Ahead or Hour-Ahead Markets due to excess self-provision in all Ancillary Service Regions, then in lieu of the user rate determined in accordance with this Appendix C the user rate for the affected Ancillary Service for that Settlement Period in the region shall be determined to be zero.

C.3. **Meaning of Terms in Formulae**

C.3.1. **$AGCUpPayDA_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing Regulation Up capacity in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.2. **$AGCDownPayDA_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing Regulation Down capacity in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.3. **$AGCUpQDA_{ijxt}$ – MW**

The total quantity of Regulation Up capacity provided in the ISO Day-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.4. **$AGCDownQDA_{ijxt}$ – MW**

The total quantity of Regulation Down capacity provided in the ISO Day-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.5. **$PAGCUpDA_{xt}$ - $/MW**

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those Units subject to the cap for Regulation Up Capacity in the Day-Ahead Market for Settlement Period t in Ancillary Service Region x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Regulation Up Capacity in Ancillary Service Region x for Settlement Period t.

C.3.6. **$PAGCDownDA_{xt}$ - $/MW**

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those Units subject to the cap for Regulation Down Capacity in the Day-Ahead Market for Settlement Period t in Ancillary Service Region x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Regulation Down Capacity in Ancillary Service Region x for Settlement Period t.

C.3.7. **$AGCUpPayTotalDA_{jxt}$ - $**

The total payment for Regulation Up capacity to Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

$AGCDownPayTotalDA_{jxt}$ - $

The total payment for Regulation Down capacity to Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.8. **$AGCUpPayHA_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Regulation Up capacity in the Hour-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

$AGCDownPayHA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Regulation Down capacity in the Hour-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.9. **$AGCUpReceiveHA_{ijxt}$ - $**

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead Regulation Up capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.10. **$AGCDownReceiveHA_{ijxt}$ - $**

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead Regulation Down capacity which the ISO hadpurchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.11. **$AGCUpQIHA_{ijxt}$ – MW**

The total quantity of incremental (additional to Day-Ahead) Regulation Up capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.12. **$AGCDownQIHA_{ijxt}$ – MW**

The total quantity of incremental (additional to Day-Ahead) Regulation Down capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.13. **$AGCUpQDHA_{ijxt}$ – MW**

The total quantity of decremental (less than Day-Ahead) Regulation Up capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.14. **$AGCDownQDHA_{ijxt}$ – MW**

The total quantity of decremental (less than Day-Ahead) Regulation Down capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.15. **$PAGCUpHA_{xt}$ - $/MW**

The Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Regulation Up capacity in the Hour-Ahead Market for Settlement Period t in Ancillary Service Region x. On buyback condition, MCP applies.

C.3.16. **$PAGCDownHA_{xt}$ - $/MW**

The Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Regulation Down capacity in the Hour-Ahead Market for Settlement Period t in Ancillary Service Region x. On buyback condition, MCP applies.

C.3.17. **$AGCUpPayTotalHA_{jxt}$ - $**

The total payment for incremental (additional to Day-Ahead) Regulation Up capacity to Scheduling Coordinator j in the Hour-Ahead Market in Ancillary Service Region x for Settlement Period t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Regulation Up capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.18. **$AGCDownPayTotalHA_{jxt}$ - $**

The total payment for incremental (additional to Day-Ahead) Regulation Down capacity to Scheduling Coordinator j in the Hour-Ahead Market in Ancillary Service Region x for Settlement Period t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Regulation Down capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.19. **$SpinPayDA_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing Spinning Reserve capacity in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.20. **$SpinQDA_{ijxt}$ – MW**

The total quantity of Spinning Reserve capacity provided in the Day-Ahead Market by resource i represented by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.21. **$PSpinDA_{xt}$ -$/MW**

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Day-Ahead Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for Spinning Reserve Capacity in Ancillary Service Region x for Settlement Period t. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Spinning Reserve Capacity in Ancillary Service Region x for Settlement Period t.

C.3.22. **$SpinPayTotalDA_{jxt}$ - $**

The total payment to Scheduling Coordinator j for Spinning Reserve capacity in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.23. **$SpinPayHA_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.24. **$SpinReceiveHA_{Iijxt}$ - $**

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.25. **$SpinQIHA_{ijxt}$ – MW**

The total quantity of incremental (additional to Day-Ahead) Spinning Reserve capacity provided in the Hour-Ahead Market by resource i represented by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.26. **$SpinQDHA_{ijxt}$ – MW**

The total quantity of decremental (less than Day-Ahead) Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.27. **$PSpinHA_{xt}$ -$/MW**

The Hour-Ahead Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Spinning Reserve capacity in Ancillary Service Region x for Settlement Period t. On Buyback condition, MCP applies charge for HA.

C.3.28. **$SpinPayTotalHA_{jxt}$ - $**

The total payment to Scheduling Coordinator j for incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market in Ancillary Service Region x for Settlement Period t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.29. **$NonSpinPayDA_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.30. **$NonSpinQDA_{ijxt}$ – MW**

The total quantity of Non-Spinning Reserve capacity provided from resource i in the Day-Ahead Market by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.31. **$PNonSpinDA_{xt}$ - $/MW**

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Day-Ahead Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for Non-Spinning Reserve Capacity for Settlement Period t in Ancillary Service Region x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Non-Spinning Reserve Capacity in Ancillary Service Region x for Settlement Period t.

C.3.32. **NonSpinPayTotalDA$_{jxt}$ - $**

The total payment to Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.33. **NonSpinPayHA$_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.34. **NonSpinReceiveHA$_{ijxt}$ - $**

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.35. **NonSpinQIHA$_{ijxt}$ – MW**

The total quantity of incremental (additional to Day-Ahead) Non-Spinning Reserve capacity provided from resource i in the Hour-Ahead Market by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.36. **NonSpinQDHA$_{ijxt}$ – MW**

The total quantity of decremental (less than Day-Ahead) Non-Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.37. **PNonSpinHA$_{xt}$ - $/MW**

The Hour-Ahead zonal Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Non-Spinning Reserve capacity for Settlement Period t in Ancillary Service Region x. On Buyback condition, MCP applies.

C.3.38. **NonSpinPayTotalHA$_{jxt}$ - $**

The total payment to Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market in Ancillary Service Region x for Settlement Period t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.39. **$PCCDA_{xt}$ - $/MW**

Price of Congestion Charge in the Day-Ahead Market at Scheduling Point x for Settlement Period t.

C.3.40. **$PCCHA_{xt}$ - $/MW**

Price of Congestion Charge in the Hour-Ahead Market at Scheduling Point x for Settlement Period t.

C.3.41. **AGCUpRatet - $/MW**

The Regulation Up user rate for Settlement Period t.

C.3.42. **$AGCUpNetReqDA_{t}$ – MW**

Net Regulation Up Requirement for the Settlement Period t in the Day-Ahead Market. It is the sum of all the Regional Net Regulation Up Requirement.

C.3.43. **$AGCUpPayNetReqDA_{t}$ - $**

Cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Day-Ahead Market.

C.3.44. **$AGCUpPayNetReqDA_{yt}$ - $**

Cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Day-Ahead Market in Region y.

C.3.45. **$AGCUpNetReqDA_{yt}$ – MW**

Net Regulation Up Requirement for the Settlement Period t in the Day-Ahead Market for Region y .

C.3.46. **$PAGCUpDA_{yt}$ - $/MW**

Ancillary Service Marginal Price for Regulation Up for the Settlement Period t incurred in the Day-Ahead Market for Region y.

C.3.47. **$AGCUpNetReqHA_{t}$ – MW**

Net Regulation Up Requirement for the Settlement Period t in the Hour-Ahead Market. It is the sum of all the Regional Net Regulation Up Requirement

C.3.48. **$AGCUpPayNetReqHA_{t}$ - MW**

Cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Hour-Ahead Market.

C.3.49. $AGCUpPayNetReqHA_{zt}$ - $

Cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Hour-Ahead Market in Region z.

C.3.50. $AGCUpNetReqHA_{yt}$ – MW

Total incremental Net Requirement of Regulation Up for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.51. $PAGCUpHA_{yt}$ - $/MW

Ancillary Service Marginal Price for Regulation Up for the Settlement Period t incurred in the Hour-Ahead Market for Region z.

C.3.52. $AGCUpReceiveHA_{yt}$ - $

Total charges for Hour-Ahead Buyback of Regulation Up for the Settlement Period t for Region z.

C.3.53. $AGCUpNetOblig_{jt}$ – MW

The Net Regulation Up Obligation for Scheduling Coordinator j for Settlement Period t. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Regulation Up.

C.3.54. $AGCUpGrossOblig_{jt}$ – MW

The Gross Regulation Up Obligation for Scheduling Coordinator j for Settlement Period t.

C.3.55. $AGCUpQualifySelf_{jt}$ – MW

The Qualified Self-Provision of Regulation Up for Scheduling Coordinator j for Settlement Period t.

C.3.56. $AGCUpQualifySelfDA_{jt}$ – MW

The Qualified Day-Ahead Self-Provision of Regulation Up for Scheduling Coordinator j for Settlement Period t.

C.3.57. $AGCUpQualifySelfHA_{jt}$ – MW

The Qualified Hour-Ahead Self-Provision of Regulation Up for Scheduling Coordinator j for Settlement Period t.

C.3.58. $AGCUpQualifySelfDA_{jyt}$ – MW

The Qualified Day-Ahead Self-Provision of Regulation Up for Scheduling Coordinator j in Region y for Settlement Period t.

C.3.59. **$AGCUpQualifySelfHA_{jzt}$ – MW**

The Qualified Hour-Ahead Self-Provision of Regulation Up for Scheduling Coordinator j in Region z for Settlement Period t.

C.3.60. **$AGCUpGrossOblig_{jyt}$ – MW**

The Gross Regulation Up Obligation for Scheduling Coordinator j in Region y (defined in Day-Ahead) for Settlement Period t.

C.3.61. **$AGCUpGrossOblig_{jzt}$ – MW**

The Gross Regulation Up Obligation for Scheduling Coordinator j in Region z (defined in Hour-Ahead) for Settlement Period t.

C.3.62. **Regulation Up Neutrality Adjustment Rate – $/MW**

The ISO will charge each Scheduling Coordinator a Regulation Up Neutrality Adjustment Charge in proportion to Demand. The rate for this charge is the difference between the total amount that the ISO pays out and the total amount that the ISO collects divided by the total Demandof the ISO Control Area.

C.3.63. **$AGCDownRate_{t}$ - $/MW**

Regulation Down user rate for Settlement Period t is calculated.

C.3.64. **$AGCUpNetReqDA_{t}$ – MW**

Net Regulation Down Requirement for the Settlement Period t in the Day-Ahead Market. It is the sum of all the Regional Net Regulation Down Requirement.

C.3.65. **$AGCDownPayNetReqDA_{t}$ - $**

Cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period t incurred in the Day-Ahead Market.

C.3.66. **$AGCDownPayNetReqDA_{yt}$ - $**

Cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period t incurred in the Day-Ahead Market in Region y.

C.3.67. **$AGCDownNetReqDA_{yt}$ – MW**

Net Regulation Down Requirement for the Settlement Period t in the Day-Ahead Market for Region y.

C.3.68. **$PAGCDownDA_{yt}$ - $/MW**

Ancillary Service Marginal Price for Regulation Down for the Settlement Period t incurred in the Day-Ahead Market for Region y.

C.3.69. **AGCDownNetReqHA$_t$ – MW**

Net Regulation Down Requirement for the Settlement Period t in the Hour-Ahead Market. It is the sum of all the Regional Net Regulation Down Requirement.

C.3.70. **AGCDownPayNetReqHA$_t$ - $**

Cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period t incurred in the Hour-Ahead Market.

C.3.71. **AGCDownPayNetReqHA$_{zt}$ - $**

Cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period t incurred in the Hour-Ahead Market in Region z.

C.3.72. **AGCDownNetReqHA$_{zt}$ – MW**

Total incremental Net Requirement of Regulation Down for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.73. **PAGCDownHA$_{zt}$ - $/MW**

Ancillary Service Marginal Price for Regulation Down for the Settlement Period t incurred in the Hour-Ahead Market for Region z.

C.3.74. **AGCDownReceiveHA$_{zt}$ - $**

Total charges for Hour-Ahead buy-back of Regulation Down for the Settlement Period t for Region z.

C.3.75. **AGCDownNetOblig$_{jt}$ – MW**

The Net Regulation Down Obligation for Scheduling Coordinator j for Settlement Period t. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Regulation Down.

C.3.76. **AGCDownGrossOblig$_{jt}$ – MW**

The Gross Regulation Down Obligation for Scheduling Coordinator j for Settlement Period t.

C.3.77. **AGCDownQualifySelf$_{jt}$ – MW**

The Qualified Self-Provision of Regulation Down for Scheduling Coordinator j for Settlement Period t.

C.3.78. **AGCDownQualifySelfDA$_{jt}$ – MW**

The Qualified Day-Ahead Self-Provision of Regulation Down for Scheduling Coordinator j for Settlement Period t.

C.3.79. **$AGCDownQualifySelfHA_{jt}$ – MW**

The Qualified Hour-Ahead Self-Provision of Regulation Down for Scheduling Coordinator j for Settlement Period t.

C.3.80. **$AGCDownQualifySelfDA_{jyt}$ – MW**

The Qualified Day-Ahead Self-Provision of Regulation Down for Scheduling Coordinator j in Region y for Settlement Period t.

C.3.81. **$AGCDownQualifySelfHA_{jzt}$ – MW**

The Qualified Hour-Ahead Self-Provision of Regulation Down for Scheduling Coordinator j in Region z for Settlement Period t.

C.3.82. **$AGCDownGrossOblig_{jyt}$ – MW**

The Gross Regulation Down Obligation for Scheduling Coordinator j in Region y (defined in Day-Ahead) for Settlement Period t.

C.3.83. **$AGCDownGrossOblig_{jzt}$ – MW**

The Gross Regulation Down Obligation for Scheduling Coordinator j in Region z (defined in Hour-Ahead) for Settlement Period t.

C.3.84. **AGCDownNeutraAdjRate - $/MW**

The ISO will charge each Scheduling Coordinator a Regulation Down Neutrality Adjustment Charge in proportion to Demand. The rate for this charge is the difference between the total amount that the ISO pays out and the total amount that the ISO collects divided by the total Demand of the ISO Control Area.

C.3.85. **$SpinRate_t$ - $/MW**

The Spinning Reserve user rate for Settlement Period t.

C.3.86. **$SpinNetReqDA_t$ – MW**

Net Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market. It is the sum of all the Regional Net Spinning Reserve Requirement.

C.3.87. **$SpinPayNetReqDA_t$ - $**

Cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period t incurred in the Day-Ahead Market.

C.3.88. **$SpinPayNetReqDA_{yt}$ - $**

Cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market in Region y.

C.3.89. **$SpinNetReqDA_{yt}$ – MW**

Net Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market for Region y.

C.3.90. **$AvgPSpinDA_{yt}$ - $/MW**

Average Price for Spinning Reserve for the Settlement Period t in the Day-Ahead Market for Region y.

C.3.91. **$SpinQDA_{kt}$ – MW**

Quantity of procurement for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point k which is connected directly to Region y.

C.3.92. **$PSpinDA_{kt}$ - $/MW**

Ancillary Service Marginal Price of Spin for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point k which is connected directly to Region y.

C.3.93. **$PCCDA_{kt}$ – $/MW**

Price of Congestion Charge for the Settlement Period t in the Day-Ahead Market at Scheduling Point k which is connected directly to Region y.

C.3.94. **$SpinNetReqHA_{t}$ – MW**

Net Spinning Reserve Requirement for the Settlement Period t in the Hour-Ahead Market. It is the sum of all the Regional Net Spinning Reserve Requirement.

C.3.95. **$SpinPayNetReqHA_{t}$ - $**

Cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period t incurred in the Hour-Ahead Market.

C.3.96. **$SpinPayNetReqHA_{zt}$ - $**

Cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period t incurred in the Hour-Ahead Market in Region z.

C.3.97. **$SpinNetReqHA_{zt}$ – MW**

Net Spinning Reserve Requirement for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.98. **$AvgPSpinHA_{zt}$ - $/MW**

Average Price for Spinning Reserve for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.99. **$SpinQIHA_{kt}$ – MW**

Quantity of Incremental Procurement for the Settlement Period t in the Hour-Ahead Market in Region z or at Scheduling Point k which is connected directly to Region z.

C.3.100. **$PSpinHA_{kt}$ - $/MW**

Ancillary Service Marginal Price of Spinning Reserve for the Settlement Period t in the Hour-Ahead Market in Region z or at Scheduling Point k which is connected directly to Region z.

C.3.101. **$PCCHA_{kt}$ – $/MW**

Price of Congestion Charge for the Settlement Period t in the Hour-Ahead Market at Scheduling Point k which is connected directly to Region z.

C.3.102. **$SpinReceiveHA_{kt}$ - $**

Total charges for Hour-Ahead buyback of Spinning Reserve for the Settlement Period t for Region z or Scheduling Point k which is connected directly to Region z.

C.3.103. **$SpinNetOblig_{jt}$ – MW**

The Net Spinning Reserve Obligation for Scheduling Coordinator j for Settlement Period t. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Spinning Reserve .

C.3.104. **$SpinGrossOblig_{jt}$ – MW**

The Gross Spinning Reserve Obligation for Scheduling Coordinator j for Settlement Period t.

C.3.105. **$SpinQualifySelf_{jt}$ – MW**

The Qualified Self-Provision of Spinning Reserve for Scheduling Coordinator j for Settlement Period t.

C.3.106. **$SpinQualifySelfDA_{jt}$ – MW**

The Qualified Day-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator j for Settlement Period t.

C.3.107. **$SpinQualifySelfHA_{jt}$ – MW**

The Qualified Hour-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator j for Settlement Period t.

