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 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.

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.

~~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.

* * *

5.12.7.1.1.2.5 Qualifying Hour. A Qualifying Hour shall be an Hour in the ISO Commitment Period in which the ISO does not Dispatch the Generating Unit in accordance with its RMR Contract.

* * *

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.**

* * *

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.**

.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] **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.

~~**6.1.2.2.1** 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 **31.2.3.2.8**~~7.2 and 7.3~~.

* * *

7.2 [Not Used] ~~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.**

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

<u>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</u>

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 Dispatch Operating Point, for dispatched resources, or their final Hour-Ahead Schedule otherwise. The Dispatch 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 Instructions. 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**. ~~that Section 5.6.3 is not in effect and the ISO has not declared a staged System Emergency;~~

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. ~~Uninstructed Imbalance Energy resulting from declining intra-hour Instructions, however, 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 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. The 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;

gf) 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 Generating Units or aggregated groups of Generating Units 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;

m~~l~~) 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 equal to 50% 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 150% 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 the test for the purposes of validating unit performance;

__p__~~o~~) The Uninstructed Deviation Penalty will apply to __**Exceptional Dispatches**__~~Out of Market (OOM) transactions~~;

__q__~~p~~) Generating Units, __**Dispatchable Load**__ ~~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~~ or dispatchable Interconnection resource was physically incapable of delivering the expected Energy, provided that the Generating Unit, __**Dispatchable Load**__ ~~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~~ 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 __I__~~i~~nstruction within 72 hours of the operating hour in which the instruction is issued; and

__r__~~q~~) Operational adjustments associated __**with**__ interchange schedules making use of Existing Contract rights shall not be subject to the __**U**__~~u~~ninstructed __**D**__~~d~~eviation __**P**__~~p~~enalty.

* * * * *

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 Payment Options for ISO Dispatch Orders

With respect to all resources with no bids (either submitted or inserted by the ISO) in 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, 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 Congestion and there are no such RMR Units available, a resource may be called upon and paid under this Section to resolve the 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 as calculated in accordance with SABP Appendix D 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 for the relevant Dispatch Interval less verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction 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 Ancillary Service Marginal 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 Day-Ahead, Hour-Ahead and Real-Time Locational Marginal 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 Dispatch Instruction 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).

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 Iistructions 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~~ if 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]

~~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. [Not Used]

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~~**<u>Day-Ahead, Hour-Ahead,</u>** and real-time **<u>E</u>**~~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 Energy 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 Dispatch Instructions issued by the ISO.

3. The hourly total MWh quantity of the above short-term forward Energy and real-time incremental Imbalance Energy 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 Demand each hour. The calculation procedure is as follows:

1. The actual supply from Final Hour-Ahead 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 Supply and Demand) for each hour.

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 Energy limited resources, and estimated variable O&M costs of $4/MWh for combustion turbines and $2/MWh for other thermal units.

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 purchases capped at a price corresponding to a 12,000 MMBTU heat rate (plus the O&M adder)

6. The net Demand that must be met by these sources of Supply is calculated for each hour t as follows:

$$\begin{aligned}\text{Net Demand}_t =\ & \text{System Energy Demand}_t - \text{HA Net Imports}_t \\ & - \text{Residual ISO Supply}_t \\ & - \text{Estimated System Losses and Unaccounted for Energy}_t\end{aligned}$$

where:

$$\begin{aligned}\text{System Energy Demand}_t =\ & 1.07{*}\text{Actual ISO System Load}_t \\ & + \text{Upward Regulation Requirements}_t\end{aligned}$$

$$\text{HA Net Imports}_t = \text{SUMi (Final Hour Ahead Energy Schedule}_{i,t})$$

$$\begin{aligned}\text{Residual ISO Supply}_t = \text{SUMj (Max [Metered Output}_{j,t},\ & \\ \text{Final Hour Ahead Energy Schedule}_{j,t} & \\ + \text{ Upward Regulation Capacity Scheduled}_{j,t} & \\ + \text{Real Time Energy Dispatched}_{i,t} &\end{aligned}$$

+ 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~~ **Day-Ahead and Hour Ahead scheduled Demand** 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 rei<u>n</u>stitution 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

31.2.2.1 (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.

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 Source 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 Loadi 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:

$$UIE_{i,h,k} = GMM_{i,h,k} * ME_{i,h,k} - \int_{t=(k-1)T}^{kT} DOP_{i,h}(t)\,dt = GMM_{i,h,k} * ME_{i,h,k} - \left(SE_{i,h,k} + IIE_{i,h,k}\right) \quad (1)$$

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:

$$UIEC_{i,h,k} = -UIE_{i,h,k}\, LMP_{i,h,k} \quad (2)$$

where:

$\underline{UIEC_{i,h,k}}$ 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**

