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which the UDC provides, pursuant to the rules and tariffs of the Local Regulatory Authority, for its bundled end-use customers.

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

2.2.5 Eligible Customers Represented by Scheduling Coordinators.

Each Scheduling Coordinator shall within ten (10) days of a request by the ISO provide the ISO with a list of the Eligible Customers which it represents at the date of the request.

2.2.6 Responsibilities of a Scheduling Coordinator.

Each Scheduling Coordinator shall be responsible for:

2.2.6.1 Obligation to Pay. Paying the ISO's charges in accordance with this ISO Tariff;

2.2.6.2 Submit Schedules. Submitting Schedules for Energy in the Day-Ahead Market and Hour-Ahead Market in relation to Market Participants for which it serves as Scheduling Coordinator;

2.2.6.3 Modifications in Demand and Supply. Coordinating and allocating modifications in scheduled Demand and exports and scheduled Generation and imports at the direction of the ISO in accordance with this ISO Tariff;

2.2.6.4 [Not Used]

2.2.6.5 Scheduling Deliveries. Including in its Schedules to be submitted to the ISO under this ISO Tariff, the Demand, Generation and Transmission Losses necessary to give effect to trades with other Scheduling Coordinators;

2.2.6.6 Tracking and Settling Trades. Tracking and settling all intermediate trades among the entities for which it serves as Scheduling Coordinator;

2.2.6.7 Ancillary Services. Providing Ancillary Services in accordance with Section 2.5;

2.2.6.8 Annual and Weekly Forecasts. Submitting to the ISO the forecasts as provided for in the Demand Forecast Protocol;

2.2.6.9 ISO Protocols. Complying with all ISO Protocols and ensuring compliance by each of the Market Participants which it represents with all applicable provisions of the ISO Protocols;

2.2.6.10 Interruptible Imports. Identifying any Interruptible Imports included in its Schedules; and

2.2.6.11 Participating Intermittent Resources. Submitting Schedules consistent with the technical standards for Participating Intermittent Resources adopted by the ISO and published on the ISO Home Page.

2.2.7 Operations of a Scheduling Coordinator.

2.2.7.1 Maintain Twenty-four (24) Hour Scheduling Centers. Each Scheduling Coordinator shall operate and maintain a twenty-four (24) hour, seven (7) days per week, scheduling center. Each Scheduling Coordinator shall designate a senior member of staff as its scheduling center manager who shall be responsible for operational communications with the ISO and who shall have sufficient authority to commit and bind the Scheduling Coordinator.

2.2.7.2 [Not Used]

2.2.7.3 Limitation on Trading. A Scheduling Coordinator, UDC or MSS that does not maintain an Approved Credit Rating, as defined with respect to either payment of the Grid Management Charge, or payment of other charges, shall maintain security in accordance with Section 2.2.3.2. For the avoidance of doubt, the ISO Security Amount is intended to cover the entity's outstanding and estimated liability for either (i) Grid Management Charge; (ii) Imbalance Energy, Ancillary Services, Grid Operations Charge, Wheeling Access Charge, High Voltage Access Charge, Transition Charge, Usage Charges, FERC Annual Charges. Each Scheduling Coordinator, UDC or MSS required to provide an ISO Security Amount under Section 2.2.3.2 shall notify the ISO of the initial ISO Security Amount (separated into amounts securing payment of the Grid Management Charge and amounts securing payments of other charges) that it wishes to provide at least fifteen (15) days in advance and shall ensure that the ISO has received such ISO Security Amount prior to the date the Scheduling Coordinator commences trading or the UDC or MSS commences receiving bills for the High Voltage

excessive by comparison with the likely cost of the amount of Energy scheduled by the Scheduling Coordinator.

2.2.8 The Scheduling Process.

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

2.2.8.1 [Not Used]

2.2.8.2 [Not Used]

2.2.8.3 [Not Used]

2.2.8.4 [Not Used]

2.2.9 [Not Used]

2.2.10 [Not Used]

2.2.10.1 [Not Used]

2.2.10.2 [Not Used]

2.2.10.3 [Not Used]

2.2.10.4 [Not Used]

2.2.10.5 [Not Used]

2.2.10.6 [Not Used]

2.2.10.7 [Not Used]

2.2.10.8 [Not Used]

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

Each Preferred Schedule submitted by a Scheduling Coordinator shall represent its preferred mix of Generation to meet its Demand and account for Transmission Losses and must include the name and identification number of each Eligible Customer for whom a Demand Bid is submitted, as well as:

2.2.11.1 [Not Used]

2.2.11.1.1 [Not Used]

2.2.11.1.2 [Not Used]

2.2.11.1.3 [Not Used]

2.2.11.1.4 [Not Used]

2.2.11.2 For Generation:

2.2.11.2.1 [Not Used]

2.2.11.2.2 [Not Used]

2.2.11.2.3 [Not Used]

2.2.11.2.4 [Not Used]

2.2.11.2.5 [Not Used]

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

2.2.11.3 [Not Used]

2.2.11.3.1 [Not Used]

2.2.11.3.2 [Not Used]

2.2.11.3.3 [Not Used]

2.2.11.3.4 [Not Used]

2.2.11.3.5 [Not Used]

2.2.11.3.6 [Not Used]

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

2.2.11.5 For Interruptible Imports: the quantity (in MWh) of Energy categorized as Interruptible Imports and whether the Scheduling Coordinator intends to self provide the Operating Reserve required by Section 2.5.3.2 to cover such Interruptible Imports or to purchase such Operating Reserve from the ISO.

2.2.12 Timing of Day-Ahead Scheduling.

2.2.12.1 The ISO may in its sole discretion waive the timing requirements of this Section 2.2 where necessary to preserve System Reliability. The ISO may also waive the

timing requirements of Section 2.2 where, because of error or delay, the ISO is unable to meet the timing requirements. Any such waiver shall be published on WEnet.

2.2.12.2 [Not Used]

2.2.12.2.1 [Not Used]

[Page Not Used]

2.2.12.2.2 [Not Used]

.

2.2.12.2.3 [Not Used]

2.2.12.2.3.1 [Not Used]

2.2.12.2.3.1.1 [Not Used]

2.2.12.2.3.2 [Not Used]

2.2.12.2.3.2.1 [Not Used]

2.2.12.2.3.3 [Not Used]

2.2.12.2.4 [Not Used]

[Page Not Used]

2.2.12.3 [Not Used]

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

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

2.2.12.6 [Not Used]

2.2.12.7 [Not Used]

2.2.12.8 [Not Used]

2.2.12.8.1 [Not Used]

2.2.12.8.2 [Not Used]

2.2.13 Timing of Hour-Ahead Scheduling.

2.2.13.1 Submission of Preferred Schedule. Each Scheduling Coordinator's Preferred Schedule for each Settlement Period during a Trading Day together with any additional or updated Energy Bids or Ancillary Services bids shall be submitted at least one hour prior to the commencement of that operating hour.

2.2.13.1.1 [Not Used]

2.2.13.1.2 [Not Used]

2.2.13.2 [Not Used]

2.2.13.2.1 [Not Used]

2.2.13.2.2 [Not Used]

2.2.13.2.3 [Not Used]

2.2.13.2.3.1 [Not Used]

2.2.13.2.3.2 [Not Used]

2.2.13.2.3.3 [Not Used]

2.2.13.3 Final Hour-Ahead Schedules. The ISO shall inform each Scheduling Coordinator of its responsibilities to provide Ancillary Services in accordance with Section 2.5.21. Not later than thirty (30) minutes before the commencement of each Settlement Period, the ISO shall provide each Scheduling Coordinator with the Final Schedule for that Settlement Period. Each Final Schedule shall contain the following information:

2.2.13.3.1 Generation.

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

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

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

2.2.13.3.1.4 Notification if the scheduled Generation was adjusted.

2.2.13.3.1.5 [Not Used]

2.2.13.3.2 Load.

2.2.13.3.2.1 For each Load where a Demand Bid has been submitted, the Load Aggregation Point;

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

2.2.13.3.2.3 Notification of Adjustment. Notification if the scheduled Demand was adjusted.

2.2.13.4 [Not Used]

2.2.14 Communications.

2.2.14.1 Communications between the ISO and Scheduling Coordinators shall take place via direct computer link to a dedicated terminal at the Scheduling Coordinator's scheduling center. The ISO will establish the back-up communication procedures as part of the ISO Protocols.

2.2.14.2 Any Generation or Demand that is available for Dispatch must be capable of responding to ISO Dispatch instructions through a direct computer link or other means in accordance with the ISO Protocol on Dispatch.

2.2.15 Verification of Information.

The ISO shall be entitled to take all reasonable measures to verify that Scheduling Coordinators meet the technical and financial criteria set forth in Section 2.2.3 hereof and the accuracy of information submitted to the ISO pursuant to Section 2.2.11.

2.2.16 Relationship Between ISO and Participating Loads

The ISO shall only accept bids for Supplemental Energy or Ancillary Services, or Schedules for self-provision of Ancillary Services, from Loads if such Loads are Participating Loads which meet standards adopted by the ISO and published on the ISO Home Page. The ISO shall not schedule Energy or Ancillary Services from a Participating Load other than through a Scheduling Coordinator.

2.2.17 Relationship Between ISO and Eligible Intermittent Resources and Between the ISO and Participating Intermittent Resources

The ISO shall not schedule Energy from an Eligible Intermittent Resource other than through a Scheduling Coordinator. Settlement with Participating Intermittent Resources that meet the scheduling obligations established in the technical standards for Participating Intermittent Resources adopted by the ISO and published on the ISO Home Page shall be as provided in this ISO Tariff. No adjustment bids or Supplemental Energy bids may be submitted on behalf of Participating Intermittent Resources. Any Eligible Intermittent Resource that is not a Participating Intermittent Resource, or any Participating Intermittent Resource for which Adjustment Bids or Supplemental Energy bids are submitted, or that fails to meet the scheduling obligations established in the technical standards for Participating Intermittent Resources adopted by the ISO and published on the ISO Home Page, shall be scheduled and settled as a Generating Unit for the associated Settlement Periods.

2.3 System Operations under Normal and Emergency Operating Conditions.

2.3.1 ISO Control Center Operations.

2.3.1.1 ISO Control Center.

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

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

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

(a) direct the physical operation by the Participating TOs of transmission facilities under the Operational Control of the ISO, including (without limitation) circuit

breakers, switches, voltage control equipment, protective relays, metering, and Load Shedding equipment;

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

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

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

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

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

(g) procure Supplemental Energy.

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

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

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

2.3.1.2 Market Participant Responsibilities.

2.3.1.2.1 Comply with Operating Orders Issued. With respect to this Section 2.3.1.2, all Market Participants within the ISO Control Area and all System Resources shall comply fully and promptly with the ISO's operating orders, unless such operation would impair public health or safety. In this regard, Final Hour-Ahead Schedules for Energy for Generating Units, System Resources, System Units and Dispatchable Loads are deemed to be operating orders. As such these Schedules are binding obligations and must be fulfilled unless otherwise directed by the ISO. Any Hour-Ahead Ancillary Services Schedule or Supplementary Energy Bid is a binding obligation, and a resource so scheduled or bid cannot be made unavailable or otherwise fail to respond to ISO operating orders except for conditions beyond the control of the resource owner. Any Day-Ahead commitment of a resource, either self-scheduled or committed in an ISO Energy market or through an ISO Residual Unit Commitment Process is a binding obligation, and such resource cannot be de-committed or otherwise made unavailable except for conditions beyond the control of the resource owner or as approved by the ISO. For this purpose ISO operating orders to shed Load shall not be considered as an impairment to public health or safety.

2.3.1.2.2 Implementation of Instructions. All Market Participants shall respond to ISO instructions with no more delay than specified in the response times set out in the ISO Protocols.

2.3.1.3 Operating Reliability Criteria.

2.3.1.3.1 The ISO shall exercise Operational Control over the ISO Controlled Grid to meet planning and Operating Reserve criteria no less stringent than those established by WSCC and NERC as those standards may be modified from time to time, and Local Reliability Criteria that are in existence on the ISO Operations Date and have been submitted to the ISO by each Participating TO pursuant to Section 2.2.1(v) of the TCA. All Market Participants and the ISO shall comply with the ISO reliability criteria, standards, and procedures.

2.3.1.3.2 The ISO may establish planning and Operating Reserve criteria more stringent than those established by WSCC and NERC or revise the Local Reliability Criteria subject to and in accordance with the provisions of the TCA.

2.3.2 Management of System Emergencies.

2.3.2.1 Declaration of System Emergencies. The ISO shall, when it considers that conditions giving rise to a System Emergency exist, declare the existence of such System

Emergency. A declaration by the ISO of a System Emergency shall be binding on all Market Participants until the ISO announces that the System Emergency no longer exists.

2.3.2.2 Emergency Procedures. In the event of a System Emergency, the ISO shall take such action as it considers necessary to preserve or restore stable operation of the ISO Controlled Grid. The ISO shall act in accordance with Good Utility Practice to preserve or restore reliable, safe and efficient service as quickly as reasonably practicable. The ISO shall keep system operators in adjacent Control Areas informed as to the nature and extent of the System Emergency in accordance with WSCC procedures and, where practicable, shall additionally keep the Market Participants within the Control Area informed.

2.3.2.3 Intervention in Market Operations. The ISO may intervene in the operation of the Day-Ahead Market, the Hour-Ahead Market or the Real Time Market and set the Administrative Price, if the ISO determines that such intervention is necessary in order to contain or correct a System Emergency as follows.