C.3.108. **$SpinQualifySelfDA_{jyt}$ – MW**

The Qualified Day-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator j in Region y for Settlement Period t.

C.3.109. $\text{SpinQualifySelfHA}_{jzt}$ – MW

The Qualified Hour-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator j in Region z for Settlement Period t.

C.3.110. $\text{SpinGrossOblig}_{jyt}$ – MW

The Gross Spinning Reserve Obligation for Scheduling Coordinator j in Region y (defined in Day-Ahead) for Settlement Period t.

C.3.111. $\text{SpinGrossOblig}_{jzt}$ – MW

The Gross Spinning Reserve Obligation for Scheduling Coordinator j in Region z (defined in Hour-Ahead) for Settlement Period t.

C.3.112. SpinNeutraAdjRate - $/MW

The ISO will charge each Scheduling Coordinator a Spinning Reserve Neutrality Adjustment Charge according to Metered Demand. The rate for this charge is the difference between the total amount that the ISO pays out and the total amount that the ISO collects divided by the total Metered Demand of the control area.

C.3.113. NonSpinRate – $/MW

The Non-Spinning Reserve user rate for Settlement Period t.

C.3.114. $\text{NonSpinNetReqDA}_{t}$ – MW

Net Non-Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market. It is the sum of all the Regional Net Non-Spinning Reserve Requirement.

C.3.115. $\text{NonSpinPayNetReqDA}_{t}$ - $

Cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period t incurred in the Day-Ahead Market.

C.3.116. $\text{NonSpinPayNetReqDA}_{yt}$ - $

Cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market in Region y.

C.3.117. $\text{NonSpinNetReqDA}_{yt}$ – MW

Net Non-Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market for Region y.

C.3.118. $\text{AvgPNonSpinDA}_{yt}$ - $/MW

Average Price for Non-Spinning Reserve for the Settlement Period t in the Day-Ahead Market for Region y.

C.3.119. **$NonSpinQDA_{kt}$ – MW**

Quantity of procurement for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point k which is connected directly to Region y.

C.3.120. **$PNonSpinDA_{kt}$ - $/MW**

Ancillary Service Marginal Price of Non-Spinning Reserve for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point k which is connected directly to Region y.

C.3.121. **$NonSpinNetReqHA_{t}$ – MW**

Net Non-Spinning Reserve Requirement for the Settlement Period t in the Hour-Ahead Market. It is the sum of all the Regional Net Non-Spinning Reserve Requirement.

C.3.122. **$NonSpinPayNetReqHA_{t}$ - $**

Cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period t incurred in the Hour-Ahead Market.

C.3.123. **$NonSpinPayNetReqHA_{zt}$ - $**

Cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period t incurred in the Hour-Ahead Market in Region z.

C.3.124. **$NonSpinNetReqHA_{zt}$ – MW**

Net Non-Spinning Reserve Requirement for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.125. **$AvgPNonSpinHA_{zt}$ - $/MW**

Average Price for Non-Spinning Reserve for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.126. **$NonSpinQIHA_{kt}$ – MW**

Quantity of Incremental Procurement for the Settlement Period t in the Hour-Ahead Market in Region z or at Scheduling Point k which is connected directly to Region z.

C.3.127. **$PNonSpinHA_{kt}$ – $/MW**

Ancillary Service Marginal Price of Non-Spinning Reserve for the Settlement Period t in the Hour-Ahead Market in Region z or at Scheduling Point k which is connected directly to Region z.

C.3.128. $NonSpinReceiveHA_{kt}$ - $

Total charges for Hour-Ahead Buyback of Non-Spinning Reserve for the Settlement Period t for Region z or Scheduling Point k which is connected directly to Region z.

C.3.129. $NonSpinNetOblig_{jt}$ – MW

The Net Non-Spinning Reserve Obligation for Scheduling Coordinator j for Settlement Period t. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Non-Spinning Reserve .

C.3.130. $NonSpinGrossOblig_{jt}$ – MW

The Gross Non-Spinning Reserve Obligation for Scheduling Coordinator j for Settlement Period t.

C.3.131. $NonSpinQualifySelf_{jt}$ – MW

The Qualified Self-Provision of Non-Spinning Reserve for Scheduling Coordinator j for Settlement Period t.

C.3.132. $NonSpinQualifySelfDA_{jt}$ – MW

The Qualified Day-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator j for Settlement Period t.

C.3.133. $NonSpinQualifySelfHA_{jt}$ – MW

The Qualified Hour-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator j for Settlement Period t.

C.3.134. $NonSpinQualifySelfDA_{jyt}$ – MW

The Qualified Day-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator j in Region y for Settlement Period t.

C.3.135. $NonSpinQualifySelfHA_{jzt}$ – MW

The Qualified Hour-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator j in Region z for Settlement Period t.

C.3.136. $NonSpinGrossOblig_{jyt}$ – MW

The Gross Non-Spinning Reserve Obligation for Scheduling Coordinator j in Region y (defined in Day-Ahead) for Settlement Period t.

C.3.137. $NonSpinGrossOblig_{jzt}$ – MW

The Gross Non-Spinning Reserve Obligation for Scheduling Coordinator j in Region z (defined in Hour-Ahead) for Settlement Period t.

C.3.138. **NonSpinNeutraAdjRate - $/MW**

The ISO will charge each Scheduling Coordinator a Non-Spinning Reserve Neutrality Adjustment Charge according to Metered Demand. The rate for this charge is the difference between the total amount that the ISO pays out and the total amount that the ISO collects divided by the total Metered Demand of the control area.

C.3.139. **$SpinCCDA_{ijxt}$ - $**

Congestion charge to Scheduling Coordinator j for providing Spinning Reserve capacity in the Day-Ahead Market from resource i at Scheduling Point x in Settlement Period t.

C.3.140. **$NonSpinCCDA_{ijxt}$ - $**

Congestion charge to Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market from resource i at Scheduling Point x in Settlement Period t.

C.3.141. **$SpinCCHA_{ijxt}$ - $**

Congestion charge to Scheduling Coordinator j for providing Spinning Reserve capacity in the Hour-Ahead Market from resource i at Scheduling Point x in Settlement Period t.

C.3.142. **$SpinCPHA_{ijxt}$ - $**

Congestion payment to Scheduling Coordinator j for providing Spinning Reserve capacity in the Hour-Ahead Market from resource i at Scheduling Point x in Settlement Period t.

C.3.143. **$NonSpinCCHA_{ijxt}$ - $**

Congestion charge to Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Hour-Ahead Market from resource i at Scheduling Point x in Settlement Period t.

C.3.144. **$NonSpinCPHA_{ijxt}$ - $**

Congestion payment to Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Hour-Ahead Market from resource i at Scheduling Point x in Settlement Period t.

C.3.145. **$AGCUpNeutraAdjChg_{jt}$ - $**

Regulation Up Neutrality Adjustment Charge to Scheduling Coordinator j for Settlement Period t.

C.3.146. **$MeteredLoad_{jt}$ - MW**

The Demand of Scheduling Coordinator j for Settlement Period t.

C.3.147. **$AGCUpNeutraAdjRate_t$ - $/MW**

The Regulation Up Neutrality Adjustment Rate for Settlement Period t. The rate is the difference between the total amount of charge and the total amount of payment for the service divided by the total Demand in the ISO Control Area.

C.3.148. **$AGCUpChgTotal_t$ - $**

Total amount of charges collected by the ISO from Scheduling Coordinators for provision of Regulation Up Service for the Settlement Period t.

C.3.149. **$AGCUpPayTotal_t$ - $**

Total amount of payment from the ISO to Scheduling Coordinators for procuring Regulation Up Service for the Settlement Period t in both the Day-Ahead and the Hour-Ahead Markets.

C.3.150. **$AGCUpCCDA_{ijxt}$ - $**

Congestion charge to Scheduling Coordinator j for providing Regulation Up in the Day-Ahead Market from resource i at Scheduling Point x in Settlement Period t.

C.3.151. **$AGCUpCCHA_{ijxt}$ - $**

Congestion charge to Scheduling Coordinator j for providing Regulation Up in the Hour-Ahead Market from resource i at Scheduling Point x in Settlement Period t.

C.3.152. **$AGCUpCPHA_{ijxt}$ - $**

Congestion payment to Scheduling Coordinator j for providing Regulation Up in the Hour-Ahead Market from resource i at Scheduling Point x in Settlement Period t.

C.3.153. **$AGCUpCCTotal_t$ - $**

Total amount of Congestion charge incurred to the ISO for procuring Regulation Up over Congested interties for the Settlement Period t. This amount should be transferred into the FTR Balancing Account to balance the Congestion charge receivables booked in the Day-Ahead Market and the Hour-Ahead Market when the Regulation Up Services are procured.

C.3.154. **$AGCDownNeutraAdjChg_{jt}$ - $**

Regulation Down Neutrality Adjustment Charge to Scheduling Coordinator j for Settlement Period t.

C.3.155. **AGCDownNeutraAdjRate$_t$ - $/MW**

The Regulation Down Neutrality Adjustment Rate for Settlement Period t. The rate is the difference between the total amount of charge and the total amount of payment for the service divided by the total Demand in the ISO Control Area.

C.3.156. **AGCDownChgTotal$_t$ - $**

Total amount of charges collected by the ISO from Scheduling Coordinators for provision of Regulation Down Service for the Settlement Period t.

C.3.157. **AGCDownPayTotal$_t$ - $**

Total amount of payment from the ISO to Scheduling Coordinators for procuring Regulation Down service for the Settlement Period t in both the Day-Ahead and the Hour-Ahead Markets.

C.3.158. **SpinNeutraAdjChg$_{jt}$ - $**

Spinning Reserve Neutrality Adjustment Charge to Scheduling Coordinator j for Settlement Period t.

C.3.159. **MeteredDemand$_{jt}$ – MW**

The Metered Demand of Scheduling Coordinator j for Settlement Period t.

C.3.160. **SpinNeutraAdjRate$_t$ - $/MW**

The Spinning Reserve Neutrality Adjustment Rate for Settlement Period t. The rate is the difference between the total amount of charge and the total amount of payment adjusted by the total congestion charge for the service divided by the total Metered Demand in the ISO Control Area.

C.3.161. **SpinChgTotal$_t$ - $**

Total amount of charges collected by the ISO from Scheduling Coordinators for provision of Spinning Reserve service for the Settlement Period t.

C.3.162. **SpinPayTotal$_t$ - $**

Total amount of payment from the ISO to Scheduling Coordinators for procuring Spinning Reserve service for the Settlement Period t in both the Day-Ahead and the Hour-Ahead Markets.

C.3.163. **SpinCCTotal$_t$ - $**

Total amount of Congestion charge incurred to the ISO for procuring Spinning Reserve over Congested interties for the Settlement Period t. This amount should be transferred into the FTR Balancing Account to balance the Congestion charge receivables booked in the Day-Ahead

Market and the Hour-Ahead Market when the Spinning Reserves are procured.

C.3.164. **$NonSpinNeutraAdjChg_{jt}$ - $**

Non-Spinning Reserve Neutrality Adjustment Charge to Scheduling Coordinator j for Settlement Period t.

C.3.165. **$NonSpinNeutraAdjRate_{t}$ - $/MW**

The Non-Spinning Reserve Neutrality Adjustment Rate for Settlement Period t. The rate is the difference between the total amount of charge and the total amount of payment adjusted by the total congestion charge for the service divided by the total Metered Demand of the ISO Control Area.

C.3.166. **$NonSpinChgTotal_{t}$ - $**

Total amount of charges collected by the ISO from Scheduling Coordinators for provision of Non-Spinning Reserve service for the Settlement Period t.

C.3.167. **$NonSpinPayTotal_{t}$ - $**

Total amount of payment from the ISO to Scheduling Coordinators for procuring Non-Spinning Reserve service for the Settlement Period t in both the Day-Ahead and the Hour-Ahead Markets.

C.3.168. **$NonSpinCCTotal_{t}$ - $**

Total amount of Congestion charge incurred to the ISO for procuring Non-Spinning Reserve over Congested interties for the Settlement Period t. This amount should be transferred into the FTR Balancing Account to balance the Congestion charge receivables booked in the Day-Ahead Market and the Hour-Ahead Market when the Non-Spinning Reserves are procured.

~~APPENDIX C~~

~~ANCILLARY SERVICES CHARGES COMPUTATION~~

~~C 1 Purpose of charges~~

~~The Ancillary Services Charges reimburse the ISO for the costs of purchasing Ancillary Services in the Day-Ahead and Hour-Ahead Markets. Each Scheduling Coordinator that does not self provide Ancillary Services must purchase these services from the ISO. The ISO will in turn purchase these Ancillary Services from Scheduling Coordinators in the markets. Ancillary Services purchased and resold by the ISO includes Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve. Any references in this Appendix C to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up" or "Regulation Down".~~

~~This Appendix C also addresses the payments by ISO to Scheduling Coordinators for the Dispatch of energy from Dispatched Ancillary Services Units and for the Dispatch of Supplemental Energy in the Real Time Market. The ISO recovers the costs of Real Time Dispatch of such energy through the Imbalance Energy charges described in Appendix D of this Protocol.~~

~~The reference to a Scheduling Coordinator by Zone refers to the Demand of that Scheduling Coordinator which is located in the Zone. A Generation Unit, Load, or System Resource located in another Control Area is considered to be located in the Zone in which its contract path enters the ISO Controlled Grid.~~

~~The ISO will purchase Ancillary Services for each Trading Interval in both the Day-Ahead and Hour-Ahead Markets. Separate payments will be calculated for each service for each Trading Interval and in each market for each Generating Unit, Load and System Resource. The ISO will then calculate a total payment for each Scheduling Coordinator for each Trading Interval for each service for each Zone in each market for all the Generating Units, Loads and System Resources that the Scheduling Coordinator represents. The ISO will charge Scheduling Coordinators for Ancillary Services, other than for energy, which they purchase from the ISO by calculating and applying charges to each Scheduling Coordinator for each Trading Interval for each service in each Zone in each market.~~

~~The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead Market and the Hour-Ahead Market, on a Zonal basis if the Day-Ahead Ancillary Services Market is procured on a Zonal basis. The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead Market and the Hour-Ahead Market, on an ISO Control Area wide basis if the Day-Ahead Ancillary Services Market is defined on an ISO Control Area wide basis.~~

~~C 2 Fundamental formulas~~

~~C 2.1 ISO payments to Scheduling Coordinators~~

~~C 2.1.1 Day-Ahead Market~~

~~C.3.168.1.1. (a) Regulation. When the ISO purchases Regulation capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over a given Trading Interval will be the total quantity of Regulation capacity provided times the zonal Market Clearing Price for that Trading Interval in that Zone. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. Regulation Up and Regulation Down payments shall be calculated separately. This payment for Scheduling Coordinator j for providing Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{AGCUpPayDA_{ijxt} = AGCUpQDA_{ijxt} * PAGCUpDA_{xt}}$$

~~C.3.168.1.2. This payment for Scheduling Coordinator j for providing Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{AGCDownPayDA_{ijxt} = AGCDownQDA_{ijxt} * PAGCDownDA_{xt}}$$

~~The total Regulation Up payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:~~

$$AGCUpPayTotalDA_{jxt} = \sum_{i} AGCUpPayDA_{ijxt}$$

~~The total Regulation Down payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:~~

$$AGCDownPayTotalDA_{jxt} = \sum_{i} AGCDownPayDA_{ijxt}$$

~~(b) Spinning Reserve. When ISO purchases Spinning Reserve capacity in the Day-Ahead Market. Scheduling Coordinators for Generating Units and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over a given Trading Interval will be the total quantity of Spinning Reserve capacity provided times the zonal Market Clearing Price for that Trading Interval in that Zone. The required Spinning Reserve capacity is defined in the Ancillary Services Requirements Protocol. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{SpinPayDA_{ijxt} = SpinQDA_{ijxt} * PSpinDA_{xt}}$$

~~The total Spinning Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{SpinPayTotalDA_{jxt} = \sum_{i} SpinPayDA_{ixt}}$$

~~C.3.168.1.3. (c) Non-Spinning Reserve. When the ISO purchases Non-Spinning Reserve capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over a given Trading Interval will be the total quantity of Non-Spinning Reserve capacity provided times the zonal Market Clearing Price for that Trading Interval in that Zone. The required Non-Spinning Reserve capacity is defined in the Ancillary Services Requirements Protocol. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{NonSpinPayDA_{ijxt} = NonSpinQDA_{ijxt} * PNonSpinDA_{xt}}$$

~~The total Non-Spinning Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{NonSpinPayTotalDA_{jxt} = \sum_{i} NonSpinPayDA_{ijxt}}$$

~~C.3.168.1.4. (d) Replacement Reserve. When the ISO purchases Replacement Reserve capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Replacement Reserve capacity over a given Trading Interval will be the total quantity of Replacement Reserve capacity provided times the zonal Market Clearing Price for thatTrading Interval in that Zone. The required Replacement Reserve capacity is defined in the Ancillary Services Requirements Protocol. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{ReplPayDA_{ijxt} = ReplQDA_{ijxt} * PReplDA_{xt}}$$

~~The total Replacement Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{ReplPayTotalDA_{jxt} = \sum_{i} ReplPayDA_{ijxt}}$$

~~C 2.1.2 Hour-Ahead Market~~

~~C.3.168.1.5. (a) Regulation. When the ISO purchases Regulation capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over the Trading Interval will be the total quantity of Regulation capacity provided times the zonal Market Clearing~~

~~C.3.168.1.6. Price for that Trading Interval in that Zone. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. Regulation Up and Regulation Down payments shall be calculated separately. This payment for Scheduling Coordinator j for providing Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{AGCUpPayHA_{ijxt} = AGCUpQIHA_{ijxt} * PAGCUpHA_{xt}}$$

~~C.3.168.1.7. This payment for Scheduling Coordinator j for providing Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{AGCDownPayHA_{ijxt} = AGCDownQIHA_{ijxt} * PAGCDownHA_{xt}}$$