	Service imports. Congestion Revenue also includes the marginal cost of transmission losses.
Curtailable Demand	**Dispatchable Load that can only be reduced.** ~~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.~~
Customer Aggregation	**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.**
~~**Default GMM**~~	~~Pre calculated GMM based on historical Load and interchange levels.~~
Demand Bid	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 **Locational Marginal Price** ~~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 **Locational Marginal Price**~~Market Clearing Price~~.
Dispatch Interval	**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 Interval within the range of five (5) to thirty (30) minutes.**

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~~	~~*~~						~~Complete final dispatch schedules and transmission prices.~~
~~29~~		~~*~~						~~Complete final schedules and prices of each Ancillary Service.~~
~~30~~	~~1:00 PM~~	~~*~~						~~Complete final schedules.~~
~~31~~	~~1:00 PM~~	~~*~~						~~Inform all SCs their final dispatch schedules.~~
~~32~~		~~*~~						~~Inform all SCs their final AS schedules and prices.~~
~~33~~		~~*~~						~~Publish transmission prices if inter-zonal congestion exists.~~
~~34~~		~~*~~						~~Calculate and communicate with SC the specific SCs zonal prices if asked.~~
~~35~~				~~*~~				~~Publish PX prices.~~
~~36~~				~~*~~				~~Communicate the final generation and load schedules to PX participants.~~
~~37~~				~~*~~				~~Communicate the final Ancillary Service schedules to PX participants.~~
~~38~~		~~*~~						~~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~~		~~*~~						~~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** 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** 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:

$$P_i(\mathbf{x}) - P_i = 0 \qquad \text{for i = 1, 2, ..., N-1} \tag{1}$$

$$Q_i(\mathbf{x}) - Q_i = 0 \qquad \text{for i = 1, 2, ..., N}_d \tag{2}$$

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).

$$\sum_{i=1}^{N} P_i(\mathbf{x}) - P_{loss} = 0 \tag{3}$$

$$\sum_{i=1}^{N} Q_i(\mathbf{x}) - Q_{loss} = 0 \tag{4}$$

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:

$$P_i - P_i^{Max} \le 0 \qquad \text{for i = 1, 2, ..., N} \tag{5}$$

$$P_i^{Min} - P_i \le 0 \qquad \text{for i = 1, 2, ..., N} \tag{6}$$

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:

$$Q_i(\mathbf{x}) - Q_i^{Max} \le 0 \qquad \text{for i = N}_d\text{+1, N}_d\text{+2, ..., N}_d\text{+N}_g \tag{7}$$

$$Q_i^{Min} - Q_i(\mathbf{x}) \le 0 \qquad \text{for i = N}_d\text{+1, N}_d\text{+2, ..., N}_d\text{+N}_g \tag{8}$$

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,

$$F_k(\mathbf{x}) + \sum_{i \in T_k} (SP_i + NS_i + RU_i) - F_k^{Max} \leq 0 \tag{14}$$

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:

$$\frac{\partial L}{\partial[P_i(\mathbf{x}) - P_i]} = \lambda_i \tag{15}$$

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

$\lambda_N = \frac{\partial C_N}{\partial P_N}$ = 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., $\frac{\partial P_{loss}}{\partial P_i}$.

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:

$$\left[(\lambda_1 - \lambda_N) \quad (\lambda_2 - \lambda_N) \quad \ldots \quad (\lambda_{N-1} - \lambda_N) \quad \gamma_1 \quad \gamma_2 \quad \ldots \quad \gamma_{N_d}\right] = -\lambda_N \mathbf{L} - \left[\mu_1 \quad \mu_2 \quad \mu_3 \quad \ldots\right]\cdot \mathbf{S}$$

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:

$$\frac{\partial L}{\partial\left(R_j^{NS} - \sum_{i \in I_{NS} \cap Z_j} NS_i\right)} = \lambda_j^{NS} \qquad (27)$$

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:

$$\frac{\partial L}{\partial\left(R_j^{RD} - \sum_{i \in I_{RD} \cap Z_j} RD_i\right)} = \lambda_j^{RD} \qquad (28)$$

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:

$$\frac{\partial L}{\partial\left[F_k(\mathbf{x})+\sum_{i\in T_k}(SP_i+NS_i+RU_i)-F_k^{Max}\right]}=\mu_k \tag{29}$$

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, ..., 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 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:

$$
\begin{aligned}
CR &= -\sum_{i=1}^{N} \lambda_i P_i = -\sum_{i=1}^{N-1} \lambda_i P_i - \lambda_N P_N = -\sum_{i=1}^{N-1} \left(\lambda_N - \lambda_N L_i - \sum_k \mu_k S_{ki} \right) P_i - \lambda_N P_N \\
&= \sum_k \mu_k \sum_{i=1}^{N-1} (S_{ki} P_i) - \lambda_N \left[P_N + \sum_{i=1}^{N-1} (1 - L_i) P_i \right] = \sum_k \mu_k F_k^{Max} + \lambda_N \left[\sum_{i=1}^{N-1} L_i P_i - P_{loss} \right]
\end{aligned}
\tag{32}
$$

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

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~~**<u>**[NOT USED]**</u>

~~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 Iinstructions 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 Iinstructions 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