2.3.2.3.1 The ISO will not intervene in the operation of the Day-Ahead Market unless there has been a total or major collapse of the ISO Controlled Grid and the ISO is in the process of restoring it.

2.3.2.3.2 Before any such intervention the ISO must: (a) dispatch all scheduled Generation and all other Generation offered or available to it regardless of price (including all Energy bids and Ancillary Services); (b) dispatch all interruptible loads made available by UDCs to the ISO in accordance with the relevant agreements with UDCs; (c) dispatch or curtail all price-responsive Demand that has been bid into any of the markets and exercise its rights under all load curtailment contracts available to it; (d) exercise Load

Shedding to curtail Demand on an involuntary basis to the extent that the ISO considers necessary.

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

2.3.2.3.4 The intervention will cease as soon as the ISO has restored all Demand that was curtailed on an involuntary basis under Section 2.3.2.3.2(d).

2.3.2.4 Emergency Guidelines. The ISO shall issue protocols for all Market Participants to follow during a System Emergency. These guidelines shall be consistent with the specific obligations of Scheduling Coordinators and Market Participants referenced in Section 2.3.2.7 below.

2.3.2.5 Periodic Tests of Emergency Procedures. The ISO shall develop and administer periodic unannounced tests of System Emergency procedures set out in the ISO Protocols. Such tests shall be designed to ensure that the ISO Market Participants are capable of promptly and efficiently responding to imminent or actual System Emergencies.

2.3.2.6 Prioritization Schedule for Shedding and Restoring Load. Prior to the ISO Operations Date, and annually thereafter, the ISO shall, in consultation with Market Participants and subject to the provisions of Section 2.1.3, develop a prioritization schedule for Load Shedding should a System Emergency require such action. The prioritization schedule shall also establish a sequence for the restoration of Load in the event that multiple Scheduling Coordinators or Market Participants are affected by service interruptions and Load must be restored in blocks.

2.3.2.7 Further Obligations Relating to System Emergencies. The ISO and Participating TOs shall comply with their obligations in Section 9 of the TCA. The ISO and UDCs shall comply with their obligations in Section 4 of this ISO Tariff. The ISO and Generators shall comply with their obligations in Section 5 of this ISO Tariff.

2.3.2.8 Use of Load Curtailment Programs.

2.3.2.8.1 Use of UDC's Existing Load Curtailment Programs. As an additional resource for managing System Emergencies, the ISO will, subject to Section 2.1.3, notify the UDCs when the conditions to implement their Load curtailment programs have been met in accordance with their terms. Each UDC shall by not later than October 1 of each year advise the ISO of the capabilities of its Load curtailment programs for the forthcoming year, and the conditions under which those capabilities may be exercised and shall give the ISO as much notice as reasonably practicable of any change to such programs.

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

2.3.3.5.2 Where the ISO Outage Coordination Office reasonably determines that the requested Maintenance Outage or the requested change to an Approved Maintenance Outage, when evaluated together with existing Approved Maintenance Outages, is not likely to have a detrimental effect on the efficient use and reliable operation of the ISO Controlled Grid, the ISO shall authorize the Maintenance Outage or change to the Approved Maintenance Outage, and shall so notify the requesting Operator and other entities who may be directly affected.

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

2.3.3.5.4 In the event an Operator of facilities forming part of the ISO Controlled Grid cancels an Approved Maintenance Outage after 5:00 a.m. of the day prior to the day upon which the Outage is scheduled to commence and the ISO determines that the change was not required to preserve System Reliability, the ISO may disregard the availability of the affected facilities in determining the availability of transmission capacity in the Day-Ahead Market, provided, however, that the ISO will, as promptly as practicable, notify Market

2.3.3.9.3 The ISO Control Center shall coordinate any operational changes necessary to accommodate a Forced Outage and Market Participants shall comply with the ISO's instructions given for that purpose.

2.3.3.9.4 All Forced Outages shall be communicated by the ISO Control Center to Operators likely to be affected by the Outage using the same procedures adopted for Maintenance Outage coordination procedures.

2.3.3.9.5 Within forty-eight (48) hours of the commencement of a Forced Outage, the Operator shall provide to the ISO an explanation of the Forced Outage, including a description of the equipment failure or other cause and a description of all remedial actions taken by the Operator. Upon request of the ISO, Operators, and where applicable, Eligible Customers, Scheduling Coordinators, UDCs and MSSs promptly shall provide information requested by the ISO to enable the ISO to review the explanation submitted by the Operator and to prepare reports on Forced Outages. If the ISO determines that any Forced Outage may have been the result of gaming or other questionable behavior by the Operator, the ISO shall submit a report describing the basis for its determination to the FERC. The ISO shall consider the following factors when evaluating the Forced Outage to determine if the Forced Outage was the result of gaming or other questionable behavior by the operator: 1) if the Forced Outage coincided with certain market conditions such that the Forced Outage may have influenced market prices or the cost of payments associated with Exceptional Dispatches, or other Real Time Market Dispatches; 2) if the Forced Outage coincided with a change in the bids submitted for any units or resources controlled by the Operator or the Operator's Scheduling Coordinator; 3) if the ISO had recently rejected a request for an outage for, or to shut down, the Generating

Unit experiencing the Forced Outage; 4) if the timing or content of the notice of the Forced Outage provided to the ISO was inconsistent with subsequent reports of or the actual cause of the outage; 5) if the Forced Outage or the duration of the Forced Outage was inconsistent with the history or past performance of that Generating Unit or similar Generating Units; 6) if the Forced Outage created or exacerbated congestion; 7) if the Forced Outage was extended with little or no notice; 8) if the Operator had other alternatives to resolve the problems leading to the Forced Outage; 9) if the Operator took reasonable action to minimize the duration of the Forced Outage; or 10) if the Operator failed to provide the ISO an explanation of the Forced Outage within forty-eight (48) hours or failed to provide any additional information or access to the generating facility requested by the ISO within a reasonable time.

2.3.3.10 Other Control Areas. The ISO Outage Coordination Office shall make all reasonable efforts to coordinate Outages involving other Control Areas or affecting an intertie, import or export capability not under the Operational Control of the ISO to the extent that they may affect the reliability of the ISO Controlled Grid.

2.3.3.11 Records. The ISO and all Operators shall develop procedures to keep a record of approved Maintenance Outages as they are implemented and to report the completion of approved Maintenance Outages.

2.3.4 Management of Overgeneration Conditions.

The ISO shall use default Energy Bids as set forth in Section 31.2.3.1.4.2 in SCUC to adjust Schedules to manage Overgeneration in the Day-Ahead and Hour-Ahead Energy Markets. Overgeneration in real time will be mitigated by the ISO as follows; provided that the ISO operator will have the discretion, if necessary to avoid a system emergency, to eliminate one or more of the following steps.

2.3.4.2 To the extent that there are insufficient decremental Energy bids available for the operating hour to fully mitigate the Overgeneration condition, the ISO will notify Scheduling Coordinators of the projected amount of Overgeneration to be mitigated in that hour.

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

2.3.4.4 To the extent that the steps described in Sections 2.3.4.1 through 2.3.4.3 fail to mitigate Overgeneration, the ISO will instruct Scheduling Coordinators to reduce either Generation, or imports, or both. The amount of the reduction for each Scheduling Coordinator will be calculated pro rata based on the product of the total required reduction in Generation and imports (or increase in exports) and the ratio of its Demand to the total Demand in the ISO Control Area.

2.3.4.5 To the extent that the above steps fail to fully mitigate the Overgeneration, the ISO will issue mandatory Dispatch instructions for specific reductions in Generating Unit output and external imports and all relevant Scheduling Coordinators shall be obligated to comply with such Dispatch instructions.

2.3.4.6 Any costs incurred by the ISO in implementing Section 2.3.4.3 shall be reimbursed to the ISO by Scheduling Coordinators based upon the extent to which they supplied Energy, in metered amounts, greater than the Generation and imports scheduled in their Final Schedules and consumed Energy, in metered amounts, less than the Demand scheduled in their Final Schedules, as a proportion of the total amount of such excess or shortfall among all Scheduling Coordinators.

2.3.5 Assurance of Adequate Generation and Transmission to meet Applicable Operating and Planning Reserve.

2.3.5.1 Generation Planning Reserve Criteria. Generation planning reserve criteria shall be met as follows:

2.3.5.1.1 On an annual basis, the ISO shall prepare a forecast of weekly Generation capacity and weekly peak Demand on the ISO Controlled Grid. This forecast shall cover a period of twelve months and be posted on the WEnet and the ISO may make the forecast available in other forms at the ISO's option.

2.3.5.1.2 If the forecast shows that the applicable WSCC/NERC Reliability Criteria can be met during peak Load periods, then the ISO shall take no further action.

2.3.5.1.3 If the forecast shows that the applicable WSCC/NERC Reliability Criteria cannot be met during peak Load periods, then the ISO shall facilitate the development of market mechanisms to bring the ISO Controlled Grid during peak periods into compliance with the Applicable Reliability Criteria (or such more stringent criteria as the ISO may impose pursuant to Section 2.3.1.3.2). The ISO shall solicit bids for Reserves in the form of Ancillary Services, short-term Generation supply contracts of up to one (1) year with Generators, and Load curtailment contracts giving the ISO the right to reduce the Loads of those parties that win the contracts when there is insufficient Generation capacity to satisfy those Loads in addition to all other Loads. The curtailment contracts shall provide that the ISO's curtailment rights can only be exercised after all available Generation capacity has been fully utilized unless the exercise of such rights would allow the ISO to satisfy the Applicable Reliability Criteria at lower cost, and the curtailment rights shall not be exercised to stabilize or otherwise influence prices for power in the Energy markets.

2.3.5.1.4 If Reserves, short-term Generation supply contracts or curtailment contracts are required to meet Applicable Reliability Criteria, the ISO shall select the bids that permit the satisfaction of those Applicable Reliability Criteria at the lowest cost.

2.3.5.1.5 Notwithstanding the foregoing, if the ISO concludes that it may be unable to comply with the Applicable Reliability Criteria, the ISO shall, acting in accordance with Good Utility Practice, take such steps as it considers to be necessary to ensure compliance, including the negotiation of contracts through processes other than competitive solicitations.

2.3.5.1.6 The ISO may, in addition to the required annual forecast, publish a forecast of the peak loads and Generation resources for two or more additional years. This forecast would be for information purposes to allow Market Participants to take appropriate steps to satisfy the Applicable Reliability Criteria, and would not be used by the ISO to determine whether additional resources are necessary.

2.3.5.1.7 In fulfilling its requirement to ensure that the applicable Generation planning reserve criteria are satisfied, the ISO shall rely to the maximum extent possible on market forces.

2.3.5.1.8 Except where and to the extent that such costs are recovered from Scheduling Coordinators pursuant to Section 2.5, and except as provided in Section 2.3.5.1.9, all costs incurred by the ISO in any hour pursuant to any contract entered into under this Section 2.3.5.1 shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordiantor's metered hourly Demand (including exports) bears to the total metered hourly Demand (including exports) served in that hour.

2.3.5.1.9 Costs incurred by the ISO pursuant to any contract entered into under this Section 2.3.5.1 for resources to meet any portion of the anticipated difference between

parties cannot agree to the operating instructions submitted by the parties, until the dispute is resolved, and unless the Existing Contract specifies otherwise, the ISO shall implement the operating instructions of the first Participating TO for which the Existing Contract is an Encumbrance.

2.4.4.4.2 The ISO's scheduling protocols will accommodate Existing Rights, so that the holders of Existing Rights will receive the same priorities (in scheduling, curtailment, assignment and other aspects of transmission system usage) to which they are entitled under their Existing Contracts.

2.4.4.4.3 Scheduling deadlines and operational procedures associated with Existing Rights will be honored by the ISO.

2.4.4.4.4 All contractual provisions that have been communicated to the ISO in writing in accordance with Section 2.4.4.4.1 by the parties to the Existing Contracts, shall be honored by the ISO and the parties to the Existing Contracts and shall be implemented in accordance with the terms and conditions of the relevant Existing Contracts so notified.

2.4.4.4.4.1 The holders of Existing Rights shall not be charged the Locational Marginal Price at the Sink or paid the Location Marginal Price at the Source for their Final Day-Ahead or Final Hour-Ahead Energy Schedules associated with Existing Rights.

2.4.4.4.4.2 Other than any existing rights to such revenues under the Existing Contracts, the holders of Existing Rights will not be entitled to an allocation of revenues from Wheeling Out or Wheeling Through services on the ISO Controlled Grid, related to those rights.

2.4.4.4.4.3 The holders of Existing Rights shall continue to pay the providers of the Existing Rights at the rates provided in the associated Existing Contracts, as they may change from time to time under the terms of the Existing Contracts.

2.5 Ancillary Services.

2.5.1 Scope.

The ISO shall be responsible for ensuring that there are sufficient Ancillary Services available to maintain the reliability of the ISO Controlled Grid consistent with WSCC and NERC criteria. The ISO's Ancillary Services requirements may be self provided by Scheduling Coordinators. Those Ancillary Services which the ISO requires to be available but which are not being self provided will be competitively procured by the ISO from Scheduling Coordinators in the Day-Ahead Market, Hour-Ahead Market and in real time or by longer term contracts. The ISO will manage both ISO procured and self provided Ancillary Services as part of the real time dispatch. The ISO will calculate payments for Ancillary Services to Scheduling Coordinators and charge the cost to Scheduling Coordinators.