~~When a Scheduling Coordinator buys back, in the Hour-Ahead Market, Regulation capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Regulation capacity bought back times the zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.~~

~~This payment to the ISO from Scheduling Coordinator j to buy back Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{AGCUpReceiveHA_{ijxt} = AGCUpQDHA_{ijxt} * PAGCUpHA_{xt}}$$

~~This payment to the ISO from Scheduling Coordinator j to buy back Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{AGCDownReceiveHA_{ijxt} = AGCDownQDHA_{ijxt} * PAGCDownHA_{xt}}$$

~~The total Regulation payment for the Trading Interval of the Hour-Ahead Market to each Scheduling Coordinator for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Regulation bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{AGCUpPayTotalHA_{jxt} = \sum_i AGCUpPayHA_{ijxt} - \sum_i AGCUpReceiveHA_{ijxt}}$$

$$AGCDownPayTotalHA_{jxt} = \sum_i AGCDownPayHA_{ijxt} - \sum_i AGCDownReceiveHA_{ijxt}$$

~~C.3.168.1.8. (b) Spinning Reserve. When the ISO purchases Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units and System Resources that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over the Trading Interval will be the total quantity of Spinning Reserve capacity provided times the zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

~~$SpinPayHA_{ijxt} = SpinQIHA_{ijxt} * PSpinHA_{xt}$~~

~~When a Scheduling Coordinator buys back in the Hour-Ahead Market Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Spinning Reserve capacity bought back times the zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.~~

~~This payment to the ISO from Scheduling Coordinator j to buy back Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

~~$SpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PSpinHA_{xt}$~~

~~The total Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{SpinPayTotalHA_{jxt} = \sum_i SpinPayHA_{ijxt} - \sum_i SpinReceiveHA_{ijxt}}$$

~~C.3.168.1.9. (c) Non-Spinning Reserve. When the ISO purchases Non-Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over the Trading Interval will be the total quantity of Non-Spinning~~

~~C.3.168.1.10. Reserve capacity provided times the zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

~~$NonSpinPayHA_{ijxt} = NonSpinQIHA_{ijxt} * PNonSpinHA_{xt}$~~

~~When a Scheduling Coordinator buys back in the Hour-Ahead Market Non-Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Non-Spinning Reserve capacity bought back times the zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.~~

~~This payment to the ISO from Scheduling Coordinator j to buy back Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

~~$NonSpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PNonSpinHA_{xt}$~~

~~The total Non-Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Non-Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:~~

$$NonSpinPayTotalHA_{jxt} = \sum_{i} NonSpinPayHA_{ijxt} - \sum_{i} NonSpinReceiveHA_{ijxt}$$

~~C.3.168.1.11. (d) Replacement Reserve. When the ISO purchases Replacement Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Replacement Reserve capacity over the Trading Interval will be the total quantity of Replacement Reserve capacity provided times the zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

~~$ReplPayHA_{ijxt} = ReplQIHA_{ijxt} * PReplHA_{xt}$~~

~~When a Scheduling Coordinator buys back in the Hour-Ahead Market Replacement Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Replacement Reserve capacity bought back times the zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.~~

~~This payment to the ISO from Scheduling Coordinator j to buy back Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{ReplReceiveHA_{ijxt} = ReplQDHA_{ijxt} * PReplHA_{xt}}$$

~~The total Replacement Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Replacement Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{ReplPayTotalHA_{jxt} = \sum_i ReplPayHA_{ijxt} - \sum_i ReplReceiveHA_{ijxt}}$$

~~C 2.2 ISO allocation of charges to Scheduling Coordinators~~

~~C 2.2.1 Day-Ahead Market~~

~~C.3.168.1.12. (a) Regulation. The ISO will charge the zonal cost of providing Regulation capacity that is not self provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Regulation user rate for the Trading Interval by the Scheduling Coordinator's Regulation obligation, for which it has not self provided, for the same period.~~

~~The zonal Regulation user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Regulation Capacity within the Zone, for the Trading Interval, by the total ISO Regulation MW purchases for the Trading Interval within the Zone. Regulation Up and Regulation Down payments shall be calculated separately.~~

~~The Day-Ahead Regulation Up user rate in Zone x for Trading Interval t is calculated as follows:~~

$$AGCUpRateDA_{xt} = \frac{\sum_j AGCUpPayTotalDA_{jxt}}{AGCUpPurchDA_{xt}}$$

~~where,~~

~~$AGCUpPayTotalDA_{ixt}$ = Total Regulation Up payments for the Settlement Period t in the Day-Ahead market for the Zone x.~~

~~The Day-Ahead Regulation Down user rate in Zone x for Trading Interval t is calculated as follows:~~

$$AGCDownRateDA_{xt} = \frac{\sum_j AGCDownPayTotalDA_{jxt}}{AGCDownPurchDA_{xt}}$$

~~where,~~

~~$AGCDownPayTotalDA_{jxt}$ = Total Regulation Down payments for the Settlement Period t in the Day-Ahead Market for the Zone x.~~

~~The Regulation capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{AGCUpChgDA_{jxt} = AGCUpOblig_{jxt} * AGCUpRateDA_{xt}}$$

$$\cancel{AGCDownChgDA_{jxt} = AGCDownOblig_{jxt} * AGCDownRateDA_{xt}}$$

~~C.3.168.1.13. (b) Spinning Reserve. The ISO will charge the zonal cost of providing Spinning Reserve capacity that is not self provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Spinning Reserve obligation, for which it has not self provided, for the same period. The zonal Spinning Reserve capacity user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Spinning Reserve capacity within the Zone, for the Trading Interval, by the total ISO Spinning Reserve MW purchases for the Trading Interval within the Zone. The Day-Ahead Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{SpinRateDA_{xt} = \frac{\sum_j SpinPayTotalDA_{jxt}}{SpinPurchDA_{xt}}}$$

~~The Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{SpinChgDA_{jxt} = SpinOblig_{jxt} * SpinRateDA_{xt}}$$

~~C.3.168.1.14. (c) Non-Spinning Reserve. The ISO will charge the zonal cost of providing Non-Spinning Reserve capacity that is not self provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Non-Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Non-Spinning Reserve obligation, for which it has not self provided, for the same period.~~

~~The zonal Non-Spinning Reserve capacity user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Non-Spinning Reserve capacity within the Zone, for the Trading Interval, by the total ISO Non-Spinning Reserve MW purchases for the Trading Interval within the Zone. The Day-Ahead Non-Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:~~

$$NonSpinRateDA_{xt} = \frac{\sum_j NonSpinPayTotalDA_{jxt}}{NonSpinPurchDA_{xt}}$$

~~The Non-Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:~~

$$NonSpinChgDA_{jxt} = NonSpinOblig_{jxt} * NonSpinRateDA_{xt}$$

~~C 2.2.2 Hour-Ahead Market~~

~~C.3.168.1.15. (a) Regulation. The ISO will charge the zonal net cost of providing Regulation capacity that is not self provided by Scheduling Coordinators, in the Hour-Ahead Market through the application of a charge to each Scheduling Coordinator for the Trading Interval concerned. This charge will be computed by multiplying the Regulation user rate for the Trading Interval by the Scheduling Coordinator's Regulation obligation, for which it has not self provided, for the same period.~~

~~The zonal Regulation capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to the ISO of purchasing Regulation capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Regulation bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone, for the Trading Interval, by the total ISO Regulation capacity MW purchases for the Trading Interval within the Zone. Regulation Up and Down payments shall be calculated separately. The Hour-Ahead Regulation Up capacity user rate in Zone x for Trading Interval t is calculated as follows:~~

$$AGCUpRateHA_{xt} = \frac{\sum_j AGCUpPayTotalHA_{jxt}}{AGCUpPurchHA_{xt}}$$

~~where,~~

~~$AGCUpPayTotalHa_{jxt}$= Totlal Regulation Up payments for the Settlement Period t in the Hour-Ahead Market for Zone x.~~

~~The Hour-Ahead Regulation Down capacity user rate in Zone x for Trading Interval t is calculated as follows:~~

$$AGCDownRateHA_{xt} \; \frac{\sum_j AGCDownPayTotalHA_{jxt}}{AGCDownPurchHA_{xt}}$$

~~where,~~

~~$AGCDownPayTotalHA_{xt}$ = Total Regulation Down payments for the Settlement Period t in the Hour-Ahead Market for Zone x.~~

~~The Regulation capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:~~

~~$AGCUpChgHA_{jxt} = (AGCUpOblig_{jxt} * AGCUpRateHA_{xt})$~~

~~$AGCDownChgHA_{jxt} = (AGCDownOblig_{jxt} * AGCDownRateHA_{xt})$~~

~~C.3.168.1.16. (b) Spinning Reserve. The ISO will charge the zonal net cost of providing Spinning Reserve capacity that is not self provided by Scheduling Coordinators, in the Hour-Ahead Market, through the application of a charge to each Scheduling Coordinator for the Trading Interval. This charge will be computed by multiplying the Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Spinning Reserve obligation, for which it has not self provided, for the same period. The zonal Spinning Reserve capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to ISO of purchasing Spinning Reserve capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Spinning Reserve bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone, for the Trading Interval, by the total ISO Spinning Reserve MW purchases for the Trading Interval within the Zone. The Hour-Ahead Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{SpinRateHA_{xt} = \frac{\sum_j SpinPayTotalHA_{jxt}}{SpinPurchHA_{xt}}}$$

~~The Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:~~

~~$SpinChgHA_{jxt} = (SpinOblig_{jxt} * SpinRateHA_{xt})$~~

~~C.3.168.1.17. (c) Non-Spinning Reserve. The ISO will charge the zonal net cost of providing Non-Spinning Reserve capacity that is not self provided by Scheduling Coordinators, in the Hour-Ahead Market, through the application of a charge to each Scheduling Coordinator for the Trading Interval. This charge will be computed by multiplying the Non-Spinning Reserve capacity user rate for the concerned Trading Interval by the Scheduling Coordinator's Non-Spinning Reserve obligation, for which it has not self provided, for the same period. The zonal Non-Spinning Reserve capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to ISO of purchasing Non-Spinning Reserve capacity within the Zone less any amounts~~

~~C.3.168.1.18. payable to the ISO by Scheduling Coordinators for Non-Spinning Reserve bought back from the ISO in the Hour-Ahead Market on behalf of resources in the Zone, for the Trading Interval, by the total ISO Non-Spinning Reserve MW purchases for the Trading Interval within the Zone. The Hour-Ahead Non-Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{NonSpinRateHA_{xt} = \frac{\sum_j NonSpinPayTotalHA_{jxt}}{NonSpinObligTotal_{xt}}}$$

~~The Non-Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:~~

$$\cancel{NonSpinChgHA_{jxt} = (NonSpinOblig_{jxt} * NonSpinRateHA_{xt})}$$

~~C 2.2.3 Replacement Reserve~~

~~The user rate per unit of Replacement Reserve obligation for each Settlement Period t for each Zone x shall be as follows:~~

$$\cancel{ReplRate_{xt} = \frac{(PRepResDA_{xt} * OrigReplReqDA_{xt}) + (PRepResHA_{xt} * OrigReplReqHA_{xt})}{OrigReplReqDA_{xt} + OrigReplReqHA_{xt}}}$$

~~where:~~

~~$OrigReplReqDA_{xt}$ = Replacement Reserve requirement net of self-provision in the Day-Ahead Market before consideration of any substitutions pursuant to Section 2.5.3.6.~~

~~$OrigReplReqHA_{xt}$ = Incremental change in the Replacement Reserve requirement net of self-provision between the Day-Ahead Market and the Hour-Ahead Market before consideration of any substitutions pursuant to Section 2.5.3.~~

~~$PRepResDA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Day-Ahead Market for Zone x in Settlement Period t.~~

~~$PRepResHA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Hour-Ahead Market for Zone x in Settlement Period t.~~

~~For each Settlement Period t, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone x:~~

$$\cancel{ReplRate_{xt} * ReplOblig_{jxt}}$$

~~where~~

$$\cancel{ReplOblig_{jxt} = DevReplOblig_{jxt} + RemRepl_{jxt} - SelfProv_{jxt} + NetInterSCTrades_{jxt}}$$

~~$DevReplOblig_{jxt}$ is the Scheduling Coordinator's obligation for deviation Replacement Reserve in Zone x in the Settlement Period t and $RemRepl_{jxt}$ is the Scheduling Coordinator's obligation for remaining Replacement Reserve in Zone x for Settlement Period t.~~

~~$SelfProv_{jxt}$ is Scheduling Coordinator's Replacement Reserve self provision in Zone x for Settlement Period t.~~

~~$NetInterSCTrades_{jxt}$ is the sale of Replacement Reserve less the purchase of Replacement Reserve through Inter-Scheduling Coordinator Trades by Scheduling Coordinator j in Zone x for Settlement Period t.~~

~~Deviation Replacement Reserve for Scheduling Coordinator i in Zone x for Settlement Period t is calculated as follows:~~

~~If $ReplObligTotal_{xt} > TotalDeviations_{xt}$ then:~~

$$\cancel{DevReplOblig_{xjt} = \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]}$$

~~If $ReplObligTotal_{xt} < TotalDeviations_{xt}$ then:~~

$$\cancel{DevReplOblig_{xjt} = \frac{ReplObligTotal_{xt}}{TotalDeviations_{xt}} * \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]}$$

~~where,~~

$$\cancel{TotalDeviations_{xt} = \sum_j \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right)\right]}$$

~~$GenDev_{ijxt}$ = The deviation between scheduled and actual Energy generation for Generator i represented by Scheduling Coordinator I in Zone x during Settlement Period t as referenced in Section 11.2.4.1.~~

~~$LoadDev_{ijxt}$ = The deviation between scheduled and actual Load consumption for resource I represented by Scheduling Coordinator iin Zone x during Settlement Period t as referenced in Section 11.2.4.1.~~

~~$DevReplOblig_{xt}$ is total deviation Replacement Reserve in Zone x for Settlement Period t.~~

~~$ReplObligTotal_{xt}$ is total Replacement Reserve Obligation in Zone x for Settlement Period t.~~

~~Remaining Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:~~

$$\cancel{RemRepl_{xjt} = \frac{MeteredDemand_{jxt}}{TotalMeteredDemand_{xt}} * TotalRemRepl_{xt}}$$

~~where:~~

~~$MeteredDemand_{jxt}$ is the Scheduling Coordinator's total metered Demand excluding exports in Zone x for Settlement Period t.~~

~~$TotalMeteredDemand_{xt}$ is total metered Demand excluding exports in Zone x for Settlement Period t.~~

~~$TotalRemRepl_{xt} = Max[0, ReplObligTotal_{xt} - DevReplOblig_{xt}]$~~

~~C 2.2.4 Rational Buyer Adjustments~~

~~(a) If, in any Settlement Period, no quantity of Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve is purchased in the Day-Ahead Market or the Hour-Ahead Market due to the operation of Section 2.5.3.6 of the ISO Tariff, then in lieu of the user rate determined in accordance with Section C 2.2.1, C 2.2.2, or C 2.2.3, as applicable, the user rate for the affected Ancillary Service for that Settlement Period shall be determined as follows:~~

~~C.3.168.1.19. (i) If the affected market is a Day-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in a Day-Ahead Market for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the lowest MarketClearing Price for the same Settlement Period established in the Day-AheadMarket for another Ancillary Service that meets the requirements for the affected Ancillary Service.~~

~~(ii) If the affected market is an Hour-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Hour-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the user rate for the same Ancillary Service in the Day-Ahead Market in the same Settlement Period.~~

~~(b) With respect to each Settlement Period, in addition to the user rates determined in accordance with Sections C 2.2.1 through C 2.2.3, or Section C 2.2.4(a), as applicable, each Scheduling Coordinator shall be charged an additional amount equal to its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators~~

~~pursuant to Section C 2.1 for the Day-Ahead Market and Hour-Ahead Market and all Zones, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to Sections C 2.2.1 through C 2.2.3, for the Day-Ahead Market and Hour-Ahead Market and all Zones. If total amounts charged to Scheduling Coordinators exceed the total payments to Scheduling Coordinators, each Scheduling Coordinator will be refunded its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve.~~

~~C 2.2.5 Real-Time Market~~

~~(a) The ISO will charge the costs of purchasing Instructed Imbalance Energy output from Dispatched Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Supplemental Energy resources through the Instructed Imbalance Energy settlement process.~~

~~(b) The ISO will charge the costs of purchasing Uninstructed Imbalance Energy (including incremental and decrmental Energy from Generating Units providing Regulation) through the Uninstructed Imbalance Energy settlement process.~~

~~(c) The ISO will charge the costs of Regulation Energy Payment Adjustments as calculated in accordnace with Section 2.5.27.1 of the ISO Tariff, in accordance with SABP 3.1.1(d)~~

~~C 3 Meaning of terms of formulae~~

~~C 3.1 $AGCUpPayDA_{ijxt}$ - $~~

~~The payment for Scheduling Coordinator j for providing Regulation Up capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~$AGCDownPayDA_{ijxt}$ - $~~

~~The payment for Scheduling Coordinator j for providing Regulation Down capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.2 $AGCUpQDA_{ijxt}$ – MW~~

~~The total quantity of Regulation Up capacity provided in the ISO Day-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~$AGCDownQDA_{ijxt}$ – MW~~

~~The total quantity of Regulation Down capacity provided in the ISO Day-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.3 PAGCUpDA~~$_{xt}$~~ - $/MW~~

~~In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those Units subject to the cap for Regulation Up Capacity in the Day-Ahead Market for Trading Interval t in Zone x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Regulation Up Capacity in Zone x for Trading Interval t.~~

~~PAGCDownDA~~$_{xt}$~~ - $/MW~~

~~In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those Units subject to the cap for Regulation Down Capacity in the Day-Ahead Market for Trading Interval t in Zone x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Regulation Down Capacity in Zone x for Trading Interval t.~~