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

2.5.2 Ancillary Services Standards.

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

2.5.2.1 Determination of Ancillary Service Standards. The ISO shall set the required standard for each Ancillary Service necessary to maintain the reliable operation of the ISO

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

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

2.5.3 Quantities of Ancillary Services Required.

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

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

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

2.5.3.3 [Not Used]

2.5.3.4 Voltage Support.

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

All Participating Generators shall maintain the ISO specified voltage schedule at the transmission interconnection points to the extent possible while operating within the power factor range specified in their interconnection agreements or, for Regulatory Must-Take Generation, Regulatory Must-Run Generation and Reliability Must-Run Generation consistent with existing obligations. For Generating Units, that do not operate under one of these agreements, the minimum power factor range will be within a band of 0.90 lag

(producing VARs) and 0.95 lead (absorbing VARs) power factors. Participating Generators with Generating Units existing at the ISO Operations Date that are unable to meet this operating power factor requirement may apply to the ISO for an exemption. Prior to granting such an exemption, the ISO shall require the Participating TO or UDC to whose system the relevant Generating Units are interconnected to notify it of the existing contractual requirements for voltage support established prior to the ISO Operations Date for such Generating Units. Such requirements may be contained in CPUC Electric Rule 21 or the Interconnection Agreement with the Participating TO or UDC. The ISO shall not grant any exemption under this Section from such existing contractual requirements. The ISO shall be entitled to instruct Participating Generators to operate their Generating Units at specified points within their power factor ranges. Generators shall receive no compensation for operating within these specified ranges.

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

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

The power factor for both the Generating Units and Loads shall be measured at the interconnection point with the ISO Controlled Grid. The ISO will develop and will be authorized to levy penalties against Participating Generators, UDCs or Loads whose

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

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

(ii) ISO Controlled Grid restoration times; and

(iii) load restoration times.

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

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

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

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

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

(d) Additional Regulation and Spinning Reserve capacity can be used to satisfy requirements for Non-Spinning Reserve;

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

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

2.5.4 Locational Quantities of Ancillary Services.

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

2.5.4.1 Black Start Units.

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

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

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

2.5.5 Time-frame For Contracting for Ancillary Services.

The ISO shall procure on a daily and hourly basis, each day, Regulation, Spinning, and Non-Spinning Reserves. The ISO shall procure reserves on a

longer term basis pursuant to Section 2.3.5.1.3 if necessary to meet reliability criteria. The ISO Governing Board must approve all long term reserve contracts. The ISO shall contract for Voltage Support annually (or for such other period as the ISO may determine is economically advantageous) and on a daily or hourly basis as required to maintain System Reliability. The ISO shall contract annually (or for such other period as the ISO may determine is economically advantageous) for Black Start Generation.

2.5.6 Technical Requirements for Providing Ancillary Services.

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

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

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

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

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

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

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

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

The ISO will specify the operating characteristics necessary to provide each Ancillary Service in the Ancillary Services Requirements Protocol.

2.5.6.2 Communication Equipment. Unless otherwise authorized by the ISO, all Scheduling Coordinators wishing to submit an Ancillary Service schedule or bid must have the capability to submit and receive information by direct computer link. In addition, they must be capable of receiving Dispatch instructions electronically and they must provide the ISO with a telephone number, or fax number through which Dispatch instructions for each Generating Unit, System Unit, Load and System Resource may be given if necessary. The ISO will determine which method of communication is appropriate; provided that the

(d) meter capability in regard to AGC response; and

(e) any other aspect of metering infrastructure required by the ISO under this ISO Tariff.

2.5.6.4 Additional Requirements for Black Start Units.

A Participating Generator who wishes to offer Black Start must ensure that the requirements set out in Appendix D to this ISO Tariff are met in relation to the Generating Units from which Black Start will be offered.

2.5.7 Methodology For Procurement of Ancillary Services Upon Commencement of ISO Operations.

2.5.7.1 [NOT USED]

2.5.7.2 Accounting for Congestion in Ancillary Service Bid Evaluation.

The ISO will account for Congestion in its Ancillary Service bid evaluations as set forth in Section 31.2.3.1.4.4.

2.5.7.3 Market Based Prices.

Public utilities under the FPA must submit bids for Ancillary Services capped at FERC authorized cost-based rates unless and until FERC authorizes different pricing. Public utilities under the FPA shall seek FERC Ancillary Services rate approval on bases consistent with the ISO time-frame for contracting for each Ancillary Service (hourly rate for some Ancillary Services, annual rate or otherwise for other Ancillary Services) so that cost-based bids and market based bids for each service shall be on comparable terms. All

Section 31.1. This information shall be provided at the same time as the ISO provides general system information to all Scheduling Coordinators wishing to schedule power on the ISO Controlled Grid.

2.5.10 Time Frame for Submitting And Evaluating Bids.

2.5.10.1 Day-Ahead Auction. Bids for the ISO's Day-Ahead Regulation, Spinning Reserve and Non-Spinning Reserve service market must be received by 10:00 am on the day prior to the Trading Day. The bids shall include information for each Settlement Period of the Trading Day. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO.

2.5.10.2 Hour-Ahead Auction. Bids for the ISO's Hour-Ahead Regulation, Spinning Reserve and Non-Spinning Reserve service market for each Settlement Period must be received at least one hour prior to the commencement of that Settlement Period. The bids shall include information for only the relevant Settlement Period. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO. Scheduling Coordinators wishing to buy back in the Hour-Ahead Market Regulation, Spinning Reserve, or Non-Spinning Reserve capacity sold to the ISO in the Day-Ahead Market pursuant to section 2.5.21 must do so by submitting a revised bid in the Hour-Ahead Market for the Ancillary Service and resource concerned.

2.5.11 Information To Be Submitted By Bidders.

Bids shall be submitted by Scheduling Coordinators acting on behalf of Participating Generators, and owners or operators of Loads. Bids must be in the format specified by

the ISO and include the bid information for each service described in the Schedules and Bids Protocol and such other information as the ISO may determine it requires to evaluate bids as published from time to time in ISO Protocols. The ISO will verify and respond to submitted bid data in accordance with Appendix E and the ISO Protocols. Bidders may submit new bids on a daily basis (or hourly basis for the Hour-Ahead Market).

2.5.12 Bid Evaluation Rules.

Bid evaluation shall be based on the following principles:

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

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

(c) for the Day-Ahead Market, the Day-Ahead bids shall be evaluated over the SCUC time horizon as set forth in Section 31.2.3.1.2.2;

(d) for the Hour-Ahead Market, the ISO shall evaluate bids over the SCUC time horizon as set forth in Section 31.3.2;

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

2.5.13 Evaluation of Ancillary Services Bids.

When Scheduling Coordinators bid into the Regulation, Spinning Reserve and Non-Spinning Reserve markets, they may bid the same capacity into as many of these markets as desired by providing the appropriate bid information to the ISO. Scheduling Coordinators shall submit Ancillary Services Bids in accordance with the Schedules and Bids Protocol. The ISO shall evaluate bids in the markets for Regulation, Spinning Reserve and Non-Spinning Reserve simultaneously as set forth in Section 31.2.3.1.3. A Scheduling Coordinator may specify capacity bid into only the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices for the Spinning Reserve, Non-Spinning Reserve, and Regulation markets.

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

2.5.14 [Not Used]

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2.5.15 [Not Used]

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2.5.16 [Not Used]

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2.5.18 Voltage Support.

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

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

The ISO shall select Participating Generator's Generating Units which have been certified for Voltage Support to provide this additional Voltage Support. Subject to any

locational requirements, the ISO shall select the least costly Generating Units from a computerized merit order stack to back down to produce additional Voltage Support in each location where Voltage Support is needed.

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

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

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

2.5.19 Black Start Capability and Energy Output.

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

2.5.20 Obligations for and Self Provision of Ancillary Services.

2.5.20.1 Ancillary Service Obligations. Each Scheduling Coordinator shall be assigned a share of the total Regulation, Spinning Reserve and Non-Spinning Reserve requirements by the ISO. Any references in this Tariff to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up or Regulation Down". The

share assigned to each Scheduling Coordinator is described in Section 2.5.20 and in Section 2.5.28 as that Scheduling Coordinator's obligation. Each Scheduling Coordinator's Regulation obligation in each Ancillary Services Region shall be pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (excluding exports) bears to the total metered Demand (excluding exports) served in each hour in that Ancillary Services Region. Each Scheduling Coordinator's Operating Reserve obligation in each Ancillary Services Region shall be pro rata based upon the same proportion as the ratio of the product of its percentage obligation based on metered output and the sum of its metered Demand and firm exports bears to the total of such products for all Scheduling Coordinators in the Ancillary Services Region. The Scheduling Coordinator's percentage obligation based on metered output shall be calculated as the sum of 5% of its real time Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from hydroelectric resources plus 7% of its Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from non-hydroelectric resources in that Ancillary Services Region, plus 100% of any Interruptible Imports and on-demand obligations which it schedules. Scheduling Coordinator obligations for each Ancillary Service will be calculated based on the requirement for each Ancillary Service as the ISO determines prior to the adjustment set forth in Section 2.5.3.6.

2.5.20.2 Right to Self Provide.

Each Scheduling Coordinator may choose to self provide all, or a portion, of its Regulation and Operating Reserve obligation in each Ancillary Services Region. The ISO shall schedule self provided Ancillary Services, Day-Ahead and Hour-Ahead, and Dispatch self provided Ancillary Services in real time. To the extent that a Scheduling Coordinator self provides, the ISO shall correspondingly reduce the quantity of the Ancillary Services

concerned, which it procures as described in Section 31.2.3.1.3. In accordance with Section 2.5.22.11 and Section 2.5.26.2, if a Scheduling Coordinator uses capacity scheduled to self-provide Spinning Reserve, or Non-Spinning Reserve to supply Uninstructed Imbalance Energy to the ISO from a Generating Unit, Dispatchable Load, or System Resource under circumstances that would cause the elimination of payments to the Scheduling Coordinator under Section 2.5.26.2 if the capacity had been bid and was selected by the ISO to supply the Ancillary Service, the Scheduling Coordinator shall pay to the ISO the amount of the payment that would be eliminated under that section. Scheduling Coordinators may trade Ancillary Services obligations so that any Scheduling Coordinator may reduce its Ancillary Services obligation through purchase of Ancillary Services capacity from another Scheduling Coordinator, or self-provide in excess of its obligation to sell Ancillary Services to another Scheduling Coordinator, subject to the limits specified under Section 2.5.20.5.2. If a Scheduling Coordinator's Day-Ahead self-provided Ancillary Service schedule is decreased in the Hour-Ahead Market, such decrease shall be deemed to be replaced pursuant to Section 31.3.4.

2.5.20.3 [Not Used]

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

(a) Regulation;

(b) Spinning Reserve; and

(c) Non-Spinning Reserve.

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

If, at any time after the issuance of Final Day-Ahead Schedules for the Trading Day and before the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day, the ISO determines that it requires Ancillary Services in addition to those included in the Final Day-Ahead Schedule (in the appropriate Ancillary Services Region if procuring zonally), the ISO may procure such additional Ancillary Services by providing Scheduling Coordinators with amended supplier schedules for the Day-Ahead Markets that include Ancillary Services for which previously submitted (but not selected) bids remain available and have not previously been withdrawn. The ISO shall select such Ancillary Services in price merit order (and in the relevant Ancillary Services Region). Such amended supplier schedules shall be provided to the Scheduling Coordinators no later than the close of the Hour-Ahead Market for the first Settlement Period of the Trading Day.

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above.

2.5.22 Rules For Real Time Dispatch of Imbalance Energy Resources.

2.5.22.1 Overview. During real time, the ISO shall dispatch Generating Units, Loads and System Resources in accordance with Section 31.4.3 to procure Imbalance Energy. In addition, the ISO may also need to purchase additional Ancillary Services if the services arranged in advance are used to provide Imbalance Energy, and such depletion needs to be recovered to meet reliability contingency requirements.

2.5.22.2 [Not Used]

2.5.22.3 Ancillary Services Dispatch. The ISO may dispatch Generating Units, Loads, System Units and System Resources contracted to provide Ancillary Services (either procured through the ISO's competitive market, or self provided by Scheduling Coordinators) to supply Imbalance Energy.

During normal operating conditions, the ISO shall dispatch the following resources to supply Imbalance Energy: (i) those Generating Units, Loads, System Units and System Resources having offered Supplemental Energy bids, and (ii) those Generating Units, Loads, System Units and System Resources that have contracted to provide Spinning and Non-Spinning Reserve, except for those resources that have indicated that the capacity reserved would be available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency. In the event of an unplanned Outage, a Contingency or a threatened or actual System Emergency, the ISO may also dispatch all other Generating Units, Loads, System Units and System Resources contracted to provide Spinning Reserve or Non-Spinning Reserve to supply Imbalance Energy. If a Generating Unit, Load, System Unit or System Resource, which is supplying Operating Reserve, is dispatched to provide Imbalance Energy, the ISO shall replace the Operating Reserve from the same or another resource within the time frame specified in the WSCC guidelines.

which are being self provided the Energy Bid shall be used to determine the position of the Generating Unit, Load, System Unit or System Resource in the merit order for real time Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3.

2.5.22.4 Supplemental Energy Bids. In addition to the Generating Units, Loads and System Resources which have been scheduled to provide Ancillary Services in the Day-Ahead and Hour-Ahead markets, the ISO may Dispatch Generating Units, Loads or System Resources for which Scheduling Coordinators have submitted Supplemental Energy bids to the Hour-Ahead Energy Market.

2.5.22.4.1 [Not Used]

2.5.22.4.2 [Not Used]

2.5.22.5 [Not Used]

2.5.22.6 [Not Used]

[Page Not Used]

shall be declared and labeled as non-conforming to the ISO's instructions, unless it has notified the ISO of an event that prevents it from performing its obligations within 30 minutes of the onset of such event,

cannot set the Dispatch Interval Locational Marginal Price and

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

The ISO will develop additional mechanisms to deter Generating Units, Dispatchable Load and System Resources from failing to perform according to Dispatch instructions, for example reduction in payments to Scheduling Coordinators, or suspension of the Scheduling Coordinator's Ancillary Services certificate for the Generating Unit, Dispatchable Load or System Resource concerned.

2.5.23 Pricing Imbalance Energy.

2.5.23.1 General Principles.

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

2.5.23.2 [Not Used]

2.5.23.2.1 [Not Used]

2.5.23.2.2 [Not Used]

2.5.23.3 [Not Used]

2.5.23.3.1 [Not Used]

2.5.23.3.2 [Not Used]

2.5.23.3.3 [Not Used]

2.5.24 Verification of Performance of Ancillary Services.

Availability of both contracted and self provided Ancillary Services shall be verified by the ISO by unannounced testing of Generating Units, Loads and System Resources, by auditing of

2.5.25.4 [Not Used]

2.5.25.5 Voltage Support. The ISO shall monitor a Generating Unit's response to Voltage Support instructions in order to determine compliance with Dispatch Instructions.

2.5.25.6 Black Start. The ISO may test the Black Start capability of a Generating Unit by issuing unannounced Dispatch Instructions requiring the Generating Unit to start on a Black Start basis. The ISO shall measure the response of the Generating Unit to determine compliance with the terms of the Black Start contract. The Scheduling Coordinator or Black Start Generator for the Generating Unit shall be paid the Generating Unit's contract price for the output under the Black Start test as set forth in Settlements and Billing Protocol Appendix G.

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

2.5.26.1 Penalties for Failure to Pass Tests. A Generating Unit, Dispatchable Load, System Unit or System Resource that fails an availability test, as determined under criteria to be established by the ISO, shall be deemed not to have been available to provide the Ancillary Service concerned or the relevant portion of that Service for the entire period the Generating Unit, Dispatchable Load, System Unit or System Resource was committed to

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

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

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

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

2.5.26.2.1 If the ISO determines that a Scheduling Coordinator has supplied Uninstructed Imbalance Energy to the ISO during a Dispatch Interval from the capacity of a Generating Unit, System Unit or System Resource that is obligated to supply Spinning Reserve or Non-Spinning Reserve to the ISO during such Dispatch Interval, payments to the Scheduling Coordinator representing the Generating Unit, System Unit or System Resource for the Ancillary Service capacity used to supply Uninstructed Imbalance Energy shall be eliminated to the extent of the deficiency, except to the extent (i) the deficiency in the availability of Ancillary Service capacity from the Generating Unit, System Unit or System Resource is attributable to control exercised by the ISO in that Dispatch Interval through AGC operation, an RMR Dispatch Notice, or dispatch to avoid an intervention in Market operations or to prevent a System Emergency; or (ii) a penalty is imposed under Section 2.5.26.1 with respect to the deficiency.

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

2.5.26.2.3 [Not Used]

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

2.5.26.2.5 Payment shall be eliminated first for any Spinning Reserve capacity for which the Generating Unit, Dispatchable Load, System Unit or System Resource would otherwise be entitled to payment. If the amount of Ancillary Service capacity from which the Generating Unit, System Unit or System Resource has supplied Uninstructed Imbalance Energy exceeds the amount of Spinning Reserve capacity for which it would otherwise be entitled to receive payment, payment shall be eliminated for Non-Spinning

Reserve capacity, until payment has been withheld for the full amount of Ancillary Service capacity from which the Generating Unit, Dispatchable Load, System Unit or System Resource supplied Uninstructed Imbalance Energy.

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

2.5.26.3 Rescission of Payments When Dispatch Instruction is Not Followed

If the total metered output of a Generating Unit, Dispatchable Load, System Unit or System Resource is insufficient to supply the amount of Instructed Imbalance Energy associated with a Dispatch instruction issued in accordance with a bid on Spinning Reserve or Non-Spinning Reserve in any Dispatch Interval, then the capacity payment associated with the difference between the total scheduled amount of each Ancillary Service for which Insufficient Energy was delivered, and the actual output attributed to the response to the Dispatch Instruction on each Ancillary Service, shall be rescinded. However, no capacity payment shall be rescinded if the shortfall in the metered output of the Generating Unit, Dispatchable Load, System Unit, or System Resource is less than a deadband amount published by ISO on the ISO Home Page at least twenty-four hours prior to the Dispatch Interval. For any Dispatch Interval with respect to which no

deadband amount has been published by the ISO, the deadband amount shall be zero MWH. If the Generating Unit, Dispatchable Load, System Unit or System Resource is scheduled to provide more than one Ancillary Service in the Settlement Period, then the actual output will be attributed first to Non-Spinning Reserve and finally to Spinning Reserve, and the capacity payments associated with the balance of each Ancillary Service shall be rescinded. If the same Ancillary Service is scheduled in both the Day Ahead and Hour Ahead Markets, then payments shall be rescinded in proportion to the amount of each Ancillary Service scheduled in each market.

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

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

2.5.26.6 Temporary Exemption from Rescission of Energy Payments Any Participating Load that has entered into a Participating Load Agreement and has responded to a Dispatch Instruction shall be exempt from Uninstructed Deviation Penalties in Section 11.2.4.1.2(d) in the hour of the Dispatch and for the following two (2) hours during the period beginning on June 15, 2000 and ending on the date specified in a notice ("Notice Terminating Temporary Exemption") to be issued by the ISO. Such notice shall be posted on the ISO Home Page and distributed to

2.5.27 [Not Used]

2.5.27.1 [Not Used]

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2.5.27.2 [Not Used]

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2.5.27.3 [Not Used]

[Page Not Used]

2.5.27.4 [Not Used]

2.5.27.5 [Not Used]

2.5.27.6 [Not Used]

2.5.27.7 [Not Used]

2.5.28 [Not Used]

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2.5.28.1 [Not Used]

2.5.28.2 [Not Used]

2.5.28.3 [Not Used]

2.5.28.4 [Not Used]

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2.5.28.5 [Not Used]

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2.5.28.6 [Not Used]

2.5.29 Public Dissemination of Information: Day-Ahead.

By 3:00 p.m. of the day preceding the Trading Day, the ISO shall make available to all Market Participants the following information on the scheduling of Ancillary Services:

Ancillary Service	Quantity Units	Period	Ancillary Services Region	Ancillary Services Marginal Price
Regulation/AGC	MW	Hourly	Region	$/MW
Spinning Reserve	MW	Hourly	Region	$/MW
Non-Spinning Reserve	MW	Hourly	Region	$/MW

2.5.30 Communication Protocols.

Communications between the ISO and Scheduling Coordinators shall be as described below:

2.5.30.1 Information Transfer from Scheduling Coordinator to ISO. Unless otherwise agreed by the ISO, Scheduling Coordinators who wish to schedule or bid Ancillary Services to the ISO must submit the information by direct computer link.

2.5.30.2 Submitting Information By Direct Computer Link. For Scheduling Coordinators submitting information by direct computer link, each such Scheduling Coordinator shall establish a network connection with the ISO through the WEnet network. This shall be a permanent link with the ISO. Link initialization procedures shall be necessary to establish the connection for the first time, and to re-establish the connection each time the connection is restored after a system or communication failure. In order to log in, each Scheduling Coordinator shall furnish the ISO with user ID and password.

3.3.4 MSS Operator Responsibilities.

Recognizing the ISO's responsibility to promote the efficient use and reliable operation of the ISO Controlled Grid and the Control Area consistent with the Applicable Reliability Criteria, each MSS Operator shall:

3.3.4.1 operate and maintain its facilities, in accordance with applicable safety and reliability standards, regulatory requirements, applicable operating guidelines, applicable rates, tariffs, statutes and regulations governing their provision of service to their End-Use Customers and Good Utility Practice so as to avoid any material adverse impact on the ISO Controlled Grid, it being understood that, if the MSS Operator does not so operate and maintain its facilities and the ISO concludes, after notice is provided to the MSS Operator, that such failure impairs or threatens to impair the reliability of the ISO Controlled Grid, the ISO may suspend MSS status, in accordance with this Section 3.3, until the MSS Operator demonstrates the ability and willingness to so operate and maintain its facilities;

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

3.3.4.3 coordinate with the ISO, other Participating TOs and Generators to ensure that ISO Controlled Grid Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with the protective systems of the MSS, other Participating TOs and Generators;

3.3.4.4 be responsible for any Reliability Must-Run Generation and Voltage Support required for reliability of the MSS, including the responsibility for any costs of such Reliability Must-Run Generation, and Voltage Support and may satisfy this requirement

through Generating Units owned by the MSS or under contract to the MSS;

3.3.4.5 be responsible for Black Start requirements for reliability of the MSS, however, if the MSS can self-provide this requirement, the MSS shall not pay its pro rata share of the Black Start requirement in accordance with Section 2.5.28.6; and

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

3.3.5 Scheduling by a MSS Operator. All Schedules submitted on behalf of a MSS Operator for the delivery of Energy and Ancillary Services to Loads connected to the MSS and for the delivery of Energy and Ancillary Services from Generating Units forming part of the MSS or System Units shall be submitted by a Scheduling Coordinator that complies with all applicable provisions of the ISO Tariff, which Scheduling Coordinator may be the MSS Operator, provided that the MSS Operator complies with all applicable requirements for Scheduling Coordinators.

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

3.3.5.2 The Scheduling Coordinator for the MSS will designate, in discrete quantities and with prices for both Ancillary Services and Energy: (1) Schedules in Day-Ahead and Hour-Ahead Energy markets (including schedules for internal Generation and internal Load within the MSS), (2) bids or self-provided Schedules for Regulation, Spinning

forth in this Section 4, have the right by agreement to delegate certain operational responsibilities to the relevant Participating TO or UDC pursuant to this Section 4. All information made available to UDCs by the ISO shall also be made available to Scheduling Coordinators. All information pertaining to the physical state or operation, maintenance and failure of the UDC Distribution System affecting the operation of the ISO Controlled Grid that is made available to the ISO by the UDC shall also be made available to Scheduling Coordinators upon receipt of reasonable notice.

4.2 Coordinating Maintenance Outages of UDC Facilities.

Each UDC and the Participating TO with which it is interconnected shall coordinate their Outage requirements that will have an effect on their transmission interconnection prior to the submission by that Participating TO of its maintenance Outage requirements under Section 2.3.3.

4.3 UDC Responsibilities.

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

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

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

5.11 [Not Used]

5.11.1 [Not Used]

5.11.2 [Not Used]

5.11.3 [Not Used]

5.11.4 [Not Used]

5.11.5 [Not Used]

5.12 Residual Unit Commitment

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

5.12.2 Participation.

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

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

5.2.12.3 System Resources. Scheduling Coordinators shall indicate to the ISO if they want any unused Day-Ahead Energy Bid from System Resources to participate in the Residual Unit Commitment Process as set forth in Section 5.12.5.2.

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

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

5.12.3 Data to be Submitted.

5.12.3.1 Scheduling Coordinators for Generating Units required to participate in or voluntarily participating in the Residual Unit Commitment Process shall submit the following information to the ISO in the form as specified by the ISO and posted on the ISO Home Page. Scheduling Coordinators for such Generating Units must also file periodic updates of this data upon the direction of either FERC or the ISO. The ISO will treat the information provided to the ISO in accordance with this Section 5.12.3.1 as confidential and will apply the procedures in Section 20.3.4 of this ISO Tariff with regard to requests for disclosure of such information.

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

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

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

5.12.4 Timing of the Residual Unit Commitment Process.

5.12.4.1 Submission of bids. The Residual Unit Commitment Process uses bids submitted to the Day-Ahead Market. Scheduling Coordinators shall notify the ISO of whether they want unused Day-Ahead Energy Bids to participate in the Residual Unit Commitment Process when they submit their Bids to the Day-Ahead Market.

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

5.12.5 Transmission for System Resources in the Residual Unit Commitment Process

(a) Transmission Outside the ISO Control Area

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

(b) ISO Control Area Transmission

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

5.12.5.1 [Not Used]

5.12.5.1.1 [Not Used]

5.12.5.1.2 [Not Used]

5.12.5.1.3 [Not Used]

5.12.5.1.4 Default Bids. The ISO shall use the same default bids for the Residual Unit Commitment Process that the ISO used in the Day-Ahead Market.

5.12.5.1.4.1 [Not Used]

5.12.5.1.4.1.1 [Not Used]

5.12.5.1.4.1.2 [Not Used]

5.12.5.1.4.1.3 [Not Used]

5.12.5.1.4.2 [Not Used]

5.12.5.1.4.2.1 [Not Used]

5.12.5.1.4.2.2 [Not Used]

5.12.5.1.4.2.3 [Not Used]

5.12.5.2 [Not Used]

5.12.5.2.1 [Not Used]

5.12.5.2.2 [Not Used]

5.12.5.2.3 [Not Used]

5.12.5.3 **[Not Used]**

5.12.5.3.1 **[Not Used]**

5.12.5.3.2 **[Not Used]**

5.12.5.4 **[Not Used]**

5.12.5.4.2 **[Not Used]**

5.12.5.4.3 **[Not Used]**

5.12.5.4.4 [Not Used]

5.12.5.4.5 [Not Used]

5.12.5.5 [Not Used]

5.12.5.5.1 [Not Used]

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 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 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 when selecting those resources in the Residual Unit Commitment Process.