~~C 3.4 AGCUpPayTotalDA~~$_{jxt}$~~ - $~~

~~The total payment for Regulation Up capacity to Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~AGCDownPayTotalDA~~$_{jxt}$~~ - $~~

~~The total payment for Regulation Down capacity to Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.5 AGCUpPayHA~~$_{ijxt}$~~ - $~~

~~The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Regulation Up capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~AGCDownPayHA~~$_{ijxt}$~~ - $~~

~~The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Regulation Down capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.5.1 AGCUpReceiveHA~~$_{ijxt}$~~ - $~~

~~The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead Regulation Up capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~AGCDownReceiveHA~~$_{ijxt}$~~ - $~~

~~The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead Regulation Down capacity which the ISO had~~

~~purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.6 AGCUpQIHA~~ ~~$_{ijxt}$~~ ~~– MW~~

~~The total quantity of incremental (additional to Day-Ahead) Regulation Up capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~AGCDownQIHA~~ ~~$_{ijxt}$~~ ~~– MW~~

~~The total quantity of incremental (additional to Day-Ahead) Regulation Down capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.7 AGCUpQDHA~~ ~~$_{ijxt}$~~ ~~– MW~~

~~The total quantity of decremental (less than Day-Ahead) Regulation Up capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~AGCDownQDHA~~ ~~$_{ijxt}$~~ ~~– MW~~

~~The total quantity of decremental (less than Day-Ahead) Regulation Down capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.7.1 PAGCUpHA~~ ~~$_{xt}$~~ ~~- $/MW~~

~~The Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Regulation Up capacity in the Hour-Ahead Market for Trading Interval t in Zone x. On buyback condition, MCP applies.~~

~~PAGCDownHA~~ ~~$_{xt}$~~ ~~- $/MW~~

~~The Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Regulation Down capacity in the Hour-Ahead Market for Trading Interval t in Zone x. On buyback condition, MCP applies.~~

~~C 3.8 AGCUpPayTotalHA~~ ~~$_{jxt}$~~ ~~- $~~

~~The total payment for incremental (additional to Day-Ahead) Regulation Up capacity to Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from theISO in the Hour-Ahead, Regulation Up capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~AGCDownPayTotalHA~~ ~~$_{jxt}$~~ ~~- $~~

~~The total payment for incremental (additional to Day-Ahead) Regulation Down capacity to Scheduling Coordinator j in the Hour-Ahead Market in~~

~~Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Regulation Down capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.9 AGCUpRateDA~~$_{xt}$ ~~- \$/MW~~

~~The Day-Ahead Regulation Up capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.~~

~~AGCDownRateDA~~$_{xt}$ ~~- \$/MW~~

~~The Day-Ahead Regulation Down capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.~~

~~C 3.10 AGCUpObligTotal~~$_{xt}$ ~~– MW~~

~~The net total Regulation Up obligation in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net total equals the total obligation minus that self-provided.~~

~~AGCDownObligTotal~~$_{xt}$ ~~– MW~~

~~The net total Regulation Down obligation in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net total equals the total obligation minus that self-provided.~~

~~C 3.11 AGCUpChgDA~~$_{jxt}$ ~~- \$~~

~~The Regulation Up charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~AGCDownChgDA~~$_{jxt}$ ~~- \$~~

~~The Regulation Down charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.12 AGCUpOblig~~$_{jxt}$ ~~– MW~~

~~The net Regulation Up obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net obligation equals the obligation minus that self-provided.~~

~~AGCDownOblig~~$_{jxt}$ ~~– MW~~

~~The net Regulation Down obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net obligation equals the obligation minus that self-provided.~~

~~C 3.13 AGCUpRateHA~~$_{xt}$ ~~- \$/MW~~

~~The Hour-Ahead incremental (additional to Day-Ahead) Regulation Up capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.~~

~~$AGCDownRateHA_{xt}$ - $/MW~~

~~The Hour-Ahead incremental (additional to Day-Ahead) Regulation Down capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.~~

~~C 3.14~~ ~~$AGCUpChgHA_{jxt}$ - $~~

~~The incremental (additional to Day-Ahead) Regulation Up charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.~~

~~$AGCDownChgHA_{jxt}$ - $~~

~~The incremental (additional to Day-Ahead) Regulation Down charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.15~~ ~~$EnQPay_{ijxt}$ - $~~

~~The payment for Scheduling Coordinator j for Instructed Imbalance Energy output from a resource i in the Real Time Market in Zone x for Trading Interval t.~~

~~C 3.16~~ ~~[NOT USED]~~

~~C 3.17~~ ~~[NOT USED]~~

~~C 3.18~~ ~~[NOT USED]~~

~~C 3.19~~ ~~$SpinPayDA_{ijxt}$ - $~~

~~The payment for Scheduling Coordinator j for providing Spinning Reserve capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.20~~ ~~$SpinQDA_{ijxt}$ – MW~~

~~The total quantity of Spinning Reserve capacity provided in the Day-Ahead Market by resource i represented by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.20A~~ ~~$REPA_{ijxt}$ - $~~

~~The Regulation Energy Payment Adjustment payable for real time incremental or decremental Energy provided from Regulation resource i of Scheduling Coordinator j in Zone x in Trading Interval t.~~

~~C 3.20B RUP~~~~$_{ijxt}$~~ ~~– MW~~

~~The upward Regulation capacity of Regulation resource i in Zone x included in the Final Schedule for Ancillary Services of Scheduling Coordinator j for Trading Interval t, weighted in proportion to the ISO's need for upward Regulation.~~

~~C3.20C RDN~~~~$_{ijxt}$~~ ~~– MW~~

~~The downward Regulation capacity of Regulation resource i in Zone x included in the Final Schedule for Ancillary Services of Scheduling Coordinator j for Trading Interval t, weighted in proportion to the ISO's need for downward Regulation.~~

~~C 3.20D CUP – number~~

~~The constant established by the ISO and subject to change by resolution of the ISO Governing Board. Initially this shall be set at 1. The ISO may modify the value of CUP within a range of 0-1 either generally in regard to all hours or specifically in regard to particular times of the day, after the ISO Governing Board approves such modifications, by a notice issued by the Chief Executive Officer of the ISO and posted on the ISO Internet "Home Page," at http//www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date and time from which the modification shall take effect, which shall be not less than seven (7) days after the Notice is issued.~~

~~C 3.20E CDN – number~~

~~The constant established by the ISO and subject to change by resolution of the ISO Governing Board. Initially this shall be set at 1. The ISO may modify the value of CDN within a range of 0-1 either generally in regard to all hours or specifically in regard to particular times of the day, after the ISO Governing Board approves such modifications, by a notice issued by the Chief Executive Officer of the ISO and posted on the ISO Internet "Home Page," at http//www.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date and time from which the modification shall take effect, which shall be not less than seven (7) days after the Notice is issued.~~

~~C 3.21 PSpinDA~~~~$_{xt}$~~ ~~-$/MW~~

~~In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Day-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for Spinning Reserve Capacity in Zone x for Trading Interval t. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Spinning Reserve Capacity in Zone x for Trading Interval t.~~

~~C 3.22 SpinPayTotalDA~~ ~~$_{jxt}$~~ ~~- $~~

~~The total payment to Scheduling Coordinator j for Spinning Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.23 SpinPayHA~~ ~~$_{ijxt}$~~ ~~- $~~

~~The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.23.1 SpinReceiveHA~~ ~~$_{Ijxt}$~~ ~~- $~~

~~The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.24 SpinQIHA~~ ~~$_{ijxt}$~~ ~~– MW~~

~~The total quantity of incremental (additional to Day-Ahead) Spinning Reserve capacity provided in the Hour-Ahead Market by resource i represented by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.25 SpinQDHA~~ ~~$_{ijxt}$~~ ~~– MW~~

~~The total quantity of decremental (less than Day-Ahead) Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.25.1 PSpinHA~~ ~~$_{xt}$~~ ~~-$/MW~~

~~The Hour-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Spinning Reserve capacity in Zone x for Trading Interval t. On Buyback condition, MCP applies charge for HA.~~

~~C 3.26 SpinPayTotalHA~~ ~~$_{jxt}$~~ ~~- $~~

~~The total payment to Scheduling Coordinator j for incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead market in Zone x for Trading Interval t.~~

~~C 3.27 SpinRateDA~~ ~~$_{xt}$~~ ~~- $/MW~~

~~The Day-Ahead Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.~~

~~C 3.28 SpinObligTotal~~ $\cancel{_{xt}}$ ~~– MW~~

~~The net total Spinning Reserve capacity obligation in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net total equals the total obligation minus that self-provided.~~

~~C 3.29 SpinChgDA~~ $\cancel{_{jxt}}$ ~~- $~~

~~The Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.30 SpinOblig~~ $\cancel{_{jxt}}$ ~~– MW~~

~~The net Spinning Reserve capacity obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net obligation equals the obligation minus that self-provided.~~

~~C 3.31 SpinRateHA~~ $\cancel{_{xt}}$ ~~- $/MW~~

~~The Hour-Ahead incremental (additional to Day-Ahead) Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.~~

~~C 3.32 SpinChgHA~~ $\cancel{_{jxt}}$ ~~- $~~

~~The incremental (additional to Day-Ahead) Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.33 NonSpinPayDA~~ $\cancel{_{ijxt}}$ ~~- $~~

~~The payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.34 NonSpinQDA~~ $\cancel{_{ijxt}}$ ~~– MW~~

~~The total quantity of Non-Spinning Reserve capacity provided from resource i in the Day-Ahead Market by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.35 PNonSpinDA~~ $\cancel{_{xt}}$ ~~- $/MW~~

~~In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Day-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for Non-Spinning Reserve Capacity for Trading Interval t in Zone x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Non-Spinning Reserve Capacity in Zone x for Trading Interval t.~~

~~C 3.36 NonSpinPayTotalDA~~$_{jxt}$ ~~- $~~

~~The total payment to Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.37 NonSpinPayHA~~$_{ijxt}$ ~~- $~~

~~The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.37.1 NonSpinReceiveHA~~$_{ijxt}$ ~~- $~~

~~The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.38 NonSpinQIHA~~$_{ijxt}$ ~~– MW~~

~~The total quantity of incremental (additional to Day-Ahead) Non-Spinning Reserve capacity provided from resource i in the Hour-Ahead Market by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.39 NonSpinQDHA~~$_{ijxt}$ ~~– MW~~

~~The total quantity of decremental (less than Day-Ahead) Non-Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.39.1 PNonSpinHA~~$_{xt}$ ~~- $/MW~~

~~The Hour-Ahead zonal Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Non-Spinning Reserve capacity for Trading Interval t in Zone x. On Buyback condition, MCP applies.~~

~~C 3.40 NonSpinPayTotalHA~~$_{jxt}$ ~~- $~~

~~The total payment to Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead market in Zone x for Trading Interval t.~~

~~C 3.41 NonSpinRateDA~~$_{xt}$ ~~- $/MW~~

~~The Day-Ahead Non-Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.~~

~~C 3.42 NonSpinObligTotal~~$\cancel{_{xt}}$ ~~– MW~~

~~The net total Non-Spinning Reserve capacity obligation in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net total obligation equals the total minus that self-provided.~~

~~C 3.43 NonSpinChgDA~~$\cancel{_{jxt}}$ ~~- $~~

~~The Non-Spinning Reserve Capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.44 NonSpinOblig~~$\cancel{_{jxt}}$ ~~– MW~~

~~The net Non-Spinning Reserve capacity obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net obligation is the obligation minus that self-provided.~~

~~C 3.45 NonSpinRateHA~~$\cancel{_{xt}}$ ~~- $/MW~~

~~The Hour-Ahead incremental (additional to Day-Ahead) Non-Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.~~

~~C 3.46 NonSpinChgHA~~$\cancel{_{jxt}}$ ~~- $~~

~~The incremental (additional to Day-Ahead) Non-Spinning Reserve Capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.47 NonSpinObligHA~~$\cancel{_{jxt}}$ ~~– MW~~

~~The net incremental (additional to Day-Ahead) Non-Spinning Reserve capacity obligation in the Hour-Ahead Market for Scheduling Coordinator j in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net obligation is the obligation minus that self-provided.~~

~~C 3.48 ReplPayDA~~$\cancel{_{ijxt}}$ ~~- $~~

~~The payment for Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.49 ReplQDA~~$\cancel{_{ijxt}}$ ~~– MW~~

~~The total quantity of Replacement Reserve capacity provided in the Day-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.50 PReplDA~~$\cancel{_{xt}}$ ~~-$/MW~~

~~In the case of Capacity made available in accordance with ISO's Final Day-Ahead Schedules, the Day-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units not subject to the cap for Replacement Reserve Capacity in Zone~~

~~x for Trading Interval t. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Replacement Reserve Capacity in Zone x for Trading Interval t.~~

~~C 3.51~~ ~~$ReplPayTotalDA_{jxt}$ - \$~~

~~The total payment to Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.51.1~~ ~~$ReplReceiveHA_{ijxt}$ - \$~~

~~The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Replacement Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in the Zone x for Trading Interval t.~~

~~C 3.52~~ ~~$ReplPayHA_{ijxt}$ - \$~~

~~The payment for Scheduling Coordinator j for providing of incremental (additional to Day-Ahead) Replacement Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.~~

~~C 3.53~~ ~~$ReplQIHA_{ijxt}$ – MW~~

~~The total quantity of incremental (additional to Day-Ahead) Replacement Reserve capacity provided in the Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.54~~ ~~$ReplQDHA_{ijxt}$ – MW~~

~~The total quantity of decremental (less than Day-Ahead) Replacement Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.~~

~~C 3.54.1~~ ~~$PReplHA_{xt}$ -\$/MW~~

~~The Hour-Ahead Market Clearing Price for Non-FERC jurisdictional units or the bid price for FERC jurisdictional units for incremental (additional to Day-Ahead) Replacement Reserve capacity in Zone x for Trading Interval t. On Buyback condition, MCP applies.~~

~~C 3.55~~ ~~$ReplPayTotalHA_{jxt}$ - \$~~

~~The total payment to Scheduling Coordinator j for providing of incremental (additional to Day-Ahead) Replacement Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Replacement Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x from Trading Interval t.~~

~~C 3.56~~ ~~$ReplRateDA_{xt}$ - \$/MW~~

~~The Day-Ahead Replacement Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.~~

~~C 3.57~~ ~~$ReplChgDA_{jxt}$ - \$~~

~~The Replacement Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.~~

~~C 3.58~~ ~~$ReplRateHA_{xt}$ – \$/MW~~

~~The Hour-Ahead incremental (additional to Day-Ahead) Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.~~

~~C 3.59~~ ~~$ReplChgHA_{jxt}$ - \$~~

~~The incremental (additional to Day-Ahead) Replacement Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in zone x for Trading Interval t.~~

~~C 3.60~~ ~~$ReplObligTotal_{xt}$ – MW~~

~~The net total Replacement Reserve capacity obligation in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net total obligation is the total obligation minus that self-provided.~~

~~C 3.61~~ ~~$ReplPayTotal_{jxt}$ - \$~~

~~The total payment to Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead and Hour-Ahead Markets in zone x for Trading Interval t.~~

~~C 3.62~~ ~~$PavgRepl_{xt}$ - \$/MW~~

~~The average price paid for Replacement Reserve capacity in the Day-Ahead Market and the Hour-Ahead Market in Zone x in Trading Interval t.~~

~~C 3.63~~ ~~$UnDispReplChg_{jxt}$ - \$~~

~~The undispatched Replacement Reserve Capacity charge for Scheduling Coordinator j in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t.~~

~~C 3.64~~ ~~$ReplOblig_{jxt}$ – MW~~

~~The Replacement Reserve capacity obligation in the Day-Ahead and Hour-Ahead Markets for Scheduling Coordinator j in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol.~~

~~C 3.65~~ ~~$ReplQDisp_{xt}$ – MWh~~

~~The Dispatched Replacement Reserve capacity in the Day-Ahead Market in Zone x in Trading Interval t.~~

~~C 3.66~~ ~~$AGCUpPurchDA_{xt}$ – MW~~

~~The total quantity of Regulation Up capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.~~

~~$AGCDownPurchDA_{xt}$ – MW~~

~~The total quantity of Regulation Down capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.~~

~~C 3.67~~ ~~$SpinPurchDA_{xt}$ – MW~~

~~The total quantity of Spinning Reserve capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.~~

~~C 3.68~~ ~~$NonSpinPurchDA_{xt}$ – MW~~

~~The total quantity of Non-Spinning Reserve capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.~~

~~C 3.69~~ ~~$AGCUpPurchHA_{xt}$ – MW~~

~~The net quantity of Regulation Up capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.~~

~~$AGCDownPurchHA_{xt}$ – MW~~

~~The net quantity of Regulation Down capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.~~

~~C 3.70~~ ~~$SpinPurchHA_{xt}$ – MW~~

~~The net quantity of Spinning Reserve capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.~~

~~C 3.71~~ ~~$NonSpinPurchDA_{xt}$ – MW~~

~~The net quantity of Non-Spinning Reserve capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.~~

APPENDIX D. IMBALANCE ENERGY CHARGE COMPUTATION

D.1 Scheduled Energy

"Scheduled Energy" is the Energy produced or consumed in each Dispatch Interval according to the Final Hour-Ahead Schedule as modified to account for Schedule changes between consecutive hours. A zero (0) MW Final Hour-Ahead Schedule is assumed by default for resources not scheduled in the Day-Ahead or Hour-Ahead Markets. All Schedule changes between consecutive hours shall be performed by a smooth linear ramp ("Scheduling Ramp") between the relevant Final Hour-Ahead Schedules. The Scheduling Ramp specifications, i.e., start time, end time, duration, and maximum ramp, may differ by resource depending on the resource's ramping ability and shall be specified by the ISO in the ISO Home Page. The ISO may periodically modify the Scheduling Ramp specifications as needed 24 hours after notifying Market Participants. The Scheduling Ramp specifications shall be taken into account in all scheduling and Dispatch tools used by the ISO to produce feasible Schedules and Dispatch Instructions consistent with the resource operational capabilities and constraints.

The Final Hour-Ahead Schedule and the associated Scheduling Ramp define the "Scheduled Operating Point (SOP)," which is the expected operating point of a resource as a function of time when no Dispatch Instructions are issued to that resource.

The Scheduled Energy shall be calculated in each Dispatch Interval as the integral of the SOP as follows:

$$SE_{i,h,k} = \int_{t=(k-1)T}^{kT} SOP_{i,h}(t)\, dt \qquad (1)$$

where:

- T is the time index;
- I is the resource index;
- H is the hour index;
- K is the Dispatch Interval index;
- $SE_{i,h,k}$ is the Scheduled Energy from resource i during Dispatch Interval k of hour h;

hour *h*;

$SOP_{i,h}(t)$ is the SOP of resource *i* during hour *h* as a function of time; and

T is the duration of the Dispatch Interval (10 minutes).

D.2 Metered Energy

"Metered Energy" is Energy produced or consumed in real time during each Dispatch Interval. Metered Energy for ISO-Metered Entities is obtained from actual meter data that are aggregated for the duration of each Dispatch Interval. Metered Energy for non-ISO-Metered Entities is obtained from hourly meter data that are evenly distributed to the Dispatch Intervals of each hour. Meter data do not exist for individual System Resources. Therefore, Metered Energy for System Resources is obtained by inference from their Scheduled Energy and the Imbalance Energy that they are expected to produce or consume by responding to Dispatch Instructions.

D.3 Imbalance Energy

Imbalance Energy is real-time Energy deviation from Scheduled Energy. Positive Imbalance Energy is Energy that is produced in excess of Scheduled Energy or Scheduled Energy that is not consumed.. Negative Imbalance Energy is Scheduled Energy that is not produced or Energy that is consumed in excess of Scheduled Energy. Imbalance Energy shall be measured, calculated, and settled in each Dispatch Interval for each resource separately. Imbalance Energy is composed of Instructed Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted For Energy.

D.3.1 Instructed Imbalance Energy

Instructed Imbalance Energy is Energy produced or consumed as the result of responding to Dispatch Instructions. Dispatch Instructions specify the operating point where a dispatched resource is instructed to be after accounting for any start-up time (if the resource is off-line) and/or ramping with the relevant maximum ramp rate, as registered in the Master File. The start-up time must be less than ten (10) minutes for Non-Spinning Reserve. The Dispatch Instructions and the relevant start-up times and ramp rates define the Dispatch Operating Point (DOP) of resources in real time. The DOP of resources that are not dispatched defaults to the respective SOP.

Dispatch Instructions include pre-dispatch instructions issued after the Day-Ahead and Hour-Ahead Residual Unit Commitment Processes, pre-dispatch instructions issued after the Hourly Pre-Dispatch process, and Dispatch Instructions issued within the hour. Hourly Pre-dispatch instructions are for a full hour. The associated Energy deviations are settled as Instructed Imbalance Energy. Dispatch Instructions issued within the hour are 10-minute (or until the end of the hour, whichever less) instructions issued after a SCED execution or after an Exceptional Dispatch. Such instructions issued to resources with start-up times longer than ten minutes shall be issued sufficiently in advance to allow the resource time to start up. Dispatch Instructions also include implicit "end-of-hour instructions" that instruct a resource to return to its Final Hour-Ahead Schedule for the next hour and apply by default at the end of the hour to all resources that are not pre-dispatched for the next hour or not dispatched for the first Dispatch Interval of the next hour. All Dispatch Instructions are deemed delivered. Instructed Imbalance Energy shall be calculated in each Dispatch Interval as the integral of the difference between the DOP and the SOP as follows:

$$IIE_{i,h,k} = \int_{t=(k-1)T}^{kT} \left(DOP_{i,h}(t) - SOP_{i,h}(t) \right) dt = \int_{t=(k-1)T}^{kT} DOP_{i,h}(t)\, dt - SE_{i,h,k} \qquad (2)$$

where:

$IIE_{i,h,k}$ is the Instructed Imbalance Energy from resource *i* during Dispatch Interval *k* of hour *h*; and

$DOP_{i,h}(t)$ is the DOP of resource *i* during hour *h* as a function of time.

Positive Instructed Imbalance Energy shall be paid the relevant Dispatch Interval Locational Marginal Price and negative Instructed Imbalance Energy shall be charged the relevant Dispatch Interval Locational Marginal Price. In algebraic terms, adopting the injection convention (injections are positive whereas ejections are negative), the Instructed Imbalance Energy charge is given by:

$$IIEC_{i,h,k} = -IIE_{i,h,k}\, LMP_{i,h,k} \qquad (3)$$

where:

$IIEC_{i,h,k}$ is the Instructed Imbalance Energy charge for resource *i* during Dispatch Interval *k* of hour *h*; and

$LMP_{i,h,k}$ is the LMP at the Location of resource *i* during Dispatch Interval *k* of hour *h*, as determined in accordance with Section 31.4.3.2.4.

Side payments may apply in addition to the Instructed Imbalance Energy charge as set forth in Section 31.4.3.4.4.

D.3.2 Uninstructed Imbalance Energy

Uninstructed Imbalance Energy is Energy produced or consumed due to deviations from the DOP. Uninstructed Imbalance Energy shall be calculated in each Dispatch Interval as the difference between Metered Energy and the integral of the DOP over that Dispatch Interval as follows:

$$UIE_{i,h,k} = ME_{i,h,k} - \int_{t=(k-1)T}^{kT} DOP_{i,h}(t)\,dt = ME_{i,h,k} - \left(SE_{i,h,k} + IIE_{i,h,k}\right) \tag{4}$$

where:

$UIE_{i,h,k}$ is the Uninstructed Imbalance Energy from resource *i* during Dispatch Interval *k* of hour *h*; and

$ME_{i,h,k}$ is the Metered Energy from resource *i* during Dispatch Interval *k* of hour *h*.

Positive Uninstructed Imbalance Energy shall be paid the relevant Dispatch Interval Locational Marginal Price and negative Uninstructed Imbalance Energy shall be charged the relevant Dispatch Interval Locational Marginal Price. In algebraic terms, adopting the injection convention, the Uninstructed Imbalance Energy charge is given by:

$$UIEC_{i,h,k} = -UIE_{i,h,k}\ LMP_{i,h,k} \tag{5}$$

where:

$UIEC_{i,h,k}$ is the Uninstructed Imbalance Energy charge for resource *i* during Dispatch Interval *k* of hour *h*.

Uninstructed Deviation Penalties may apply in addition to the Uninstructed Imbalance Energy charge as set forth in Section 11.2.4.1.2.

D.3.3 Unaccounted For Energy

Unaccounted For Energy (UFE) shall be calculated for each UDC Service Area and for each Dispatch Interval as the difference between the net Energy delivered into the UDC Service Area, adjusted for UDC Service Area Transmission Losses, and the total metered Demand within the UDC Service Area. The net Energy delivered into the UDC Service Area is obtained by aggregating the meter data of all UDC Interconnections in the import direction and the Metered Energy from all Generators within the UDC Service Area. The total metered Demand within the UDC Service Area is obtained by aggregating the Metered Energy from all Loads within the UDC Service Area. The UDC Service Area Transmission Losses are obtained by the State Estimator function of the Energy Management System as set forth in Section 31.4.3.2.1. Before the State Estimator is available, the ISO shall estimate UDC Service Area Transmission Losses using power flow calculations.

In algebraic terms, adopting the injection convention, the UFE is given by:

$$UFE_{j,h,k} = \sum_{l \in UDC_j} I_{l,h,k} + \sum_{i \in UDC_j} ME_{i,h,k} - TL_{j,h,k} \qquad (6)$$

where:

- J is the UDC index;
- L is the UDC Interconnection index;
- UDC_j is the set of UDC Interconnections into UDC Service Area j or the set of Generators and Loads within UDC Service Area j;
- $UFE_{j,h,k}$ is the UFE in UDC Service Area j during Dispatch Interval k of hour h;
- $I_{l,h,k}$ is the net import into UDC Service Area j from UDC Interconnection l during Dispatch Interval k of hour h; and
- $TL_{l,h,k}$ is the transmission loss in UDC Service Area j during Dispatch Interval k of hour h.

The UFE in each UDC Service Area shall be distributed to all Loads and exports within the UDC Service Area in proportion to their Metered Energy as follows:

$$UFE_{i,h,k} = UFE_{j,h,k} \frac{ME_{i,h,k}}{\sum_{i \in UDC_j} ME_{i,h,k}} \tag{7}$$

where:

i is the index of Loads within UDC Service Area j or exports from UDC Service Area j outside the ISO Control Area; and

$UFE_{i,h,k}$ is the UFE allocated to Load within the UDC Service Area j or exports from UDC Service Area j outside the ISO Control Area during Dispatch Interval k of hour h;

Positive UFE shall be paid the relevant Dispatch Interval Locational Marginal Price and negative UFE shall be charged the relevant Dispatch Interval Locational Marginal Price. In algebraic terms, adopting the injection convention, the UFE charge is given by:

$$UFEC_{i,h,k} = -UFE_{i,h,k}\, LMP_{i,h,k} \tag{8}$$

where:

$UFEC_{i,h,k}$ is the UFE charge for Load i within UDC Service Area j or export i from UDC Service Area j outside the ISO Control Area during Dispatch Interval k of hour h.

Uninstructed Deviation Penalties shall not apply to UFE.

D.4 Hourly Ex Post Price

For each Settlement Period and Location where Instructed Imbalance Energy is procured, the ISO shall calculate the Hourly Ex Post Price as the weighted average of the relevant six Dispatch Interval Locational Marginal Prices during the Settlement Period. The weights shall be the Instructed Imbalance Energy procured during the corresponding Dispatch Intervals, as follows:

$$HEPP_{i,h,k} = \frac{\sum_{k=1}^{6} \left(\left| IIE_{i,h,k} \right| LMP_{i,h,k} \right)}{\sum_{k=1}^{6} \left| IIE_{i,h,k} \right|} \tag{9}$$

where:

$HEPP_{i,h,k}$	is the Hourly Ex Post Price at Location *i* during Dispatch Interval *k* of hour *h*; and
$IIE_{i,h,k}$	is the total Instructed Imbalance Energy procured at Location *i* during Dispatch Interval *k* of hour *h*.

~~APPENDIX D~~

~~IMBALANCE ENERGY CHARGE COMPUTATION~~

~~D 1 Purpose of charge~~

~~The Imbalance Energy charge is the term used for allocating the cost of not only the Imbalance Energy (the differences between scheduled and actual Generation and Demand), but also any Unaccounted for Energy (UFE) and any errors in the forecasted Transmission Losses as represented by the GMMs. Any corresponding cost of Dispatched Replacement Reserve Capacity that is not allocated as an Ancillary Service is also included along with the Imbalance Energy charge.~~

~~D 2 Fundamental formulae~~

~~D 2.1.1 Uninstructed Imbalance Energy Charges on Scheduling Coordinators~~

~~Uninstructed Imbalance Energy attributable to each Scheduling Coordinator in each Settlement Period in the relevant Zone shall be deemed to be sold or purchased, as the case may be, by the ISO and charges or payments for Uninstructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each BEEP Interval of each Settlement Period calculated in accordance with the following formulae:~~

$$DevC = \sum_i GenDevC_i + \sum_i LoadDevC_i + \sum_q ImpDevC_q + \sum_q ExpDevC_q + UFEC$$

$$ASSEDevC = \sum_i ASSEGenDevC_i + \sum_i ASSELoadDevC_i + \sum_q ASSEImpDevC_q$$

$$\cancel{DevC_{bjxt} = NetDev_{bjxt} * BIP_{bxt}}$$

~~Where:~~

$$\cancel{NetDev_{bjxt} = \left[\sum_i GenDev_{bixt} - \sum_i LoadDev_{bixt} + \sum_q ImpDev_{bq\text{-}xt} - \sum_q ExpDev_{bq\text{-}xt}\right]}$$

~~If $NetDev_{bjxt}$ < 0, then~~

~~BIP_{bxt} = BEEP Interval Price for decremental Energy for BEEP Interval b in Settlement Period t.~~

~~If $NetDev_{bjxt}$ > 0, then~~

~~BIP_{bxt} = BEEP Interval Price for incremental Energy in Zone x for BEEP Interval b in Settlement Period t.~~

~~The deviation quantity between scheduled and actual Energy Generation for Generator i represented by Scheduling Coordinator j in Zone x during each BEEP Interval b of each Settlement Period t is calculated as follows:~~

$$GenDev_{ixbt} = \left[\left(G_{sb}\right) * GMM_f - \left[\left(G_a - G_{b,adj}\right) * GMM_a - G_{b,a/s} - G_{b,s/e}\right] - \frac{UnavailAncServMW_{bx}}{HBI} \right]$$

~~Where:~~

~~If the BEEP Interval Ex Post Price for decremental Energy is negative, then:~~

~~*UnavailAncServMW*~~$_{ix}$ ~~= 0~~

~~If the BEEP Interval Ex Post Price for decremental Energy is greater than or equal to zero, then:~~

$$UnavailAncServMW_{ix} = Max\ [\ (G_{i,\ oblig} - G_{a/s*6})\ Min[0,\ Pmax - G_{a*6} - (G_{i,\ oblig} - G_{a/s}*6))]$$

~~The value of~~ G_a ~~for Generation scheduled on behalf of Participating Generators for each BEEP Interval in each Settlement Period shall be the actual meter data aggregated on a 10-minute basis. The value of~~ G_{sb} ~~for Generation scheduled on behalf of Participating Generators for each BEEP Interval in each Settlement Period shall be determined as follows for BEEP Intervals 2 through 5:~~

$$G_{s,b} = \frac{G_s}{6}$$

~~For BEEP Interval 1 and BEEP Interval 6, implicit Dispatch instructions for ramping will be applied to adjust the Schedules attributed to those BEEP Intervals as follows:~~

$$G_{s,1} = \left(\frac{G_s}{6}\right) - \left(\frac{(G_s - G_{s-1})}{24}\right)$$

$$G_{s,6} = \left(\frac{G_s}{6}\right) + \left(\frac{(G_{s+1} - G_s)}{24}\right)$$

~~The value of~~ G_s ~~and~~ G_a ~~for Generation which has not undertaken in writing to be bound by the ISO Tariff in accordance with Article 5 shall be determined as follows for all six BEEP Intervals:~~

$$G_{s,b} = \frac{G_{s,t}}{6}$$

$$G_a = \frac{G_{at}}{6}$$

~~The deviation quantity between scheduled and actual Load consumption for Load i represented by Scheduling Coordinator j in Zone x for each BEEP Interval of each Settlement Period t is calculated as follows:~~

$$LoadDev_{ibxt} = L_{sb} - \left[\left(L_a - L_{b,adj} \right) + L_{b,a/s} + L_{b,s/e} - \frac{UnavailDispLoadMW_{bx}}{HBI} \right]$$

~~Where;~~

~~If the BEEP Interval Ex Post Price for decremental Energy is negative, then:~~

$UnavailDispLoadMW_{ix} = 0$

~~If the BEEP Interval Ex Post Price for decremental Energy is greater than or equal to zero, then:~~

$UnavailDispLoadMW_{ix} = Max[0, [((L_{i,\,oblig}) - L_{a/s}*6) - (L_a*6)]]$

~~The value of $L_{b,a/s}$, $L_{b,s/e}$ and L_{adj} are determined on a 10-minute basis. The value of L_a for Load scheduled on behalf of Participating Loads for each BEEP Interval in each Settlement Period shall be the actual meter data aggregated on a 10-minute basis. The value of L_{sb} for Load scheduled on behalf of Participating Loads for each BEEP Interval in each Settlement Period t, shall be determined as follows:~~

~~For BEEP Intervals 2 through 5,~~

$$L_{sb} = \frac{L_s}{6}$$

~~For BEEP Interval 1 and BEEP Interval 6, implicit Dispatch instructions for ramping will be applied to adjust the schedules attributed to those BEEP Intervals as follows:~~

$$L_{s,1} = \left(\frac{L_s}{6} \right) - \left(\frac{(L_s - L_{s-1})}{24} \right)$$

$$L_{s,6} = \left(\frac{L_s}{6} \right) + \left(\frac{(L_{s+1} - L_s)}{24} \right)$$

~~The value of L_{sb} and L_a for Loads that are not Participating Loads shall be determined as follows for all six BEEP Intervals:~~

$$L_{sb} = \frac{L_s}{6}$$

$$L_a = \frac{L_{at}}{6}$$

~~L_{at} is Load i hourly metered quantity for Settlement Period t.~~

~~The deviation quantity between forward scheduled and Real Time adjustments to Energy imports[*], adjusted for losses, for Scheduling~~

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[*] Note that this deviation is a difference between a forward Market value and a Real Time value. It is not inadvertent energy.