5.12.7 Payments.

5.12.7.1 Generating Units.

5.12.7.1.1 Unrecovered Commitment Costs. The ISO shall pay Generating Units selected by the ISO in the Residual Unit Commitment Process their positive Unrecovered Commitment Costs.

5.12.7.1.1.1 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.

5.12.7.1.1.2 The Allocated Start-Up costs shall be the product of the Unit's Start-Up Cost (as submitted in Section 5.12.5.1.1.1) and a fraction equal to the number of Qualifying Hours divided by the number of the hours in the ISO Commitment Period.

5.12.7.1.1.2.1 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.

5.12.7.1.1.2.2 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.

5.12.7.1.1.2.3 ISO Commitment Period. The ISO Commitment Period begins when the Generating Unit is synchronized in response to the ISO selecting that Unit in the Residual 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.

5.12.7.1.1.2.4 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.

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 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 Locational Marginal Price for that 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 Dispatch Intervals in that hour, of the product of a) the product of 1) the number that is the Locational Marginal Price for that 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.

5.12.7.1.1.4.1 Imputed Cost for Gas-Fired Generating Units. The Imputed Cost for Gas-Fired Generating Units shall be the sum of 1) the product of a) the unit's average heat rate at the operating level instructed by the ISO; b) the operating level instructed by the ISO; and c) the proxy figure for natural gas costs posted on the ISO Home Page; and 2) $6.00.

5.12.7.1.1.4.2 Imputed Cost for Non-Gas-Fired Generating Units. The Imputed Cost for Non-Gas-Fired Generating Units shall be the cost at the operating level as instructed by the ISO as provided in accordance with 5.12.3.

5.12.7.1.2 Payment for Terminated Start-up. If 1) the ISO selects a Generating Unit in the Residual 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 5.12.3), except that in no case shall this payment exceed the start-up cost provided in accordance with 5.12.3.

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 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 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 Dispatch Interval Locational Marginal 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 Dispatch Interval Locational Marginal Price for that hour.

5.12.7.3 Dispatchable Load

5.12.7.3.1 Minimum Curtailment Payment. If the ISO selects Dispatchable Load in the Residual 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.

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

5.12.8.1.4 The Hourly Capacity Reservation Costs shall be, the sum, for all Generating Units and System Units selected in the Residual Unit Commitment Process for that hour, of the Capacity Payments made that hour in accordance with Section 5.12.7.1.3 and Section 5.12.7.4.1.

5.12.8.1.5 The Hourly Terminated Start-Up Costs shall be the sum, for all Generating Units selected in the Residual Unit Commitment Process for that hour, of the Terminated Start-Up Payments made in accordance with Section 5.12.7.1.2 divided by the number of hours the unit was in start-up when the start-up was terminated.

5.12.8.2 Total Underscheduling Hourly Unit Commitment Cost shall be the product of the Total Hourly Residual Unit Commitment Cost and a number equal to the lesser of 1) one (1) and 2) a number that is equal to a) the greater of zero and a number equal to the total ISO hourly Metered Demand less the total ISO Scheduled Demand divided by b) a number equal to the greater of zero and a number equal to the total ISO forecast Demand less the total ISO scheduled Demand, except that if total ISO forecast Demand equals total ISO scheduled Demand, the Total Underscheduling Hourly Unit Commitment Cost shall be zero.

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]

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

6.1.2.3 [Not Used]

6.1.2.4 WEnet shall serve as a bulletin board to enable Market Participants to inform one another of scheduling changes and trades made.

6.1.2.5 WEnet may be used by the ISO to communicate operating orders to the Scheduling Coordinators and other Market Participants, both in advance of actual operation and in real time. Such orders may include but are not limited to:

(a) Notifying Scheduling Coordinators and other Market Participants to be on call to provide Non-Spinning Reserve and Replacement Reserves and Black Start;

(b) Issuing start-up instructions;

(c) Stating the amount of Spinning Reserves to be carried;

(d) Requesting specific Ramping patterns;

(e) Indicating which Scheduling Coordinators and other Market Participants are to provide Regulation;

(f) Specifying the minimum amount of unloaded capacity that must be maintained in order to meet regulation requirements;

(g) Issuing shut-down instructions; and

(h) Specifying the voltage level and reactive reserve each Market Participant must maintain.

6.2 Reliable Operation of the WEnet.

6.2.1 Market Participants shall arrange access to WEnet through the Internet Service Provider.

6.2.2 The ISO shall arrange for the Internet Service Provider to provide a pathway for public Internet connectivity through the WEnet backbone to accommodate users other than Market Participants without the need for a separate, dedicated user data link. This public Internet connection may provide a reduced level of data exchange and reduced information concerning

the reliability and performance of the ISO Controlled Grid when compared to that provided to Market Participants through dedicated user data links.

6.3 Information to be Provided By Connected Entities to the ISO.

6.3.1 Each Participating TO and Connected Entity shall provide to the ISO:

6.3.1.1 A single and an alternative telephone number and a single and an alternative facsimile number by which the ISO may contact 24 hours a day a representative of the Participating TO or Connected Entity in, or in relation to, a System Emergency;

6.3.1.2 The names or titles of the Participating TO's or Connected Entity's representatives who may be contacted at such telephone and facsimile numbers.

6.3.2 Each representative specified pursuant to Section 6.3.1 shall be a person having appropriate experience, qualification, authority, responsibility and accountability within the Participating TO or the Connected Entity to act as the primary contact for the ISO in the event of a System Emergency.

6.3.3 The details required under this Section 6.3 shall at all times be maintained up to date and the Participating TO and the Connected Entity shall notify the ISO of any changes promptly and as far in advance as possible.

6.4 Failure or Corruption of the WEnet.

The ISO shall, in consultation with Scheduling Coordinators, make provision for procedures to be implemented in the event of a total or partial failure of WEnet or the material corruption of data on WEnet and include these procedures in the ISO Protocols. The ISO shall ensure that such alternative communications systems are tested periodically.

6.5 Confidentiality.

All information posted on WEnet shall be subject to the confidentiality obligations contained in Section 20.3 of this ISO Tariff.

6.6 Standards of Conduct.

The ISO and all Market Participants shall comply with their obligations, to the extent applicable, under the standards of conduct set out in 18 C.F.R. §37.

7. TRANSMISSION PRICING.

7.1 Access Charges.

All Market Participants withdrawing Energy from the ISO Controlled Grid shall pay Access Charges in accordance with this Section 7.1. Prior to the transition date determined under Section 4 of Schedule 3 to Appendix F, the Access Charge for each Participating TO shall be determined in accordance with the principles set forth in this Section 7.1 and in Section 5 of the TO Tariff. The Access Charge shall comprise of two components, which together shall be designed to recover each Participating TO's Transmission Revenue Requirement. The first component shall be based on the Transmission Revenue Requirement without any adjustment for revenues associated with Wheeling and Usage Charges ("Transmission Revenue Credits"). The second component shall be based on the proceeds of the Transmission Revenue Balancing Account (TRBA) which shall be designed to flow through to the Participating TO's Transmission Revenue Credits, which are calculated in accordance with Section 5 of the TO Tariff.

Commencing on the transition date determined under Section 4 of Schedule 3 to Appendix F, the Access Charges shall be paid by the UDC or MSS delivering the Energy for the supply of Gross Load and by Scheduling Coordinators serving Gross Load of End-Use Customers not directly connected to the facilities of a UDC or MSS and shall consist, where

7.1.3 Disbursement of High Voltage Access Charge and Transition Charge Revenues.

The ISO shall collect and pay, on a monthly basis, to Participating TOs all High Voltage Access Charge and Transition Charge revenues at the same time as other ISO charges and payments are settled. High Voltage Access Charge revenues received with respect to the High Voltage Access Charge and the Transition Charge shall be distributed to Participating TOs in accordance with Appendix F, Schedule 3, Section 10.

7.1.3.1 [Not Used]

7.1.3.2 [Not Used]

7.1.3.3 [Not Used]

7.1.3.4 [Not Used]

7.1.3.5 [Not Used]

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 Section 31.2.3.2.8.

7.1.4.1 Wheeling Access Charge. The Wheeling Access Charge Charge shall be determined by the TAC Area and transmission ownership or Entitlement, less all Encumbrances, associated with the Scheduling Point at which the Energy exits the ISO Controlled Grid. The Wheeling

7.1.6.2 Addition of New Facilities After ISO Implementation. The costs of transmission facilities placed in service after the ISO Operations Date shall be recovered consistent with the cost recovery determinations made pursuant to Section 3.2.7.

7.1.6.3 Effect on Tax-Exempt Status. Nothing in this Section shall compel any Participating TO to violate any restrictions applicable to facilities financed with tax-exempt bonds or contractual restrictions and covenants regarding the use of transmission facilities existing as of December 20, 1995.

7.2 [Not Used]

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7.4 [Not Used]

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7.5 FERC Annual Charges.

7.5.1 Obligation for FERC Annual Charges.

7.5.1.1 Each Scheduling Coordinator shall be obligated to pay for the FERC Annual Charges for its use of the ISO Controlled Grid to transmit electricity, including any use of the ISO Controlled Grid through Existing Contracts scheduled by the Scheduling Coordinator. Any FERC Annual Charges to be assessed by FERC against the ISO for such use of the ISO Controlled Grid shall

8.3.2 Inter-Zonal Scheduling Charge.

The Inter-Zonal Scheduling Charge for each Scheduling Coordinator is calculated as the product of the rate for the Inter-Zonal Scheduling Charge and the absolute value of the net scheduled inter-zonal flow (excluding ETCs) per path for that Scheduling Coordinator. The rate for the Inter-Zonal Scheduling Charge is determined by dividing the GMC costs allocated to this service category by the total Scheduling Coordinators' inter-zonal scheduled flow (excluding ETCs) per path, according to the formula in Schedule 1 of this Tariff.

8.3.3 Ancillary Services and Real-Time Energy Operations Charge.

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

8.4 Calculation and Adjustment of the Grid Management Charge.

The three charges set forth in Section 8.3 that comprise the Grid Management Charge shall be calculated annually by summing the Operating Costs (less any available expense recoveries), Financing Costs, and Operating and Capital Reserves Costs associated with each of the three

ISO services, to obtain a total Revenue Requirement. A separate Revenue Requirement for each component of the GMC shall be established by dividing the Revenue Requirement for the ISO as a whole and then assigning such costs to the three service categories. The Revenue Requirement for each service then shall be divided by the forecast

10. METERING.

10.1 Applicability. Unless otherwise expressly stated to the contrary, the requirements set forth in these Sections 10.1 to 10.5 inclusive apply only to ISO Metered Entities.

10.2 Responsibilities of ISO Metered Entities

10.2.1 Duty to Provide Meter Data.

ISO Metered Entities shall ensure that Meter Data from their meters directly connected to the ISO Controlled Grid or at interconnections thereto, is made available to the ISO revenue meter data acquisition and processing system in accordance with the requirements of these Sections 10.1 to 10.5 and the ISO metering protocols. Pursuant to this obligation, the ISO shall establish revenue metering protocols for such ISO Metered Entities.

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. 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.

representing the relevant ISO Metered Entity that supplied the data and shall not be obtained directly from the ISO on any basis including, without limitation, by the polling of the ISO's revenue meter data acquisition and processing system via WEnet.

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, 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.

10.3.2 Security and Meter Data Validation Procedures.

The meter service agreement for each ISO Metered Entity and the ISO metering protocols shall set out, in such detail as the ISO may deem necessary, the Meter Data security and validation procedures that the ISO shall apply to the Meter Data made available by each ISO Metered Entity. The ISO may base the security and validation procedures on historical data or an appropriate alternative data source. The ISO shall correct or replace or cause to be corrected or replaced inaccurate or missing data. The procedure may

11. ISO SETTLEMENTS AND BILLING.

11.1 Settlement Principles.

11.1.1 The ISO shall calculate, account for and settle transactions in accordance with the following principles:

11.1.2 The ISO shall be responsible for calculating Settlement balances for all transactions carried out by Scheduling Coordinators on the ISO Controlled Grid in each Settlement Period;

11.1.3 The ISO shall carry out all Settlements in accordance with Meter Data provided pursuant to the requirements of Section 10 of this ISO Tariff;

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

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

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) Ancillary Services charges;

(3) Imbalance Energy charges;

(4) Usage Charges;

(5) High Voltage Access Charges and Transition Charges;

(6) Wheeling Access Charges;

(7) Voltage Support and Black Start charges; and

(8) 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]

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.

11.2.4 Imbalance Energy.

The ISO shall calculate, account for and settle Imbalance Energy in the Real Time Market for each Dispatch Interval for the relevant Location 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 Instructions. The Instructed Imbalance Energy will be calculated based on all Dispatch Instructions taking into account applicable ramp rates

and time delays. All Dispatch Instructions 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 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 Interval in accordance with Section 31.4.3.4.2 and the Settlement and Billing Protocol Appendix D.