~~Point q represented by Scheduling Coordinator j into zone x during each BEEP Interval of each Settlement Period is calculated as follows:~~

$$\cancel{ImpDev_q = I_{sb} * GMM_{fq} - [(I_a + I_{b,a/s} - I_{b,adj}) * GMM_{ahq}] + I_{b,a/s}}$$

~~The values of $I_{b,a/s}$, I_a and $I_{b,adj}$ are determined on a 10-minute basis. The value of I_{sb} shall be determined as follows:~~

~~For BEEP Intervals 1 through 6,~~

$$\cancel{I_{sb} = \frac{I_s}{6}}$$

~~The deviation quantity between forward scheduled and Real Time adjustments to Energy exports* for Scheduling Point q represented by Scheduling Coordinator j from Zone x for each BEEP Interval for each Settlement Period t is calculated as follows:~~

$$\cancel{ExpDev_q = E_{s,b} - E_a - E_{adj,b}}$$

~~The values of E_a and $E_{b,adj}$ are determined on a 10-minute basis. The value of $E_{s,b}$ shall be determined as follows:~~

~~For BEEP Intervals 1 through 6,~~

$$\cancel{E_{sb} = \frac{E_s}{6}}$$

~~The Hourly Ex Post Price applicable to uninstructed deviations in Settlement Period t in each zone will equal the Energy weighted average of the BEEP Interval charges in each zone, calculated as follows:~~

$$\cancel{P_{xt} = \frac{(\sum_{ji} |MWh_{jix}| * BIP_{ix})}{\sum_{ji} |MWh_{jix}|}}$$

~~Where:~~

~~BIP_{ix} = BEEP Interval Ex Post Prices to be used for settlement of Uninstructed Imbalance Energy. The BEEP Interval Price for incremental Energy will be charged to decremental uninstructed deviations in that interval, and the BEEP Interval Price for incremental Energy will be charged to incremental uninstructed deviations in that interval.~~

~~P_{xt} = the Hourly Ex Post Price in Zone x~~

~~MWH_{jix} = the Instructed Imbalance Energy for Scheduling Coordinator j for the BEEP Interval i in Zone x~~

~~D 2.1.2 Instructed Imbalance Energy Charges on Scheduling Coordinators~~

~~Implicit Dispatch instructions for ramping Energy shall be calculated~~

~~based on Final Hour Ahead Schedules for Energy to result in a linear ramp by all Participating Generators and Participating Loads beginning 10 minutes prior to the start, and ending 10 minutes after the start of~~

~~each Settlement Period. Ramping Energy shall be deemed delivered and settled at a price of zero dollars per MWh.~~

~~The amount of Instructed Imbalance Energy to be delivered in each BEEP Interval will be determined based on the ramp rates and time delays bid in accordance with SBP 5 and 6. Payment due a Load, Generator, Import or Export for Instructed Imbalance Energy to be delivered in a BEEP Interval shall be calculated based on the actual Energy delivered to the ISO Grid in accordance with the Dispatch instruction.~~

~~Instructed Imbalance Energy by an Import or Export is deemed delivered. The actual Energy delivered by a Load or Generator in response to Dispatch instructions will be determined by first attributing Energy deviations to any Energy associated with redispatch of that Load or Generation in that BEEP Interval according to Section 7.2.6.2, or to Dispatch orders to be settled in accordance with Section 11.2.4.2. If instructions for both incremental and decremental Energy are issued in a BEEP Interval, then any instructions described in the previous sentence for decremental Energy, together with any decremental Dispatch instructions on Supplemental Energy, shall be deemed delivered.~~

~~Any remaining deviation will then be sequentially attributed to Instructed Imbalance Energy, first from Supplemental Energy, then from Replacement Reserve, then from Non-Spinning Reserve, and then from Spinning Reserve in that BEEP Interval.~~

~~Residual Instructed Imbalance Energy arising due to Dispatch instructions shall be priced based on the applicable BEEP Interval Ex Post Price for the BEEP Interval to which the Dispatch instruction applied. If Instructed Imbalance Energy is to be delivered in the last BEEP Interval of the hour preceeding the Settlement Period to which a Dispatch instruction applies shall be settled at the applicable BEEP Interval Ex Post Price for the first BEEP Interval of the Settlement Period for which the bid was submitted.~~

~~Subject to the above conditions, the Instructed Imbalance Energy charge for each BEEP Interval b of each Settlement Period t for Scheduling Coordinator j for Zone x is calculated using the following formulas:~~

~~The instructed Generation deviation payment/charge is calculated as follows:~~

$\cancel{IGDC_{ib} = G_{ib} * P_b}$

~~The instructed Load deviation payment/charge is calculated as follows:~~

$\cancel{ILDC_{ib} = L_{ib} * P_b}$

~~The instructed import deviation payment/charge is calculated as follows:~~

$\cancel{IIDC_{qb} = I_{qb} * P_b}$

~~D 2.2 Unaccounted for Energy Charge~~

~~The Unaccounted for Energy Charge on Scheduling Coordinator j for each BEEP Interval of each Settlement Period t for each relevant Zone is calculated in the following manner:~~

~~The UFE for each utility service territory *k* is calculated as follows,~~

$$E_{UFE\_UDC\_k} = \left(I_k - E_k + G_k - \left(RTM_k + LPM_k\right) - TL_k\right)$$

~~The Transmission Loss calculation for each BEEP Interval of each Settlement Period t per relevant Zone for each utility service territory k is calculated as follows,~~

$$TL_k = Total\_TLRC_{Losses} * (UDC_k\_Branch_{Losses} / Total\_Branch_{Losses})$$

~~Where:~~

$$Total\_TLRC_{Losses} = \sum\left[G_a * \left(1 - GMM_a\right)\right] + \sum\left[I_a\left(1 - GMM_{aq}\right)\right]$$

$$Total\_Branch_{Losses} = \frac{\left(\sum UDC_k - Branch_{Losses}\right)}{6}$$

~~Each metered demand point, either ISO grid connected or connected through a UDC, is allocated a portion of the UFE as follows:~~

$$E_{UFE\_z} = \frac{D_z}{\sum_z D_z} E_{UFE\_UDC\_k}$$

~~The UFE charge for Scheduling Coordinator j for each BEEP Interval b of each Settlement Period t per relevant Zone is then,~~

$$UFEC_j = \left(\sum_z E_{UFE\_Z}\right) * BIP_{bxt}$$

~~D 3 Meaning of terms of formulae~~

~~D 3.1~~ ~~IEC_j – \$~~

~~The Imbalance Energy charge on Scheduling Coordinator j in Trading Interval t for each relevant Zone.~~

~~**D 3.2 GenDev$_i$ – MWh**~~

~~The deviation between scheduled and actual Energy Generation for Generator i represented by Scheduling Coordinator j in Zone x during Trading Interval t.~~

~~**D 3.3 LoadDev$_i$ – MWh**~~

~~The deviation between scheduled and actual Load consumption for Generator i represented by Scheduling Coordinator j in Zone x during Trading Interval **t.**~~

~~**D 3.4 ImpDev$_q$ – MWh**~~

~~The deviation between forward scheduled and Real Time adjustments to Energy imports, as adjusted for losses, for Scheduling Point q represented by Scheduling Coordinator j into Zone x during Trading Interval t.~~

~~**D 3.5 ExpDev$_q$ – MWh**~~

~~The deviation between forward scheduled and Real Time adjustments to Energy exports for Scheduling Point q represented by Scheduling Coordinator j~~

~~from Zone x during Trading Interval t.~~

~~**D 3.6 G$_s$ – MWh**~~

~~The total scheduled Generation of Scheduling Coordinator j for Generator i in Settlement Period t as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.~~

~~**D 3.6.1 G$_{s-1}$**~~

~~The total scheduled Generation of Scheduling Coordinator j for Generator i in settlement Period t-1 as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.~~

~~**D 3.6.2 G$_{s+1}$**~~

~~The total scheduled Generation of Scheduling Coordinator j for Generator i in settlement Period t+1 as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.~~

~~**D 3.6.3 G$_{b,adj}$**~~

~~Is Deviation in real time ordered by the ISO in BEEP Interval b according to Section 7.2.6.2, or for settlement according to Section 11.2.4.2.~~

~~**D 3.7 G$_{at}$ - MWh**~~

~~The total actual metered Generation of Scheduling Coordinator j for Generator i in Settlement Period t.~~

~~D 3.8 G_{adj} – MWh~~

~~Deviations in real time ordered by the ISO for purposes such as Congestion Management.~~

~~**D 3.9 $G_{a/s}$ – MWh**~~

~~The Energy generated from Ancillary Service resource i due to ISO dispatch instructions. This value will be calculated based on the projected impact of the Ancillary Services dispatch instruction(s) over the time period within the Trading Interval for which such Ancillary Services dispatch instruction(s) applies.~~

~~**D 3.9.1 $G_{s/e}$ -MWh**~~

~~The Energy generated from Supplemental Energy resource i due to ISO dispatch instructions. This value will be calculated based on the projected impact of the Supplemental Energy dispatch instruction(s) over the time period within the Trading Interval for which such Supplemental Energy dispatch instruction(s) applies.~~

~~**D 3.10 GMM_f – fraction**~~

~~The forecasted Generation Meter Multiplier (GMM) for Generator i as provided to the Scheduling Coordinator by the ISO in advance of the operation of the Day-Ahead Market.~~

~~**D 3.11 GMM_{fq} – fraction**~~

~~The forecasted Generation Meter Multiplier for an Energy import at Scheduling Point q as provided to the Scheduling Coordinator by the ISO in advance of the Day-Ahead Market.~~

~~**D 3.12 GMM_{ah} – fraction**~~

~~The final forecasted Generation Meter Multiplier (GMM) for a Generator i as calculated by the ISO at the hour-ahead stage (but after close of the Hour-Ahead Market).~~

~~**D 3.13 GMM_{ahq} – fraction**~~

~~The forecasted Generation Meter Multiplier for an Energy import at Scheduling Point q as provided to the Scheduling Coordinator by the ISO after close of the Hour-Ahead Market.~~

~~**D 3.14 L_S – MWh**~~

~~The total scheduled Demand of Scheduling Coordinator j for Demand i in Settlement Period t as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.~~

~~D 3.15 L_a – MWh~~

~~The total actual metered Demand of Scheduling Coordinator j for Demand i in BEEP Interval b of Settlement Period t.~~

~~D 3.15.1 L_{at} – MWh~~

~~The total actual metered Demand of Scheduling Coordinator j for Demand i in Settlement Period t.~~

~~**D 3.15.2 $L_{b,adj}$**~~

~~Is Deviation in real time ordered by the ISO in BEEP Interval b according to Section 7.2.6.2, or for settlement according to Section 11.2.4.2.~~

~~**D 3.16 [Not Used]**~~

~~**D 3.17 $L_{a/s}$ – MWh**~~

~~The Energy reduction by curtailable Load due to ISO dispatch of Ancillary Services from such curtailable Load (i.e., Load bidding into the Ancillary Services markets). This value will be calculated based on the projected impact of the Ancillary Services dispatch instruction(s) over the time period within the Trading Interval for which such Ancillary Services dispatch instruction(s) applies.~~

~~**D 3.17.1 $L_{s/e}$ -MWh**~~

~~The Energy reduction by curtailable Load due to ISO dispatch of Supplemental Energy from such curtailable Load. This value will be calculated based on the projected impact of the Supplemental Energy dispatch instruction(s) over the time period within the Trading Interval for which such Supplemental Energy dispatch instruction(s) applies.~~

~~**D 3.18 I_s – MWh**~~

~~The total scheduled Energy import of Scheduling Coordinator j through Scheduling Point q in Settlement Period t as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.~~

~~**D 3.19 I_a – MWh**~~

~~The total actual Energy import of Scheduling Coordinator j through Scheduling Point q in BEEP Interval b in Settlement Period t. This is deemed to be equal to the total scheduled Energy import I_s.~~

~~**D 3.20 $I_{b,adj}$ – MWh**~~

~~The deviation in real time import ordered by the ISO for congestion management, overgeneration, etc. or a result of an import curtailment. This value will be calculated based on the projected impact of the Dispatch instruction(s) (or curtailment event) between the close of the Hour-Ahead Market and the end of the Trading Interval for which such Dispatch Instructions(s) (or curtailment event) applies.~~

~~D 3.21 $I_{a/s}$ – MWh~~

~~The Energy generated from Ancillary Service System Resources pursuant to Existing Contracts or Supplemental Energy from interties due to ISO's Dispatch instruction.~~

~~D 3.22 E_s – MWh~~

~~The total scheduled Energy export of Scheduling Coordinator j through Scheduling Point q in Settlement Period t as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.~~

~~**D 3.23 E_a – MWh**~~

~~The total actual Energy export of Scheduling Coordinator j through Scheduling Point q in BEEP Interval b of Settlement Period t. This is deemed to be equal to the total scheduled Energy export E_s.~~

~~**D 3.24 E_{adj} – MWh**~~

~~The deviation in Real Time export ordered by the ISO for Congestion Management, Overgeneration, etc. or as a result of an export curtailment. This value will be calculated based on the projected impact of the Dispatch Instruction(s) (or curtailment event) between the close of the Hour-Ahead Market and the end of the Trading Interval for which such Dispatch Instruction (or curtailment event) applies.~~

~~**D 3.25 P_{xt} – \$/MWh**~~

~~The Hourly Ex Post Price for Imbalance Energy for the relevant Trading Interval. This value is calculated as the weighted average of the 12 Five Minute Ex Post Prices in each Zone during each hour. The Five Minute Ex Post Price is equal to the bid price of the marginal resource accepted by the ISO for dispatch and deemed eligible to set the price during a five minute period.~~

~~**D 3.25.1 P_{eff} – \$**~~

~~Effective Price for Instructed Imbalance Energy for the relevant Settlement Period.~~

~~**D 3.26 $UFEC_j$ – \$**~~

~~The Unaccounted for Energy Charge for Scheduling Coordinator j is the cost representing the difference in Energy, for each UDC Service Area and Trading Interval, between the net Energy delivered into the UDC Service Area, adjusted for UDC Service Area Transmission Losses (calculated in accordance with ISO Tariff Section 7.4.3), and the total metered Demand within the UDC Service Area adjusted for distribution losses using Distribution System loss factors approved by the Local Regulatory Authority.~~

~~This difference (UFE) which is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical Load profile errors, and distribution loss deviations is multiplied by the Hourly Ex-Post Price.~~

~~**D 3.27 $E_{UFE\_UDC\_k}$ – MWh**~~

~~The Unaccounted for Energy (UFE) for utility service territory k.~~

~~**D 3.28 E_{UFE_z} – MWh**~~

~~The portion of Unaccounted for Energy (UFE) allocated to metering point z.~~

~~**D 3.29 $RRDC_j$**~~

~~The Replacement Reserve Capacity Dispatch Charge for Scheduling Coordinator j for Trading Interval t.~~

~~**D 3.30 RRC – $**~~

~~The Dispatched Replacement Reserve Capacity Cost which is to be allocated to Scheduling Coordinators in proportion to their contributions to Imbalance Energy requirements. The RRC is, in turn, calculated as the total cost of Replacement Reserve capacity in Trading Interval t (as determined in the Hour-Ahead and Day-Ahead Markets) less the Undispatched Replacement Reserve Capacity Cost. [Note: Both these costs are dealt with in the Ancillary Services payments in Appendix C]~~

~~**D 3.31**~~ ~~$\mathbf{G_k}$~~ ~~**– MWh**~~

~~The total metered Generation in BEEP Interval b of Settlement Period t in utility service territory k.~~

~~**D 3.32**~~ ~~$\mathbf{D_z}$~~ ~~**– MWh**~~

~~The Demand including Exports in BEEP Interval b of Settlement Period t at metered point z.~~

~~**D 3.33**~~ ~~$\mathbf{I_k}$~~ ~~**– MWh**~~

~~The total metered imports into utility service territory k in BEEP Interval b of Settlement Period t.~~

~~**D 3.34**~~ ~~$\mathbf{E_k}$~~ ~~**– MWh**~~

~~The total metered exports from utility service territory k in BEEP Interval b of Settlement Period t.~~

~~**D 3.35**~~ ~~$\mathbf{RTM_k}$~~ ~~**– MWh**~~

~~The Trading Interval t total of the real-time metering in utility service territory k in BEEP Interval b of Settlement Period t.~~

~~**D 3.36**~~ ~~$\mathbf{LPM_k}$~~ ~~**– MWh**~~

~~The calculated total of the Load Profile metering in utility service territory k per BEEP Interval b of Settlement Period t.~~

~~**D 3.37**~~ ~~$\mathbf{TL_k}$~~ ~~**– MWh**~~

~~The Transmission Losses per BEEP Interval b of Settlement Period t in utility service territory k.~~

~~**D 3.38 $IGDC_{ib}$ - $**~~

~~The total of instructed Generation deviation payments/charges for Scheduling Coordinator j in BEEP Interval b of Settlement Period t.~~

~~**D 3.39 $ILDC_{ib}$ - $**~~

~~The total of instructed Load deviation payments/charges for Scheduling Coordinator j in BEEP Interval b of Settlement Period t.~~

~~**D 3.40 $IIDC_{ib}$ - $**~~

~~The total of instructed import deviation payments/charges for Scheduling Coordinator j in BEEP Interval b of Settlement Period t.~~

~~D 3.41~~ **~~G_{ib} - MW~~**

~~Instructed Energy for Generating Unit i during BEEP Interval b.~~

~~D 3.42~~ **~~L_{ib} - MW~~**

~~Instructed Energy for Load i during BEEP Interval b.~~

~~D 3.43~~ **~~I_{iqb} – MW~~**

~~Instructed Energy for import q during BEEP Interval b~~

~~D 3.44~~ **~~P_b – \$/MWh~~**

~~The BEEP Incremental Ex Post Price for BEEP Interval b if the net instructed Energy for resources is positive, or the BEEP decremental Ex Post Price for BEEP Interval b if the net instructed Energy for resources is negative.~~

~~D 3.45~~ **~~HBI – Number~~**

~~The number of BEEP Intervals in Settlement Period t, currently set to 6.~~

~~D 3.46~~ **~~$ReplObligRatio_{jxt}$ – fraction~~**

$$ReplObligRatio_{jxt} = \frac{ReplOblig_{jxt}}{\sum_{j} ReplOblig_{jxt}}$$

~~where:~~

~~*$ReplOblig_{jxt}$* is the replacement reserve capacity obligation as defined in Appendix C Section 3.67.~~

~~D 3.47~~ **~~$G_{i, oblig}$~~**

~~The amount of Spinning Reserve, the amount of Non-Spinning Reserve, and the amount of Replacement Reserve that Generating Unit or System Resource i has been selected to supply to the ISO, as reflected in final Ancillary Services Schedules.~~

~~D 3.48~~ **~~$PMax_i$~~**

~~The maximum capability (in MW) at which Energy and Ancillary Services may be scheduled from the Generating Unit or System Resource i.~~

~~D 3.49~~ **~~$L_{i, oblig}$~~**

~~The amount of Non-Spinning Reserve and Replacement Reserve that dispatchable Load i has been selected to supply to the ISO as reflected in final Ancillary Services schedules for Settlement Period t.~~

APPENDIX E

CONGESTION REVENUE DISTRIBUTION

E 1 Purpose of Charge

Scheduling Coordinators will be charged for the use of Congested transmission or will receive payments for relieving the Congestion through the Settlement of Final Day-Ahead and Hour-Ahead Energy Schedules and through the Real-Time Imbalance Energy Market at the relevant Locational Marginal Prices. Scheduling Coordinators will also be charged for using Congested interties to import Ancillary Services.

Terms used in this Appendix:

Ancillary Service Congestion Charge is a charge to a Scheduling Coordinator for importing Spinning Reserve or Non-Spinning Reserve across a Congested intertie.. The charge for each service from each resource in each market (Day-Ahead Market or Hour Ahead Market) in each Settlement Period at each intertie equals the amount of import multiplied by the Ancillary Service Congestion Price at the intertie..

Ancillary Service Congestion Price is the Shadow Price of the transmission interface for a given market (Day-Ahead Market or Hour-Ahead Market) for a Settlement Period.

Shadow Price is the marginal price of reserving transmission capacity on the congested inter-tie to accommodate the associated Ancillary Services capacity.

E 2 Fundamental Formulae

E 2.1 ISO Credits and Debits to Transmission Owners and FTR Holders of Congestion Revenues

E 2.1.1 Day-Ahead Market

The ISO will pay or charge to FTR Holder *n* of a Point-To-Point FTR Obligation from node *i* to node *j* its share of the Congestion Revenue (which will be positive for payments or negative for charges) for Settlement Period t in the Day-Ahead Market as follows:

$$PayCR_{ntd}^{i \to j} = \left(\lambda_{jtd} - \lambda_{itd}\right) * L_{nt}^{i \to j}$$

The ISO will pay to FTR Holder *n* of a Point-To-Point FTR Option from node *i* to node *j* its share of the Congestion Revenue (only if positive) for Settlement Period t in the Day-Ahead Market as follows:

$$PayCR_{ntd}^{i \to j} = \max\left(0, \left(\lambda_{jtd} - \lambda_{itd}\right) * L_{nt}^{i \to j}\right)$$

To avoid double subscripts in notations, any Network Service Right can be described, without loss of generality, as the right for sending (p_1, p_2, …, p_s) % of one MW at nodes (1,2, …, *s*) and receiving (p_{s+1}, p_{s+2}, …, p_{s+r}) % of one MW at nodes (*s*+1, *s*+2, …, *s*+r). Using this notation, the ISO will pay or charge to FTR Holder *n* of Network Service Rights from node set {*i* } to node set {*j* } its share of the Congestion Revenue (which will be positive for payments or negative for charges) for Settlement Period t in the Day-Ahead Market as follows:

$$PayCR_{ntd}^{\{i\}\rightarrow\{j\}} = \left(\sum_{j=s+1}^{s+r} \lambda_{jtd}\, p_{jt} - \sum_{i=1}^{s} \lambda_{itd}\, p_{it} \right) * L_{nt}^{\{i\}\rightarrow\{j\}}$$

The Congestion Revenue that remains after deducting the payments to FTR holders will accumulate in the FTR Balancing Account.

E 2.1.2 Hour-Ahead Market

The Congestion Revenue collected through Settlement of Energy at Hour-Ahead LMPs and through the Ancillary Service Congestion Charge in the Hour-Ahead Market will accumulate in the FTR Balancing Account.

FTR holders are not entitled or obligated to any Congestion Revenue collected through Hour-Ahead Market.

E 3 Meaning of terms of formulae

E 3.1 λ_{jtd} **($/MWh)**

The reference Locational Marginal Price for node j for the relevant Settlement Period t in the Day-Ahead Market, as calculated by SCUC.

E 3.2 $PayCR_{ntd}^{i\rightarrow j}$ **($)**

The amount calculated by the ISO to be paid to or by the FTR Holder n of Point-To-Point FTR from node *i* to node *j* for the relevant Settlement Period t in the Day-Ahead Market.

E 3.3 $PayCR_{ntd}^{\{i\}\rightarrow\{j\}}$ **($)**

The amount calculated by the ISO to be paid to or by the FTR Holder n of Network Service Rights from node set {*i*} to node set {*j*} for the relevant Settlement Period t in the Day-Ahead Market.

E 3.4 $L_{nt}^{i\rightarrow j}$ **($)**

The amount FTR owned by the FTR Holder n of Point-To-Point FTR from node *i* to node *j* for the relevant Settlement Period t.

E 3.5 $L_{nt}^{\{i\}\rightarrow\{j\}}$ **($)**

The amount FTR owned by the FTR Holder n of Network Service Rights from node set {*i*} to node set {*j*} for the relevant Settlement Period t.

~~APPENDIX E~~

~~USAGE CHARGE COMPUTATION~~

~~E 1 Purpose of Charge~~

~~The Usage Charge is payable by Scheduling Coordinators who schedule Energy across Congested Inter-Zonal Interfaces pursuant to Section 7.2.5 of the ISO Tariff. Scheduling Coordinators who counter-schedule across Congested Inter-Zonal Interfaces are entitled to Usage Charge Payments. The right to schedule across a Congested Inter-Zonal Interface is determined through the ISO's Congestion Management procedures.~~

~~The following categories of Payments and Charges are covered in this Appendix E:~~

~~(a) Usage Charges payable by Scheduling Coordinators for Energy transfers scheduled across Congested Inter-Zonal Interfaces and which contribute to Congestion.~~

~~(b) Usage Charge rebates payable to Scheduling Coordinators for Energy transfers scheduled across Congested Inter-Zonal Interfaces and which contribute to relieving Congestion.~~

~~(c) Credits of net Usage Charge revenues to Participating TOs and FTR Holders.~~

~~(d) Debits of net Usage Charge revenues to Participating TOs and FTR Holders.~~

~~(e) Debits and rebates of Usage Charge to Scheduling Coordinators as set out in E 2.3.3.~~

~~E 2 Fundamental Formulae~~

~~E 2.1 ISO Usage Charges on Scheduling Coordinators~~

~~Each Scheduling Coordinator j whose Final Schedule includes the transfer of Energy scheduled across one or more Congested Inter-Zonal Interfaces shall (save to the extent that the transfer involves the use of transmission capacity represented by Existing Rights) pay, or be paid, Usage Charges in Trading Interval t calculated in accordance with the following formulae:~~

~~In the Day-Ahead Market:~~

$$UC_{jtd} = \sum_{x} NetZoneImp_{jtxd} * \lambda_{dxt}$$

~~In the Hour-Ahead Market:~~

$$UC_{jth} = \sum_{x} (NetZoneImp_{jtxh} - NetZoneImp_{jtxd}) * \lambda_{hxt}$$

~~E 2.2 Payments of Usage Charges to Scheduling Coordinators~~

~~Each Scheduling Coordinator j whose Final Schedule includes the transfer of Energy from one Zone to another in a direction opposite that~~

~~of Congestion shall (save to the extent that the transfer involves the use of transmission capacity represented by Existing Rights) receive a Usage Charge payment from the ISO calculated in accordance with the formulae described in Section E 2.1.~~

~~E 2.3 ISO Credits and Debits to Transmission Owners and FTR Holders of Usage Charge Revenues~~

~~E 2.3.1 Day-Ahead Market~~

~~The ISO will pay to the Participating TO n and FTR Holder n its share of the total net Usage Charge revenue for Trading Interval t in the Day-Ahead Market in accordance with the following formula:~~

$$\cancel{PayUC_{ntd} = \sum_{y} \mu_{ytd} * K_{yn} * L_{ytd}}$$

~~E 2.3.2 Hour-Ahead Market~~

~~The ISO will pay to the Participating TO n and FTR Holder n its share of the total net Usage Charge revenue for Trading Interval t in the Hour-Ahead Market in accordance with the following formula:~~

$$\cancel{PayUC_{nth} = \sum_{y} \mu_{yth} * K_{yn} * (L_{yth} - L_{ytd})}$$

~~Under normal operating conditions, (L_{yth} - L_{ytd}) is positive and Participating TOs and FTR Holders will receive a refund on the net Usage Charge for the relevant Trading Interval t in the Hour-Ahead Market.~~

~~E 2.3.3 Debits to Participating TOs and FTR Holders and Debits/Rebates to Scheduling Coordinators~~

~~If, after the close of the Day-Ahead Market, Participating TOs instruct the ISO to reduce interface limits based on operating conditions or an unscheduled transmission outage occurs and as a result of either of those events, Congestion is increased and Available Transfer Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the (L_{yth} - L_{ytd}) will be negative. In this case:~~

~~(a) Participating TOs and FTR Holders will be charged for the Usage Charge payments they received for the relevant Trading Interval t in the Day-Ahead Market with respect to the reduced interface limits;~~

~~(b) Any Scheduling Coordinator whose Schedule was adjusted for the relevant Trading Interval t in the Hour-Ahead Market due to the reduced interface limits will be credited with μ_{yth} for each MW of the adjustment; and~~

~~(c) Each Scheduling Coordinator will be charged an amount equal to it proportionate share, based on Schedules in the Day-Ahead Market in the direction of Congestion, of the difference between μ_{yth}(L_{yth} - L_{ytd}) and the total amount charged to Participating TOs and FTR Holders in accordance with item (a) above.~~

~~The ISO will issue a notice to Scheduling Coordinators of the operating hour, and extent, for which the derate will apply in the relevant Hour-Ahead Markets. The timing and form of such notices shall be set forth in ISO procedures.~~

~~E 3 Meaning of terms of formulae~~

~~E 3.1~~ $\cancel{UC_{jtd}}$ ~~($)~~

~~The Usage Charge payable by or to Scheduling Coordinator j for the relevant Trading Interval t in the Day-Ahead Market.~~

~~E 3.2~~ $\cancel{UC_{jth}}$ ~~- $~~

~~The Usage Charge payable by or to Scheduling Coordinator j for Trading Interval t in the Hour-Ahead Market.~~

~~E 3.3~~ $\cancel{NetZoneImp_{jtxd}}$ ~~(MWh)~~

~~The net Zonal import scheduled by Scheduling Coordinator j in Zone x for the relevant Trading Interval t in the Day-Ahead Market. For Zones internal to the ISO Control Area, net Zonal import equals scheduled Demand minus scheduled Generation plus transfers. For zones external to the ISO Control Area (i.e., for Scheduling Points), net zonal import equals scheduled imports (i.e., out of the ISO Control Area) minus scheduled exports (i.e., into the ISO Control Area).~~

~~E 3.4~~ $\cancel{NetZoneImp_{jtxh}}$ ~~(MWh)~~

~~The net Zonal import scheduled by the Scheduling Coordinator j in Zone x for the relevant Trading Interval t in the Hour-Ahead Market. For Zones internal to the ISO Control Area, net Zonal import equals scheduled Demand minus scheduled Generation plus transfers. For Zones external to the ISO Control Area (i.e., for Scheduling Points), net zonal import equals scheduled imports (i.e., out of the ISO Control Area) minus scheduled exports (i.e., into the ISO Control Area).~~

~~E 3.5~~ $\cancel{\lambda_{dxt}}$ ~~($/MWh)~~

~~The reference Zonal marginal price for Zone x for the relevant Trading Interval t in the Day-Ahead Market, as calculated by the ISO's Congestion Management computer optimization algorithm.~~

~~E 3.6~~ $\cancel{\lambda_{hxt}}$ ~~($/MWh)~~

~~The reference Zonal marginal price for Zone x for the relevant Trading Interval t in the Hour-Ahead Market, as calculated by the ISO's Congestion Management computer optimization algorithm.~~

~~E 3.7~~ $\cancel{PayUC_{ntd}}$ ~~($)~~

~~The amount calculated by the ISO to be paid to or by the Participating TO n (in respect of its Transmission Revenue Balancing Account) and FTR Holder n for the relevant Trading Interval t in the Day-Ahead Market.~~

~~**E 3.7.1**~~ ~~**$PayUC_{nth}$ ($)**~~

~~The amount calculated by the ISO to be paid to the Participating TO n (in respect of its Transmission Revenue Balancing Account) and FTR Holder n for the relevant Trading Interval t in the Hour-Ahead Market.~~

~~**E 3.8**~~ ~~**μ_{ytd} ($/MW)**~~

~~The Day-Ahead Congestion price (shadow price) at Inter-Zonal interface y for Trading Interval t. This price is calculated by the ISO's Congestion Management computer optimization algorithm.~~

~~**E 3.8.1**~~ ~~**μ_{yth} ($/MW)**~~

~~The Hour-Ahead Congestion price (shadow price) at Inter-Zonal Interface y for Trading Interval t. This price is calculated by the ISO's Congestion Management computer optimization algorithm.~~

~~**E 3.9**~~ ~~**K_{ytn} (%)**~~

~~The percentage of the Inter-Zonal Congestion revenue alocation for Participating TO n and FTR Holder n of the Congested Inter-Zonal interface y for the relevant Trading Interval t for both Day-Ahead and Hour-Ahead Markets.~~

~~**E 3.10**~~ ~~**L_{ytd} (MW)**~~

~~The total loading of Inter-Zonal Interface y for Trading Interval t in the Day-Ahead as calculated by the ISO's Congestion Management optimization algorithm.~~

~~**E 3.11**~~ ~~**L_{yth} (MW)**~~

~~The total loading of Inter-Zonal Interface y for Trading Interval t in the Hour-Ahead as calculated by the ISO's Congestion Management optimization algorithm.~~

APPENDIX F
WHEELING ACCESS CHARGES COMPUTATION

F 3.3 **Q_n** **(MW)**

The Available **Transmission**~~Transfer~~ Capacity, whether from transmission ownership or contractual entitlements, of each Participating TO n for each ISO Scheduling Point which has been placed within the ISO Controlled Grid. Available **Transmission**~~Transfer~~ Capacity does not include capacity associated with Existing Rights of a Participating TO as defined in Section 2.4.4 of the ISO Tariff.

APPENDIX G

VOLTAGE SUPPORT and BLACK START CHARGES COMPUTATION

G 1 Purpose of charge

G 1.1 Voltage Support (VS) and Black Start (BS) charges are the charges made by the ISO to recover costs it incurs under contracts entered into between the ISO and those entities offering to provide VS or BS. Each Scheduling Coordinator pays an allocated proportion of the VS&BS charge to the ISO so that the ISO recovers the total costs incurred.

G 1.2 All Generating Units are required by the ISO Tariff to provide reactive power by operating within a power factor range of 0.90 lag and 0.95 lead. Additional short term Voltage Support required by the ISO is referred to as supplemental reactive power. If the ISO requires the delivery of this supplemental reactive power by instructing a Generating Unit to operate outside its mandatory MVar range, the Scheduling Coordinator representing this Generating Unit will only receive compensation if it is necessary to reduce the MW output to achieve the MVar instructed output. Supplemental reactive power charges to Scheduling Coordinators are made on a ~~Trading~~Dispatch Interval basis. As of the ISO Operations Date the ISO will contract for long term Voltage Support Service with the Owner of Reliability Must-Run Units under Reliability Must-Run contracts.

G 1.3 The ISO will procure Black Start capability through contracts let on an annual basis. The quantities and locations of the Black Start capability will be determined by the ISO based on system analysis studies. Charges to Scheduling Coordinators for instructed Energy output from Black Start units are made on a ~~Trading~~Dispatch Interval basis.

G 2 Fundamental formulae

G 2.1 Payments to Scheduling Coordinators for providing Voltage Support

Payments to Scheduling Coordinators for additional Voltage Support service comprise:

G.2.1.1 Lost Opportunity Cost Payments (supplemental reactive power) to Scheduling Coordinators for Generating Units

When the ISO obtains additional Voltage Support by instructing a Generating Unit to operate outside its mandatory MVar range by reducing its MW output the ISO will select Generating Units based on their Supplemental Energy Bids ($/MWh). Subject to any locational requirements the ISO will select the Generating Unit with the highest decremental Supplemental Energy Bid to reduce MW output by such amount as is necessary to achieve the instructed MVar reactive energy production. Each ~~Trading~~Dispatch ~~-~~ Interval the ISO will pay Scheduling Coordinator j for that Generating Unit i in ~~Zone~~Location x, the lost opportunity cost ($) resulting from the reduction of MW output in ~~Trading~~Dispatch Interval t in accordance with the following formula:

$VSST_{xijt}= Max \{0,P_{xt} - Sup_{xdecit}\}*DEC_{xit}$

G 2.1.2 Long term contract payments to Scheduling Coordinators for Reliability Must-Run Units for Generating Units and other Voltage Support Equipment

The ISO will pay Scheduling Coordinator j for the provision of Voltage Support from its Reliability Must-Run Units located ~~in Zone~~at Location x in month m a sum ($VSLT_{xjm}$) consisting of:

(a) the total of the Ancillary Service Pre-empted Dispatch Payments if the ISO has decreased the output of the Reliability Must-Run Units for the provision of Voltage Support outside the power factor range of the Reliability Must-Run Unit in any ~~Trading~~Dispatch Interval in month m and/or

(b) (if applicable) the total payments for the provision of Voltage Support in month m requested by the ISO from the synchronous condensers of the Reliability Must-Run Units,

calculated in each case in accordance with the terms of the relevant Reliability Must-Run Contract. Data on these payments will not be generated by the ISO. Such data will be based on the invoices issued by the Owners of Reliability Must-Run Generating Units pursuant to their Reliability Must-Run Contracts and will be verified by the ISO.