11.2.4.1.1 Settlement for Instructed Imbalance Energy

Instructed Imbalance Energy attributable to each Scheduling Coordinator in each Dispatch Interval shall be deemed to be sold or purchased, as the case may 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 Interval in accordance with Section 31.4.3.4.1 and the Settlement and Billing Protocol Appendix D.

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 in each Dispatch Interval;

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) The Uninstructed Deviation Penalty will not apply to Interconnection Schedules if a pre-Dispatch Instruction is declined or not delivered. 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) The Uninstructed Deviation Penalty will not apply to Load, other than Dispatchable Load; for Dispatchable Load, the Uninstructed Deviation Penalty will not apply for the duration of the relevant Minimum Down Time;

e) 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) 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 intermittent Resources adopted by the ISO and published on the ISO Home Page or Regulatory Must-Run Generation. No other applicable charges will be affected by this exemption. Uninstructed Deviation Penalty also will not apply to Qualifying Facilities that have not executed a Participating Generator Agreement (PGA), pending resolution of QF-PGA issues at the Commission;

g) 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) 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) 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) The tolerance band for the application of the Uninstructed Deviation Penalties to Generators or aggregated Generators initially will be the Energy produced in a 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) The tolerance band for the application of the Uninstructed Deviation Penalties to Dispatchable Loads initially will be equal to the Energy produced in a Dispatch Interval by the greater of five (5) MW or three percent (3%) of the relevant final Hour-Ahead Schedule;

l) The Uninstructed Deviation Penalty will not apply when the Dispatch Interval Locational Marginal Price is negative or zero;

m) The Uninstructed Deviation Penalty for positive Uninstructed Imbalance Energy will be the amount of the Uninstructed Imbalance Energy in excess of the tolerance band multiplied by a price that initially will be equal to 100% of the corresponding Dispatch Interval Locational Marginal 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) The Uninstructed Deviation Penalty for negative Uninstructed Imbalance Energy will be the amount of the Uninstructed Imbalance Energy in excess of the tolerance band multiplied by a price that initially will be initially equal to 25% of the corresponding Dispatch Interval Locational Marginal Price; and the net effect of the Uninstructed Deviation Penalty and Uninstructed Imbalance Energy settlement initially will be that any such Energy will be charged at 125% of the corresponding Locational Marginal Price;

o) The Uninstructed Deviation Penalty will not apply to deviations from Energy delivered as part of a scheduled test so long as the test has been scheduled by the Scheduling Coordinator with the ISO or the ISO has initiated as test for the purposes of validating unit performance;

p) The Uninstructed Deviation Penalty will apply to Exceptional Dispatches;

q) Generating Units, Dispatchable Load and dispatchable Interconnection resources with negative Uninstructed Imbalance Energy will be exempted from the Uninstructed Deviation Penalty if the Generating Unit, Dispatchable Load or dispatchable Interconnection resource was physically incapable of delivering the expected Energy, provided that the Generating Unit, Dispatchable Load 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 or dispatchable Interconnection resource must notify ISO operations staff of its reasons for failing to deliver the expected Energy in accordance with Section 2.3.3.9.2 and must provide information to the ISO that verifies the reason the resource failed to comply with the Dispatch Instruction within 72 hours of the operating hour in which the instruction is issued; and

r) Operational adjustments associated with interchange schedules making use of Existing Contract rights shall not be subject to the Uninstructed Deviation Penalty.

Amounts collected as Uninstructed Deviation Penalties shall first be assigned to reduce the portion of Residual Unit Commitment costs that would otherwise be included in Total Excess Hourly Unit Commitment Cost, pursuant to Section 5.12.8.3. Any remaining amounts of collected Uninstructed Deviation Penalties shall next be assigned to reduce the portion of above-MCP costs that would otherwise be assigned pro rata to all Scheduling Coordinators in that 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 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 option (a).

11.2.4.2.1 [Not Used]

11.2.4.2.2 Allocation of Above-MCP Costs

For each Dispatch Interval, the above-MCP costs incurred by the ISO as a result of Instructed Imbalance Energy and Dispatch instructions 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 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 Instructions 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 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 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.

11.2.4.3 Unaccounted For Energy (UFE)

For settlement purposes, UFE is treated as Imbalance Energy. For each 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 Dispatch Interval Locational Marginal 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 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. 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 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 Dispatch Interval deviations by each Participating Intermittent Resource were priced at the appropriate Dispatch Interval Locational Marginal Price specified in Settlement and Billing Protocol Appendix D 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 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]

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.

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. 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 as determined in accordance with Settlement and Billing Protocol Appendix C;

b) charges at the Ancillary Services Marginal Price as determined in accordance with Settlement and Billing Protocol Appendix C;

c) payments for Energy delivered in response to incremental Dispatch Instructions at the Marginal Proxy Clearing Price at the Location or the Locational Marginal Price, as applicable; and

d) charges for Net Negative Uninstructed Deviations.

11.2.13 Emissions Cost Charges

The ISO shall calculate, account for and settle charges and payments for Emissions Costs in accordance with Sections 2.5.23.3.6 of this ISO Tariff.

11.3 Billing and Payment Process.

11.3.1 The billing and payment process shall be based on the issuance of Preliminary and Final Settlement Statements for each Settlement Period in each Trading Day.

11.3.2 Payment for the charges referred to in Section 11.1.6 of the ISO Tariff (except for the charges payable under long term contracts) for each Trading Day in each calendar month shall be made five (5) Business Days after issuance of the Preliminary Settlement Statement for the last day of the relevant calendar month. Payment for adjustments will be made five (5) Business Days after issuance of the Final Settlement Statement for the last day of the relevant month. Payments for FERC Annual Charges will be made in accordance with Section 7.5 of this ISO Tariff.

11.3.3 [Not used]

11.3.4 [Not used]

11.4 General Principles for Production of Settlement Statements.

11.4.1 Basis of Settlement. The basis of each Settlement Statement shall be the debiting or crediting of an account in the name of the relevant Scheduling

Coordinator in the general ledger set up by the ISO to reflect all transactions, charges or payments settled by the ISO.

11.4.2 Right to Dispute.

All Scheduling Coordinators shall have the right to dispute any item or calculation set forth in any Preliminary Settlement Statement in accordance with 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 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

Departmental Secretary to take such steps as are necessary to give effect to any provisions of this Tariff that are not enforceable against the federal entity.

(c) To the extent that the ISO suffers any loss as a result of being unable to enforce any indemnity as a result of such enforcement being in violation of federal laws or regulations to which it is entitled under the Tariff under this Section or otherwise, it shall be entitled to recover such loss through the Grid Management Charge.

21. [Not Used]

22. [Not Used]

[Page Not Used]

23. [Not Used]

24. [Not Used]

25. [Not Used]

26. [Not Used]

27. TEMPORARY RULE LIMITING ADJUSTMENT BIDS APPLICABLE TO DISPATCHABLE LOADS AND EXPORT

27.1 Application and Termination

The temporary change limiting Adjustment Bids for Dispatchable Loads and exports set out in Section 27.2 shall continue in effect until such time as the Chief Executive Officer of the ISO posts a notice ("Notice of Full-Scale Operations"), on the ISO Home Page specifying the date on

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.

31.2.3.1.1 Formulation

The objective of the Security Constrained Unit Commitment shall be to minimize the overall cost of Day-Ahead Energy and Ancillary Services procurement over the entire set of hours that shall consist of the time horizon, subject to network constraints and resource operating constraints. The overall procurement cost shall be determined by the total of the start-up and minimum load costs of ISO-committed resources, the Energy bids of all scheduled resources, and the Ancillary Services bids of resources selected to provide Ancillary Services. Network constraints include power flow limits on transmission facilities, voltage limits, and limits on other transmission controls. Resource constraints include operating limits and inter-temporal constraints. The technical formulation of SCUC is given and discussed in Appendix B.

31.2.3.1.2 Unit Commitment

31.2.3.1.2.1 Unit Commitment Definitions

The following definitions are used in this Tariff in association with Unit Commitment:

- *Time period.* The unit of time for scheduling activities, currently an hour. Resource Schedules are constant throughout the time period.

- *Time horizon.* A number of contiguous time periods over which an optimal Schedule is produced.
- *Commitment status.* The dual on/off state for each unit in each time period. A unit is off when it is offline or in the process of starting up or shutting down. A unit is on when it is online and synchronized with the grid. An off-on transition signifies a start-up and an on-off transition signifies a shutdown.
- *Unit operating constraints.* The feasible scheduling of generating resources over a time horizon requires consideration of a multitude of operating constraints:
    - *Availability status.* The status of a unit with respect to planned or forced outages.
    - *Start-up time.* The time required for a unit to start up after notification.
    - *Minimum up time (MUT).* The minimum time that a unit must stay on after a start-up.
    - *Minimum and maximum operating limits.* The power output limits of a unit while it is on. The minimum operating limit is also referred to as the *minimum load*.
    - *Shutdown time.* The time required for a unit to shut down.
    - *Minimum down time (MDT).* The minimum time that a unit must stay off after a shutdown. The minimum down time includes the shutdown and start-up time.
    - *Maximum number of daily start-ups*. The maximum number of times that a unit is allowed to start up within a day.
    - *Ramp rate.* The rate at which a unit increases or decreases its power output to perform schedule changes across time periods.
    - *Energy limit.* The limit on the total Energy output of an energy-limited resource over the time horizon.

- *Operational dead-bands*. Operating ranges in which the resource produces Energy but is not dispatchable.

Availability, and start-up and minimum up/down times (rounded up to the next integer multiple of the time period) affect the commitment status, whereas ramp rate and operating/energy limits affect the schedule of units. The maximum number of daily start-ups limits unit cycling within a day.

- *Unit costs.* The optimal scheduling of generating resources over a time horizon requires consideration of a multitude of unit costs:
  - *Start-up cost.* The cost incurred when a unit starts up. This cost is a function of past down time. The start-up cost generally increases as down time increases.
  - *Shutdown cost.* The cost incurred when a unit shuts down. For simplicity, the shutdown cost is included in the start-up cost.
  - *Minimum load cost.* The cost incurred when a unit is operating at minimum load.
  - *Incremental energy cost.* The incremental Energy cost (the cost of producing the next increment of power) of a unit at a given operating point.

The optimal Schedules produced by SCUC minimize the start-up and Energy cost of all resources over the entire time horizon. The Energy cost is calculated as the minimum load cost plus the integral of the incremental Energy cost from minimum load to final schedule.

- *Commitment period.* The time span of contiguous time periods where a unit is on. The commitment period extends from a start-up to a shutdown and it may span several days. The commitment period may not be less than the MUT, however, for practical reasons, the commitment period will be limited to a single day, in which case it may split over several contiguous commitment periods.

- *Self-commitment period.* The portion of the commitment period of a unit that submits Energy Schedules or is selected to provide Ancillary Services, except for units providing Non-Spinning Reserve that can start and synchronize to the grid in less than ten minutes, typically hydro units and combustion turbines (CTs). The self-commitment period may include time periods where the unit does not submit Schedules or is awarded Ancillary Services, if it is determined by inference that the unit must be on due to MUT/MDT constraints. For example, the self-commitment period of a unit that self-commits in hour h will be $[h, h + MUT]$. Similarly, the self-commitment period of a unit that self-commits in hours h and $h + n$ will be $[h, h + \max(n, MUT)]$ if $n < MUT + MDT$.

- *ISO-commitment period.* The portion of the commitment period that is not a self-commitment period.

- *Qualifying hour.* The hour of an ISO-commitment period when a unit is not Dispatched under its RMR Contract.

- *Unit Commitment cost.* The unit commitment cost over a commitment period is composed of the minimum load cost for each qualifying hour in ISO-commitment periods, plus the start-up cost if 1) there is no self-commitment within the commitment period; 2) the unit is required to start and 3) it actually starts up. A unit that incurs start-up costs at the direction of the ISO but does not complete the start-up shall be treated in accordance with Section 5.12.7.1.2. The unit may not be required to start if the commitment period immediately follows a previous commitment period. Units are not eligible to recover start-up costs that they do not actually incur. For example, a unit may remain on from a prior commitment period or may fail to start-up as instructed.

- *Unrecovered Commitment Cost.* The portion of the unit commitment cost over all qualifying hours in a commitment period that is not recovered from market revenues from the Day-Ahead and Hour-Ahead Energy and Ancillary Services markets and the Real-Time Imbalance Energy market during the same hours, as calculated in SABP Appendix H.

31.2.3.1.2.2 Time Horizon

Although the objective of SCUC is to produce optimal Schedules for each hour of the Trading Day, a time horizon longer than 24 hours is required for efficient scheduling. The time horizon should include at the minimum the peak hours of the day that follows the Trading Day so that SCUC will not unnecessarily cycle long-start units at the end of the Trading Day. To consider the lower Demand levels during weekends and holidays, and also the Energy limits of Energy-limited resources, the time horizon would need to be even longer. Depending on the capability and performance of the software and hardware that the ISO will procure and use for the SCUC implementation, the time horizon shall be a *rolling window* of up to five (5) days (120 hours), starting with the Trading Day. The SCUC shall replicate Schedules and Bids submitted for the Trading Day shall be for the following four days (with appropriate adjustments for Demand Forecast changes) to provide for continuity. The resulting optimal Schedules for the Trading Day shall constitute the final Day-Ahead Energy and Ancillary Services Schedules. The optimal Schedules for the remaining four days past the Trading Day will be for the ISO's advisory use only. The ISO shall provide sufficient advance notice to Units with start-up times greater than 24 hours that the Advisory schedules indicate should be started. The resource shall be required to remain committed as set forth in Section 2.3.1.2.