G 2.2 Charges to Scheduling Coordinators for Voltage Support

G 2.2.1 User Rate

The user rate ($/MWh) for the lost opportunity cost for voltage support referred to in G2.1.1 in ~~Zone~~Load Zone ~~x~~ y for ~~Trading~~Dispatch Interval t will be calculated using the following formula:

$$VSSTRate_{yt} = \frac{\sum_{ijx} VSST_{xijt}}{\sum_{j} QChargeVS_{yjt}} \quad \cancel{VSSTRate_{xt} = \frac{\sum_{ij} VSST_{xijt}}{\sum_{j} QChargeVS_{xjt}}}$$

The user rate ($/MWh) for month m for long term voltage support referred to in G2.1.2 in ~~Zone~~Load Zone ~~x~~ y will be calculated using the following formula:

$$VSSTRate_{ym} = \frac{\sum_{jx} VSLT_{xjm}}{\sum_{jm} QChargeVS_{yjt}} \quad \cancel{VSSTRate_{xm} = \frac{\sum_{j} VSLT_{xjm}}{\sum_{jm} QChargeVS_{xjt}}}$$

G 2.2.2 Voltage Support Charges

The lost opportunity cost Voltage Support charge ($)payable to recover the sums under G2.1.1 for ~~Zone~~Load Zone ~~x~~ y for ~~Trading~~Dispatch Interval t for Scheduling Coordinator j will be calculated using the following formula:

$$VSSTCharge_{yjt} = VSSTRate_{ym} * QChargeVS_{yjt}$$

$$\cancel{VSSTCharge_{xjt} = VSSTRate_{xt} * QChargeVS_{xjt}}$$

The monthly long term voltage support charge ($) payable to recover sums under G2.1.2 for ~~Zone~~Load Zone ~~x~~ y for month m for Scheduling Coordinator j will be calculated using the following formula:

$$VSLTCharge_{yjm} = VSLTRate_{ym} * \sum_m QCharge_{yjt}$$

$$\cancel{VSLTCharge_{xjm} = VSLTRate_{xm} * \sum_m QChargeVS_{xjt}}$$

G 2.3 Payments to Participating Generators for Black Start

Payments to Participating Generators that provide Black Start Energy or capability shall be made in accordance with the agreements they have entered into with the ISO for the provision of Black Start services and shall be calculated as follows:

G 2.3.1 Black Start Energy Payments

Whenever a Black Start Generating Unit provides a Black Start in accordance with the ISO's instructions, the ISO will pay the Black Start Generator for that Unit for the Generating Unit's energy output and start-up costs. The ISO will pay Black Start Generator for Generating Unit i, the Black Start energy and start-up costs ($) in ~~Trading~~Dispatch Interval t in accordance with the following formula:

$$BSEn_{ijt} = (EnQBS_{ijt} * EnBid_{ijt}) + BSSUP_{ijt}$$

G 2.3.2 Black Start Energy Payments to Owners of Reliability Must-Run Units

Whenever a Reliability Must-Run Unit provides a Black Start in accordance with the ISO's instructions, the ISO will pay the Scheduling Coordinator of the Reliability Must-Run Unit the Generating Unit's Energy and start-up costs. The ISO will pay Scheduling Coordinator j for Reliability Must-Run Unit i the Black Start Energy and start-up costs ($) in ~~Trading~~Dispatch Interval t in accordance with the following formula:

$$BSEn_{ijt} = (EnQBS_{ijt} * EnBid_{ijt}) + (BSSUP_{ijt})$$

G 2.4 Charges to Scheduling Coordinators for Black Start

G 2.4.1 User Rate

The user rate ($/MWh) for Black Start Energy payments referred to in G2.3.1 and G2.3.2 for ~~Trading~~Dispatch Interval t will be calculated using the following formula:

$$BSRate_t = \frac{\sum_{ij} BSEn_{ijt}}{\sum_j QChargeBlackStart_{jt}}$$

G 2.4.2 Black Start Charges

The user charge ($/MWh) for Black Start Energy to recover the costs of payments under G2.3.1 and G2.3.2 for ~~Trading~~Dispatch Interval t for Scheduling Coordinator j will be calculated using the following formula:

$$BSCharge_{jt} = BSRate_t * QChargeBlackStart_{jt}$$

G 3 Meaning of Terms in the Formulae

G 3.1 $VSST_{xijt}$ ($)

The lost opportunity cost paid by the ISO to Scheduling Coordinator j for Generating Unit i ~~in Zone~~at Location x, resulting from the reduction of MW output in ~~Trading~~Dispatch Interval t.

G 3.2 P_{xt} ($/MWh)

The ~~Hourly~~ Location Marginal Price~~Ex Post~~ ~~price~~ for Imbalance Energy in ~~Trading~~Dispatch Interval t ~~in Zone~~at Location x.

G 3.3 Sup_{xdecit} ($/MWh)

The Supplemental Energy Bid ~~submitted by~~ for Scheduling Coordinator j for Generating Unit i ~~in~~at ~~Zone~~Locatione x in ~~Trading~~Dispatch Interval t, whose output is reduced by the ISO to provide additional short term Voltage Support.

G 3.4 Dec_{xit} (MW)

The reduction in MW by Scheduling Coordinator j for Generating Unit i ~~in Zone~~at Location x in ~~Trading~~Dispatch Interval t, in order to provide short term additional Voltage Support.

G 3.5 $VSLT_{xjm}$ ($)

The payment from the ISO to Scheduling Coordinator j for its Reliability Must-Run Units ~~in~~at ~~Zone~~Location x for Voltage Support in month m calculated in accordance with the relevant Reliability Must-Run Contract.

G 3.6 ~~$VSSTRate_{xt}$~~ $VSSTRate_{yt}$ ($/MWh)

The ~~Trading~~Dispatch Interval lost opportunity cost Voltage Support user rate charged by the ISO to Scheduling Coordinators for ~~Trading~~Dispatch Interval t for ~~Zone~~Load Zone ~~x~~y.

G 3.7 ~~$VSLTRate_{xm}$~~$VSLTRate_{ym}$ ($/MWh)

The monthly long term voltage support user rate charged by the ISO to Scheduling Coordinators for month m for ~~Zone~~Load Zone ~~x~~y.

G 3.8 $QChargeVS_{\cancel{x}yjt}$ (MWh)

The charging quantity for Voltage Support for Scheduling Coordinator j for ~~Trading~~Dispatch Interval t in ~~Zone~~Load Zone ~~x~~ y equal to the total metered Demand (including exports to neighboring Control Areas) for Scheduling Coordinator j in ~~Zone~~Load Zone ~~x~~ y for ~~Trading~~Dispatch Interval t.

G 3.9 ~~$VSSTCharge_{xjt}$~~$VSSTCharge_{yjt}$ ($)

The lost opportunity cost Voltage Support user charge for ~~Zone~~Load Zone ~~x~~ y for ~~Trading~~Dispatch Interval t for Scheduling Coordinator j.

G 3.10 **~~$VSLTCharge_{xjm}$~~$VSLTCharge_{yjm}$** **($)**

The long term charge for voltage support for month m for ~~Zone~~Load Zone ~~x~~ y for Scheduling Coordinator j.

G 3.11 **$BSEn_{ijt}$** **($)**

The ISO payment to Scheduling Coordinator j (or Black Start Generator j) for that Generating Unit i providing Black Start Energy in ~~Trading~~Dispatch Interval t.

G 3.12 **$EnQBS_{ijt}$** **(MWh)**

The energy output, instructed by the ISO, from the Black Start capability of Generating Unit i from Scheduling Coordinator j (or Participating Generator j) for ~~Trading~~Dispatch Interval t.

G 3.13 **$EnBid_{ijt}$** **($/MWh)**

The price for Energy output from the Black Start capability of Generating Unit i of Scheduling Coordinator j or (Black Start Generator j) for ~~Trading~~Dispatch Interval t calculated in accordance with the applicable Reliability Must-Run Contract or Interim Black Start Agreement.

G 3.14 **$BSSUP_{ijt}$** **($)**

The start-up payment for a Black Start successfully made by Generating Unit i of Scheduling Coordinator j (or Black Start Generator j) in ~~Trading~~Dispatch Interval t calculated in accordance with the applicable Reliability Must-Run Contract or Interim Black Start Agreement.

G 3.15 **$BSRate_t$** **($/MWh)**

The Black Start Energy Payment user rate charged by the ISO to Scheduling Coordinators for ~~Trading~~Dispatch Interval t.

G 3.16 **$QChargeBlackstart_{jt}$** **(MW)**

The charging quantity for Black Start for Scheduling Coordinator j for ~~Trading~~Dispatch Interval t equal to the total metered Demand (excluding exports to neighboring Control Areas) of Scheduling Coordinator j for ~~Trading~~Dispatch Interval t.

APPENDIX H. UNIT COMMITMENT COST

H.1 Calculation of Unrecovered Commitment Cost

The Unrecovered Commitment Costs will be calculated ex post for each committed unit for each Commitment Period as follows:

1) The Minimum Load Cost *MLC* will be calculated from the average proxy cost at minimum load $P_{\min}$, using the average heat rate function *AHR*(*P*) in Btu/kWh, the relevant gas price index *GPI* in $/Btu, and a $6/MWh adder for O&M costs:

$$MLC = (0.001\ AHR(P_{\min})\ GPI + 6)\ P_{\min} \tag{1}$$

2) For each Qualifying Hour *h*, the market revenue *MR* will be calculated for each Dispatch Interval *k* as the total of all Instructed Imbalance Energy and Uninstructed Imbalance Energy payments in that interval.

3) For each Qualifying Hour *h*, the operating cost *OC* will be calculated for each Dispatch Interval *k* as the proxy cost at the dispatched output P_k:

$$OC_{h,k} = (0.001\ AHR(P_k)\ GPI + 6)\ P_k \tag{2}$$

4) For each Qualifying Hour *h*, the market deficiency *MD* for recovering *MLC* will be calculated as follows:

$$MD_h = \min\left(0, \sum_{k=1}^{6} MR_{h,k} - MLC\right) \tag{3}$$

5) For each Qualifying Hour *h*, the market profit *MP* will be calculated as follows:

$$MP_h = \max\left(0, \sum_{k=1}^{6} \left(MR_{h,k} - OC_{h,k}\right)\right) \tag{4}$$

6) The Unrecovered Commitment Costs *UCC* for the Commitment Period will be calculated as the net of market deficiencies, market profits, and allocated startup costs *SC*, over all Qualifying Hours:

$$UCC = \min\left(0, \sum_h MP_h + \sum_h MD_h - \frac{m}{n} SC\right) \tag{5}$$

where *n* is the number of hours in an ISO Commitment Period and *m* is the number of Qualifying Hours within the Commitment Period.

Negative *UCC* indicates unrecovered cost that should be paid to eligible resources.

H.2 Allocation of Unrecovered Commitment Cost

For cost allocation purposes, the *UCC* for each committed resource for each eligible Commitment Period will be distributed evenly over all Qualifying Hours in that Commitment Period:

$$UCC_h = \frac{UCC}{m} \tag{6}$$

The total of all distributed *UCC* from all resources in a given hour would constitute the total Unrecovered Commitment Cost *TUCC* that needs to be allocated in that hour. Then, the *TUCC* will be allocated in two tiers as follows:

$$\begin{aligned} TUCC_1 &= TUCC \min\left(1, \frac{\max(0, D_M - D_S)}{\max(0, D_F - D_S)}\right) \\ TUCC_2 &= TUCC - TUCC_1 \end{aligned} \tag{7}$$

where D_F is the forecasted Demand plus scheduled exports, adjusted for energy schedules and bids expected at subsequent markets, D_S is the scheduled Demand plus scheduled exports, and D_M is the metered Demand. Tier 1, ($TUCC_1$), will be allocated to all SCs in proportion to their net negative demand deviations (demand under-scheduling). Tier 2, ($TUCC_2$) is due to ISO over-forecast and will be allocated to all SCs in proportion to their metered demand.

H.3 Phased Implementation

The proposed cost allocation scheme would work slightly differently in different markets and at different implementation phases of the Market Design 2002. Table 1 lists all the combinations. The short-term phase is 10/1/02–3/31/03 followed by the long-term phase on 4/1/03.

Table 1. *Phased implementation of cost allocation*

Market	Phase	Cost Allocation Basis	Tier 1 Allocation	Tier 2 Allocation
Day-Ahead Residual Unit Commitment	Short Term 10/02 – 4/03	Unrecovered commitment costs for units committed in DA RUC D_F: DA demand forecast plus DA scheduled exports D_S: final DA energy schedules	$TUCC_1$ allocated to all SCs in proportion to their net negative demand deviations from final DA Demand and export energy schedules	$TUCC_2$ allocated to all SCs in proportion to their metered demand
Hour-Ahead Residual Unit Commitment	Short Term 10/02 – 4/03	Unrecovered commitment costs for additional units committed in HA RUC D_F: HA demand forecast plus HA scheduled exports D_S: HA final energy schedules	$TUCC_1$ allocated to all SCs in proportion to their net negative deviations from final HA Demand and export energy schedules	$TUCC_2$ allocated to all SCs in proportion to their metered demand
Day-Ahead Energy Market	4/03 ff	Unrecovered commitment costs for units committed in DA Energy market	*TUCC* (no tiers) allocated to all SCs in proportion to their final DA scheduled demand in excess of their final DA scheduled supply, taking into account inter-SC energy trades that originate from self-committed resources	

Market	Phase	Cost Allocation Basis	Tier 1 Allocation	Tier 2 Allocation
Day-Ahead Residual Unit Commitment	4/03 ff	Unrecovered commitment costs for additional units committed in DA RUC D_F: DA demand forecast plus DA scheduled exports D_S: final DA energy schedules	$TUCC_1$ allocated to all SCs in proportion to their net negative deviations from final DA Demand and export energy schedules	$TUCC_2$ allocated to all SCs in proportion to their metered demand
Hour-Ahead Energy Market	4/03 ff	Unrecovered commitment costs for additional units committed in HA Energy market	*TUCC* (no tiers) allocated to all SCs in proportion to their final HA scheduled demand deviation in excess of their final HA scheduled supply deviation, taking into account HA inter-SC energy trade deviations that originate from self-committed resources	
Hour-Ahead Residual Unit Commitment	4/03 ff	Unrecovered commitment costs for additional units committed in HA RUC D_F: HA demand forecast plus HA scheduled exports D_S: final HA energy schedules	$TUCC_1$ allocated to all SCs in proportion to their net negative deviations from final HA Demand and energy schedules	$TUCC_2$ allocated to all SCs in proportion to their metered demand

METERING PROTOCOL

MP 2.3.4 Format for Data Submission

SCs shall submit Settlement Quality Meter Data to MDAS for the SC Metered Entities they represent using the Meter Data Exchange Format. Subject to any exemption granted by the ISO under MP 13, SCs must ensure that Settlement Quality Meter Data submitted to the ISO is in intervals of:

(a) 5 minutes for Loads and Generators providing Ancillary Services and/or Supplemental Energy; and

(b) 1 hour for other SC Metered Entities.

Each SC shall submit Settlement Quality Meter Data for all of the SC Metered Entities that it schedules aggregated by:

(a) the same Load aggregation that was used in scheduling ~~Demand Zone, Load group or bus~~ for Demand;

(b) the relevant unit for Generation; or

(c) the Scheduling Point for imports and exports.

The Settlement Quality Meter Data submitted by SCs may be in either kWh or MWh values.

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MP 13.5.2 Exemptions from Meter Standards

(a) General

The ISO has the authority under Section 10.5.2 of the ISO Tariff to exempt ISO Metered Entities from the requirement to comply with the meter standards referred to in the ISO Tariff and this Protocol.

(b) Specific Exemptions Available

i. Data Storage for Existing Meters

Revenue quality meters installed as at the ISO Operations Date are required to have 30 days data storage capacity (new revenue quality meters are required to have 60 days data storage capacity). Existing revenue quality meters that otherwise comply with the meter standards referred to in the ISO Tariff and this Protocol but which do not have 30 days data storage will be exempted from that requirement if there is alternative time stamped meter data storage of 30 days or more.

ii. Voltage Transformers

ISO Metered Entities will be exempt from the requirement to install Voltage Transformers (VT) at 500 kV and higher voltage levels provided that those ISO

Metered Entities install Capacity Coupled Voltage Transformers (CCVT) that meet the metering standards referred to in the ISO Tariff and this Protocol. The ISO Metered Entity must establish a testing program to ensure that the CCVT remains within the ISO's accuracy requirements. A copy of such test program must be supplied to the ISO and the ISO may require amendments and/or additions to that program that it reasonably believes are necessary to ensure the accuracy of the CCVT.

iii. Loss Correction Factors

The ISO may grant an ISO Metered Entity an exemption from compliance with the metering standards referred to in this Protocol and the ISO Tariff if, in the ISO's sole discretion, applicable loss correction factors can be applied to existing meters without any materially adverse effect on the accuracy or security of the Meter Data obtained from such meters.

~~iv. 5 Minute Interval Data~~

~~Generators that are ISO Metered Entities and that provide Ancillary Services to the ISO will not be required to provide the ISO with 5 minute interval data until such time as specified by the ISO. Until such time as the ISO requires 5 minute interval data, these entities will be required to provide the ISO with hourly interval data.~~

v. Request for Direct Polling

SCs may request the ISO to grant an exemption from the requirement to provide Settlement Quality Meter Data to the ISO for SC Metered Entities they represent if those entities are Generators which have requested the ISO, and the ISO has agreed, to directly poll them for Meter Data. Such Generators will be treated as ISO Metered Entities and must comply with all of the requirements relating to ISO Metered Entities in accordance with this Protocol and the ISO Tariff. The SC representing such Generators will be required to apply the relevant distribution loss factors to that Generator's Meter Data (the SC may obtain that Meter Data from the ISO).