31.2.3.1.2.3 Self-Commitment

Resources that submit preferred Energy Schedules in a given hour, or are selected to provide Ancillary Services (bid or self-provided), except for units providing Non-Spinning Reserve that can start and synchronize to the grid in less than ten minutes, shall be deemed self-committed by SCUC in that hour.

SCUC will enforce operating constraints for self-committed resources. As a result, these resources may be deemed self-committed (and scheduled to at least their minimum load) also during hours that they do not submit preferred Energy Schedules, if the resources are required to be on due to their MUT and/or MDT constraints. Furthermore, preferred Energy Schedules across consecutive hours must be consistent with the relevant ramp rate capabilities, otherwise the Energy Schedules will be adjusted accordingly.

The preferred Energy Schedules of self-committed resources shall be optimized using submitted Energy bids. The adjustments shall bound the final Energy Schedules within the capacity range of the submitted Energy bids and within the relevant minimum and maximum operating limits, taking into account Ancillary Services commitments. However, if the submitted Energy bids are insufficient to resolve Congestion, preferred Energy Schedules may be adjusted, outside the capacity range of submitted Energy bids, or even when no Energy bids are submitted, but within the resource's operating capability, due to pro rata Schedule adjustments in accordance with Section 31.2.3.1.4.2. Moreover, SCUC may de-commit self-committed resources if this measure is necessary to address overgeneration conditions.

SCUC will not consider start-up and minimum load cost bids from self-committed units. Resources shall not be eligible for Unrecovered Commitment Cost compensation during self-committed periods, as set forth in Section 31.2.3.1.2.1.

31.2.3.1.2.4 ISO-Commitment

Resources may submit three-part bids in accordance with Section 31.2.3.1.4.4 so that SCUC may optimally commit and schedule these resources to meet Energy, Ancillary Services, or Congestion Management requirements. SCUC will enforce operating constraints for ISO-committed resources. The final Energy Schedules shall be within the capacity range of the submitted Energy bids and within the relevant minimum and maximum operating limits, taking into account Ancillary Services commitments.

However, if the submitted Energy bids are insufficient to resolve Congestion, final Energy Schedules may exceed the upper range of submitted Energy bids due to pro rata Schedule adjustments in accordance with Section 31.2.3.1.4.2 but may not exceed the maximum capability of the resources as expressed to the ISO via the outage coordination process.

Resources may be eligible for Unrecovered Commitment Cost compensation during ISO-committed periods, as set forth in Section 31.2.3.4.4.1.1.1.

31.2.3.1.3 Ancillary Services Procurement

SCUC shall procure Ancillary Services at least cost simultaneous with the scheduling of Day-Ahead Energy for each hour of the Trading Day. Scheduling Coordinators may either self-provide Ancillary Services or they may submit a capacity reservation bid.

31.2.3.1.3.1 Ancillary Services Requirements

Ancillary Services prices and procurement may vary regionally due to regional Ancillary Services procurement constraints that may be enforced in SCUC for reliability purposes. The Ancillary Services requirements, Ancillary Services Regions, and regional procurement constraints shall be determined based on the Day-Ahead Demand Forecast and anticipated Congestion conditions, in accordance with the Ancillary Services Requirements Protocol. This information shall be published prior to the Day-Ahead market in accordance with Section 31.2.1.2. The Ancillary Services regional constraints may impose a minimum or a maximum of Ancillary Services requirements in a given region. These constraints can be used to enforce a minimum regional requirement for reliability purposes, or limit Ancillary Services imports from inter-ties.

31.2.3.1.3.2 Ancillary Services Self-Provision

Scheduling Coordinators may self-provide Ancillary Services as set forth in Section 2.5.7.4.

31.2.3.1.3.3 Ancillary Services Substitutability

SCUC shall allow a) that amount of Regulation Up that can be delivered in ten minutes to satisfy Spinning and Non-Spinning Reserve requirements, and b) Spinning Reserve to satisfy Non-Spinning Reserve requirements, if this substitution would result in a lower overall Ancillary Services and Energy procurement cost.

31.2.3.1.4 Energy Market and Congestion Management

SCUC shall perform Congestion Management simultaneous with Ancillary Services procurement and the scheduling of Day-Ahead Energy for each hour of the Trading Day. Congestion Management is the process where Energy schedules are adjusted to eliminate network constraint violations and minimize the cost of serving Demand.

31.2.3.1.4.1 Modeling

31.2.3.1.4.1.1 Network Model

SCUC shall use the Full Network Model. The Full Network Model will be continuously updated to reflect new transmission and generation projects. Transmission and generation facilities shall be in or out of service in the Full Network Model to reflect the expected system conditions in each hour of the Trading Day.

The Full Network Model shall include a reduced equivalent network for systems external to the ISO Controlled Grid. The modeling detail of the external systems will depend on the level of information available about external Schedules (Supply and Demand outside the ISO Controlled Grid).

31.2.3.1.4.1.2 Transmission Losses

The Full Network Model shall be an AC network model that includes resistances to reasonably account for transmission losses. Therefore, the final Day-Ahead Energy Schedules for Supply shall exceed the final Day-Ahead Energy Schedules for Demand and exports by the amount of transmission losses in the interconnected network. SCUC shall optimally adjust resource Schedules to cover transmission losses.

31.2.3.1.4.1.3 Network Constraints

SCUC shall enforce constraints on transmission lines, transformers, and groups of transmission branches that compose transmission interfaces. Most of these constraints shall be thermal limits on the power flow through the transmission facilities. However, certain constraints may impose more restrictive limits on power flow. These limits will take into account contingencies and reliability considerations, some of which are represented by Nomograms.

31.2.3.1.4.1.4 SCUC Controls

To the extent practical, SCUC controls shall consist of the following: generator real and reactive power output, import and export levels, Demand side management, transformer tap controls, switched reactive devices, High Voltage Direct Current controls, and others.

31.2.3.1.4.2 Default Energy Bids

To alleviate Congestion and produce feasible final Day-Ahead Energy and Ancillary Services Schedules, SCUC may need to adjust resource schedules outside the capacity range of submitted Energy bids. The resource schedule adjustments outside of the capacity range of submitted Energy bids are referred to as "uneconomic adjustments." Uneconomic adjustments shall be priced at the applicable Bid Caps, in accordance with Section 28.1. Incremental uneconomic adjustments for generation and decremental uneconomic adjustments for load and exports shall be priced at the Bid

Ceiling, whereas decremental uneconomic adjustments for generation and imports shall be priced at the Bid Floor. Incremental uneconomic adjustments for generating units shall extend up to their upper operating limit as listed in the Master File and as modified by any limitations reported to the ISO, less any self-provided Ancillary Services capacity. The upper regulating limit shall be used if the unit is scheduled to provide Regulation Up. Decremental uneconomic adjustments for generating units shall extend down to their lower operating limit plus capacity selected for Regulation Down. The lower regulating limit shall be used if the unit is scheduled to provide Regulation Down. Decremental uneconomic adjustments for imports, exports, and Demand shall extend down to zero MW.

Although all uneconomic adjustments shall be priced at the applicable bid limits, SCUC shall enforce different scheduling priorities among them. Therefore, uneconomic adjustments shall take place in increasing scheduling priority order, from lowest to highest, as needed to resolve Congestion. The different classes of uneconomic adjustments are described in the following subsections in decreasing scheduling priority.

31.2.3.1.4.2.1 Existing Contract Sources and Sinks

Existing Contract Schedules shall be balanced supply and demand Schedules with specified supply sources and demand sinks, and no Energy bids, in accordance with Section 31.2.3.2.6. Existing Contract Schedules shall be given the highest scheduling priority among uneconomic adjustments. Therefore, Existing Contract Schedules may be adjusted only after all other resource adjustments are exhausted. If adjusted, Existing Contract Schedules shall remain balanced.

31.2.3.1.4.2.2 Point-To-Point Firm Transmission Right Sources and Sinks

Point-To-Point (PTP) Firm Transmission Rights (FTRs) optionally provide FTR holders scheduling priority in the Day-Ahead market, in accordance with Section 9.1.1. PTP FTR Schedules are balanced supply and demand Schedules with specified Sources and Sinks, and no Energy bids, in accordance

with Section 31.2.3.2.7. PTP FTR Schedules shall be given the second highest scheduling priority among penalty adjustments after Existing Contract Schedules. Therefore, PTP FTR Schedules may be adjusted only after all other effective non-Existing Contract Schedule adjustments are exhausted. If adjusted, PTP FTR Schedules shall remain balanced.

31.2.3.1.4.2.3 RMR Energy

RMR Energy bid as a Price Taker shall be given the next highest scheduling priority after Existing Contract Schedules and FTR Schedules.

31.2.3.1.4.2.4 Supply and Demand Price Takers

Supply and Demand Price Takers are Supply and Demand Schedules (or portions thereof) without Energy bids. Supply price takers are selling Energy in the Day-Ahead Market at any price down to the Bid Floor. Similarly, Demand Price Takers are buying Energy in the Day-Ahead Market at any price up to the Bid Ceiling. Consequently, SCUC shall not adjust these Schedules until all other Schedules with Energy bids are fully adjusted.

The Schedules of any Demand or export bid as a Price Taker may be reduced when the Locational Marginal Price at their Location reaches the Bid Ceiling.

31.2.3.1.4.3 Locational Marginal Pricing

SCUC shall calculate Locational Marginal Prices (LMPs) for Energy and Ancillary Services Marginal Prices (ASMPs), as described in Tariff Appendix K. The LMPs for Energy shall be calculated for each network node and Load Aggregation Point or Trading Hub, and shall be used for Energy Settlements in accordance with Section 31.2.3.4.1. The ASMPs shall be calculated for each region and shall be used for Ancillary Services Settlements in accordance with Section 31.2.3.4.2.

The LMP at a network node, also referred to as the nodal price, is the marginal cost of serving the next increment of Demand at that node. The LMP is composed of the system marginal cost of Energy, the marginal cost of transmission losses, and the marginal cost of binding network constraints, i.e., network constraints that are active at the optimal solution prohibiting a lower cost outcome.

The LMP at a Load Aggregation Point or Trading Hub shall be the weighted average of the nodal prices of all underlying nodes so that the Energy Settlement using the LMP at the Load Aggregation Point or Trading Hub is equal to the Energy Settlement at all underlying nodes using the corresponding nodal prices. The load distribution from the Load Aggregation Point or Trading Hub down to the underlying nodes shall be determined by the relevant Load Distribution Factors (LDFs). The LDFs for Trading Hubs and Load Zones shall be used in accordance with Section 31.2.3.2.1 and published prior to the Day-Ahead market in accordance with Section 31.2.1.5. The LDFs for Customer Aggregations shall be validated and used in accordance with Section 31.2.3.2.1.2.

The ASMP for a given Ancillary Service in a given Ancillary Service Region is the marginal cost of providing that service in that region, which is the highest cost for providing that service among all selected resources in that region. The Ancillary Service cost for a given resource is its capacity reservation bid for that service plus the opportunity cost of reserved capacity for that service. The opportunity cost of reserved capacity is the difference between the LMP at the location of the resource and the Energy bid of the resource at its Energy Schedule. There is no opportunity cost for providing any Ancillary Service from Demand. There is also no opportunity cost for Ancillary Services provided by imports since the associated capacity is not linked to Energy Schedules.

31.2.3.1.4.4. Ancillary Services and Congestion

SCUC shall use regional procurement constraints when determining Ancillary Services requirements. SCUC shall not reserve Available Transmission Capacity (ATC) within regions for Ancillary Services. Similarly, no ATC shall be reserved for Ancillary Services between regions, with the only exception of

inter-tie capacity in the import direction for Ancillary Services from imports. SCUC shall allocate inter-tie capacity in the import direction among net Energy imports and Ancillary Services from imports to minimize total cost. If an inter-tie is congested in the import direction, the marginal cost of ATC reserved for Ancillary Services imports shall be charged explicitly to the relevant Ancillary Services providers, in accordance with Section 31.2.3.4.2.3. The marginal cost of ATC reservation for Ancillary Services imports shall be the shadow price of the congested inter-tie (i.e., the marginal cost of relieving the congestion on that inter-tie, as calculated by SCUC), if the inter-tie is congested in the import direction. Consequently, the loop flow due to the external network equivalent shall be ignored for Ancillary Services imports.

31.2.3.1.4.5 Local Market Power Bid Mitigation

If the ISO must Dispatch a Generating Unit as a direct result of Congestion within the ISO Controlled Grid that cannot be managed competitively in either the Day-Ahead, Hour-Ahead, or real-time Imbalance Energy Markets, the ISO shall, prior to establishing final LMPs, set the price of the bid from that Generating Unit equal to the default Energy bid price of that Generating Unit as determined in accordance with Sections 5.12.5.1.4.1.3 and 5.12.5.1.4.2.3. For Generating Units not subject to the default Energy bid prices described in Sections 5.12.5.1.4.1.3 and 5.12.5.1.4.2.3, the ISO shall calculate default Energy bid prices utilizing the methodology described below. The Scheduling Coordinator for that Generating Unit shall then be 1) paid the applicable Locational Marginal Price for incremental Dispatch, or 2) charged the applicable Locational Marginal Price for decremental Dispatch.

For Generating Units not subject to the default energy bid prices described in Sections 5.12.5.1.4.1.3 and 5.12.5.1.4.2.3, the ISO shall calculate default Energy bid prices utilizing the following methodology, listed in order of preference subject to the existence of sufficient data:

1. The mean of the Day-Ahead, Hour-Ahead, and real-time Locational Marginal Prices for the units' relevant Location during the lowest-priced 25 percent of the hours that a) the unit was Dispatched or Scheduled, and b) the unit's bid was not mitigated as set forth in this section, over the previous 90 days for peak or off-peak periods, as applicable, adjusted for changes in fuel prices; or

2. A level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the application of the mitigation, and provided the Market Participant has provided sufficient data on a unit's Energy limitations and operating costs (including opportunity cost for Energy limited resources) in accordance with specifications provided by the ISO.

3. If the ISO cannot calculate default bids on the basis of the first and second methods, the ISO shall determine default bids on the basis of:

   - the ISO's estimated costs of that Generating Unit, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or

   - an appropriate average of competitive bids of one or more similar units.

31.2.3.2 Scheduling Requirements

SCs will have the option to submit Balanced Schedules but will not be required to submit Balanced Schedules.

31.2.3.2.1 Load Aggregation

Load will be represented in Congestion Management at a nodal level. For scheduling and settlement, a Scheduling Coordinator may schedule Load at an aggregated level, or alternatively at a nodal level if they are registered to schedule at the location in the ISO Master File. The ISO will maintain on the ISO

Home Page a list of defined Load Zones and sub-zones that comprise standard Load aggregations for this purpose, including the buses within each Load Zone and sub-zone. The ISO shall provide Final Day-Ahead Schedules and Final Hour-Ahead Schedules at the same aggregation level that Scheduling Coordinators specified when they submitted their Schedules. Scheduling Coordinators that established Customer Aggregations in accordance with Section 31.2.3.2.1.2 must schedule using the established Customer Aggregations. Final Schedules for forward market transactions scheduled using a Customer Aggregation shall be settled using that Customer Aggregation. Final Schedules for forward market transactions not scheduled using a Customer Aggregation shall be settled using the Locational Marginal Price for that Load Zone.

Scheduling Coordinators must submit Settlement Quality Meter Data for Loads to the ISO using the same aggregations that were used in scheduling. Deviations between Final Hour-Ahead Schedules and the Settlement Quality Meter Data will be settled at the relevant Dispatch Interval Locational Marginal Price as set forth in Section 31.4.3.2.4 for each Load Zone or Customer Aggregation if established in accordance with Section 31.2.3.2.1.2).

A Scheduling Coordinator may bid Dispatchable Load as an aggregation of Loads that are a) individually under 1 MW, b) served from the same bus, or c) within a single Load Zone but on different buses (e.g., pumping loads within the same watershed or water delivery system) upon ISO agreement on a case-by-case basis. Dispatchable Load must be scheduled using Load Aggregation Points assigned by the ISO. A Dispatchable Load Load Aggregation Point must be within one Load Zone. Dispatchable Load cannot be bid at the level of the PGE3 or SCE1 Load Zones, but must be bid in sub-zones of these Load Zones.

31.2.3.2.1.1 Distribution Factors

The ISO shall publish Load Distribution Factors (LDFs) for Load Zones and Trading Hubs that represent the relative amount of Load at each bus within the Load Zone or Trading Hub, as set forth in

Scheduling Protocol Section 3.2.1. The ISO will use LDFs to allocate aggregated Load to buses. LDFs will also be used as weighting factors to calculate average Load Zone and Trading Hub prices for Settlement of aggregated Loads and Inter-Scheduling Coordinator Trades. The ISO may use updated LDFs that are based on more recent or more detailed information from the Residual Unit Commitment Process. LDFs include the following:

31.2.3.2.1.1.1. Standard Aggregation Scheduling Distribution Factors.

Standard Aggregation Scheduling Distribution Factors are used for scheduling purposes and for settling forward market transactions. They apply to seasonal on and off-peak periods. They are determined by the ISO from actual historical load patterns from State Estimator solutions. If the ISO determines that valid State Estimator solutions are not available for a particular set of conditions, the ISO may use other historical power flow modeling based on WSCC base case to determine these factors. The ISO will update these factors annually, and may update them more frequently if the ISO determines there has been a significant change in underlying conditions. The ISO may adjust Standard Aggregation Scheduling Distribution Factors to account for Demand associated with Customer Aggregations.

31.2.3.2.1.1.2 Standard Aggregation Meter Distribution Factors.

Standard Aggregation Meter Distribution Factors are used for settling real-time transactions and deviations. They are determined by the ISO for each hour using State Estimator solutions. If the ISO determines that valid State Estimator solutions are not available for a particular set of conditions, the ISO may use other means, including using factors from hours with similar system conditions, to determine these factors. The ISO shall adjust Standard Aggregation Meter Distribution Factors to account for Demand associated with Customer Aggregations using Settlement Quality Meter Data.

31.2.3.2.1.1.3 Customer Aggregation Scheduling Distribution Factors

Customer Aggregation Scheduling Distribution Factors are used for scheduling purposes and for settling forward market transactions. They are determined by Load Serving Entities and submitted to the ISO by Scheduling Coordinators.

31.2.3.2.1.1.4 Customer Aggregation Meter Distribution Factors

Customer Aggregation Meter Distribution Factors are used for settling Imbalance Energy. They are established either by meter data or through agreement of the LSE and the UDC.

31.2.3.2.1.2 Customer Aggregation

To reflect the characteristics of Loads that do not vary in proportion to the total load in their Load Zone, Load Serving Entities may elect to schedule Loads using a Customer Aggregation rather than the default Load Zone aggregation. A Customer Aggregation may consist of Load at a single bus or multiple buses, and a Schedule of Demand at a single bus is to be treated as a Customer Aggregation. A Load Serving Entity that elects to schedule Load using a Customer Aggregation must provide Customer Aggregation Scheduling Distribution Factors that reflect its intent in scheduling Energy in forward markets, and either (a) establish a process for calculating Customer Aggregation Meter Distribution Factors corresponding to its Customer Aggregation, or (b) provide Settlement Quality Meter Data at the nodal level. Once a Load Serving Entity establishes a Customer Aggregation, the Scheduling Coordinator representing the Load Serving Entity must use the Customer Aggregation established by that Load Serving Entity for the following twelve months. The Load Serving Entity may update its Customer Aggregation only to add or remove end-use Loads due to customer migration.

To establish a Customer Aggregation, a Load Serving Entity must provide to the ISO the Universal Node Identifier (UNI) of the participating end-use customers in CPUC-jurisdictional service areas, or similar site identifiers in other areas, which may be established by the Local Regulatory Authority but

must, at a minimum, identify the applicable Take Out Point from the ISO Controlled Grid. The ISO may use UNIs to track MWh usage among Load aggregations, recompute LDFs when customers switch between Load aggregations, ensure that all customers are served by one and only one Scheduling Coordinator, and perform other monitoring functions as required. The Loads comprising a Customer Aggregation do not need to be at contiguous buses, but must be within a single UDC's service area. Customer Aggregations must not cross certain boundaries designated by the ISO, including Path 15 and Path 26.

Once a Load Serving Entity has established a Customer Aggregation, the Scheduling Coordinator for the Load Serving Entity shall provide the Customer Aggregation Scheduling Distribution Factors to the ISO. Scheduling Coordinators must submit hourly factors that shall apply as a default if updated factors are not provided through the scheduling process. Updated factors may be submitted as often as once per day. Submitted factors are binding for both Day-Ahead and Hour-Ahead settlements. If no Customer Aggregation Scheduling Distribution Factors have been submitted, the ISO will use the Standard Aggregation Scheduling Distribution Factors determined by the ISO for the Load Zone.

If the Scheduling Coordinator for a Load Serving Entity chooses not to submit Customer Aggregation Meter Distribution Factors, it must submit Settlement Quality Meter Data at the nodal level for Loads in a Customer Aggregation. Because the use of a Customer Aggregation for Settlement will affect the relative weighting of Loads that are served by the host UDC within the Load Zone, and because the UDC will generally have historical data on the Energy usage of the affected Loads, the Load Serving Entity must obtain the UDC's agreement for any proposed Customer Aggregation Meter Distribution Factors. The Load Serving Entity and Scheduling Coordinator must provide accurate Settlement Quality Meter Data, and ensure consistency and auditability by the ISO in any process that uses Customer Aggregation Meter Distribution Factors for determining actual usage for Settlement of the Real Time Market.

31.2.3.2.2. Obligation to Offer Available Capacity

All Participating Generators shall offer to sell in the ISO's Day-Ahead Energy and Ancillary Services markets, Hour-Ahead Energy and Ancillary Services markets, Day-Ahead and Hour-Ahead Residual Unit Commitment Processes, and Real Time Imbalance Energy markets in all hours, all Available Generation from non-hydroelectric Generating Units owned or controlled by the Participating Generators as set forth in this section. Non-hydroelectric Generating Units owned or controlled by the Participating Generators shall be designated as Capacity Resources.

Other Capacity Resources shall offer available capacity in the ISO's Day-Ahead Energy and Ancillary Services markets, Hour-Ahead Energy and Ancillary Services markets, Day-Ahead and Hour-Ahead Residual Unit Commitment Processes, and Real Time Imbalance Energy markets in all hours as required by any agreements they have.

31.2.3.2.2.1. Available Generation

Available Generation is the Generation available for a market if the resource's current status and operational constraints allow the resource to deliver Energy or provide Ancillary Services in accordance with a Schedule that may be established for, or an award that may be made in, that market.

31.2.3.2.2.1.1. Day-Ahead Markets

A 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. 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. System Units

31.2.3.2.3.3.1 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.

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.

31.4.2 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 Actions All 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.

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:

$$PayTI_{ijt} = \sum_{b} INC_{bijt}$$

32.10.2.1.2 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:

$$DEC_{bijt} = adjdec_{bijt} * \Delta dec_{bijt}$$

32.10.2.1.3 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:

$$ChargeTI_{ijt} = \sum_{b} DEC_{bijt}$$

32.10.2.2 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:

$$REDISP_{CONGt} = \sum_{i} PayTI_{ijt} - \sum_{i} ChargeTI_{ijt}$$

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.

32.10.2.3 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:

$$GOP_t = \frac{REDISP_{CONGt}}{\sum_j QCharge_{jt} + \sum_j Export_{jt}}$$

32.10.2.4 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 INCbijt - $

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 adjincbijt - $/MWh

The incremental cost for the rescheduled Generating Unit i or System Resource i or Dispatchable Loadi 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 *incbijt - MW

The amount by which the Generating Unit i or System Resource i or Dispatchable Loadi 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 PayTIjit - $

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 DECbijt - $

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 adjdecbijt - $/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 *decbijt - 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 ChargeTIijt - $

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 Pxt - $/MWh

The zonal Hourly Ex Post Price, for Uninstructed Imbalance Energy, for Dispatch Interval t in Zone x.

32.10.3.10 REDISPCONGt - $

The Dispatch Interval net cost to ISO to redispatch in order to relieve Intra-Zonal Congestion during Dispatch Interval t.

32.10.3.11 GOPt - $/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 GOCjt - $

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 QCHARGEjt – 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 EXPORTjt – 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:

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

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:

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

where:

$UIEC_{i,h,k}$ is the Uninstructed Imbalance Energy charge for resource i during Dispatch Interval k of hour h.

Uninstructed Deviation Penalties may apply in addition to the Uninstructed Imbalance Energy charge as set forth in Section 11.2.4.1.2.

32.12 Transmission Losses.

Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, no allowance shall be made for Transmission Losses (i.e. the Generation Meter Multiplier shall be set at 1.0 for all Scheduling Coordinators) for the Day-Ahead and Hour-Ahead Markets.

32.12.1 Calculation of Transmission Losses for Imbalance Energy Settlements.

The total Demand that may be served by a Generating Unit, in a given hour, taking account of Transmission Losses, is equal to the product of the total Metered Quantity of that Generating Unit in that hour and the Generation Meter Multiplier calculated by the ISO in the hour for that Generator location except in accordance with Section 32.12.3. The Generation Meter Multiplier shall be greater than one (1) where the Generating Unit's contribution to the ISO Controlled Grid reduces Transmission Losses and shall be less than one (1) where the Generating Unit's contribution to the system increases Transmission Losses. All Generating Units supplying Energy to the ISO Controlled Grid at the same electrical bus shall be assigned the same Generation Meter Multiplier.

32.12.2.1 Calculating and Publishing Generation Meter Multipliers.

32.12.2.1.1 By 6:00 p.m. two days preceding a Trading Day, the ISO will calculate, and post on OASIS, an estimated Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. The Generation Meter Multipliers shall be determined utilizing the Power Flow Model based upon the ISO's forecasts of total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO shall continuously update the data to be used in calculating the Generation Meter Multipliers to reflect changes in system conditions on the ISO Controlled Grid, and the ISO shall provide all Scheduling Coordinators with access to such data. The ISO shall not be required to determine new Generation Meter Multipliers for each hour; the ISO will determine the appropriate period for which each set of Generation Meter Multipliers will apply, which period may vary based upon the expected frequency and

magnitude of changes in system conditions on the ISO Controlled Grid.

32.12.2.1.2 The ISO shall publish the GMMs that will be used for Imbalance Energy Settlement (i.e. that reflect the Final Hour-Ahead Schedules for that Settlement Period) no later than one hour following the deadline for submitting bids to the ISO Hour-Ahead Market for that Settlement Period.

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

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

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

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

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

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