function in accordance with the ISO's standards and procedures posted on the ISO Home Page.

ASRP 4.5 Standard for Regulation: Procurement

ASRP 4.5.1 Procurement of Non Self-Provided Regulation

Regulation necessary to meet ISO requirements not met by self-provided Regulation will be procured by the ISO as described in the ISO Tariff.

ASRP 4.5.2 Certification and Testing Requirements

Each Generating Unit and System Unit used to bid Regulation or used to self provide Regulation must have been certified and tested by the ISO using the process defined in Appendix A to this Protocol.

ASRP 4.5.3 [Not Used]

ASRP 4.5.4 [Not Used]

ASRP 5 OPERATING RESERVE STANDARDS

The ISO needs, as a minimum, Operating Reserve, consisting of Spinning Reserve and Non-Spinning Reserve, sufficient to meet WSCC MORC or more stringent criteria as the ISO may determine from time to time.

ASRP 5.1 [Not Used]

ASRP 5.1.1 [Not Used]

ASRP 5.1.2 Providing both Spinning Reserve and Regulation

Spinning Reserve and Regulation may be provided as separate services from the same Generating Unit, provided that the sum of Spinning Reserve and Regulation provided is not greater than the maximum ramp rate of the Generating Unit (MW/minute) times ten.

(e) external imports of System Resources.

ASRP 5.4.2 Non-Spinning Reserve Capability

Each resource providing Non-Spinning Reserve must be capable of converting the full capacity reserved to Energy production within ten minutes after the issue of the Dispatch instruction by the ISO, and of maintaining that output for at least two hours.

ASRP 5.4.3 Availability

Each provider of Non-Spinning Reserve must ensure that its resources scheduled to provide Non-Spinning Reserve are available for Dispatch throughout the Settlement Period for which they have been scheduled.

ASRP 5.5 SC's Obligation for Operating Reserve

ASRP 5.5.1 Obligation for Spinning and Non-Spinning Reserve

Except for the requirement for Non-Spinning Reserve referred to in paragraph ASRP 5.5.2, each Scheduling Coordinator's Operating Reserve obligation shall be pro rata based upon the same proportion as the product of its percentage obligation based on metered output and the sum of its metered Demand and firm exports bears to the total of such products for all Scheduling Coordinators. The Scheduling Coordinator's percentage obligation based on metered output shall be calculated based on WSCC MORC criteria.

ASRP 5.5.2 Additional Non-Spinning Reserve Requirements

Additional Non-Spinning Reserve required pursuant to ASRP 5.2(a) and (b) is the responsibility of the Scheduling Coordinator implementing such Schedules and is in addition to the obligation provided in paragraph ASRP 5.5.1.

ASRP 5.6 Standard for Spinning Reserve: Control

Each provider of Spinning Reserve must be capable of receiving a Dispatch instruction within one minute from the time the ISO Control Center elects to Dispatch the Spinning Reserve resource and must ensure that its resource can be at the Dispatched operating level within ten minutes after issue of the Dispatch instruction.

ASRP 5.7 Standard for Non-Spinning Reserve: Control

Each provider of Non-Spinning Reserve must be capable of receiving a Dispatch instruction within one minute from the time the ISO Control Center elects to Dispatch the Non-Spinning Reserve resource and must ensure that its resource can be at the Dispatched operating level or condition within ten minutes after issue of the Dispatch instruction.

ASRP 5.8 Standard for Operating Reserve: Procurement

ASRP 5.8.1 Procurement of Non Self-Provided Operating Reserve

Operating Reserve necessary to meet ISO requirements not met by self-provided Operating Reserve will be procured by the ISO as described in the ISO Tariff.

ASRP 5.8.2 Procurement Not Limited to ISO Control Area

The ISO will procure Spinning and Non-Spinning Reserves from Generating Units operating within the ISO Control Area and external imports of System Resources.

ASRP 5.8.3 Spinning Reserve Certification and Testing Requirements

Spinning Reserve may only be provided from

(1) Generating Units;

(2) System Resources from external imports; or

(3) System Units;

which have been certified and tested by the ISO using the process defined in Appendix B to this Protocol.

ASRP 5.8.4 Non-Spinning Reserve Certification and Testing Requirements

Non-Spinning Reserve may only be provided from resources including

(1) Loads;

(2) Generating Units;

(3) System Resources from external imports; and

(4) System Units;

which have been certified and tested by the ISO using the process defined in Appendix C to this Protocol.

ASRP 5.8.5 Self Provision of Operating Reserve

Scheduling Coordinators may self provide Spinning and Non-Spinning Reserves from resources outside the ISO Control Area.

ASRP 6 [NOT USED]

ASRP 6.1 [Not Used]

ASRP 6.1.1 [Not Used]

ASRP 6.1.2 [Not Used]

ASRP 6.2 **[NOT USED]**

ASRP 6.2.1 **[Not Used]**

ASRP 6.2.2 **[Not Used]**

ASRP 6.2.3 **[Not Used]**

ASRP 6.3 **[NOT USED]**

ASRP 6.4 **[NOT USED]**

ASRP 6.5 **[NOT USED]**

ASRP 6.5.1 **[NOT USED]**

ASRP 6.5.2 **[NOT USED]**

ASRP 6.5.3 **[NOT USED]**

ASRP 6.5.4 **[NOT USED]**

ASRP 7 **VOLTAGE SUPPORT STANDARDS**

ASRP 7.1 **Standard for Voltage Support: Quantity Needed**

The ISO shall determine on a daily basis for each Settlement Period for each Trading Day the quantity and location of Voltage Support required to maintain voltage levels and reactive margins within WSCC and NERC criteria using a power flow study based on the quantity and location of Demand scheduled in each Settlement Period of the Day-Ahead Market. The ISO shall issue daily voltage schedules (Dispatch instructions) to Generators, Participating TOs and UDCs for each Trading Day, which are required to be maintained for ISO Controlled Grid reliability.

ASRP 7.2 **Standard for Voltage Support: Performance**

ASRP 7.2.1 **Automatic Voltage Regulation Requirement**

A Generating Unit providing Voltage Support must be under the control of generator automatic voltage regulators throughout the time period during which Voltage Support is required to be provided. A Generating Unit may be required to operate underexcited (absorb reactive power) at periods of light system Demand to avoid potential high voltage conditions, or overexcited

ASRP 8.5 Standard for Black Start: Procurement

ASRP 8.5.1 Initial Procurement

Black Start capability will initially be procured by the ISO through individual contracts with Scheduling Coordinators for Reliability Must-Run Units and other Generating Units which have Black Start capability.

ASRP 8.5.2 Certified Generating Units Requirement

Black Start capability may only be provided from Generating Units which have been certified and tested by the ISO using the process defined in Appendix F to this Protocol.

ASRP 9 TESTING FOR STANDARD COMPLIANCE

The ISO shall periodically conduct unannounced tests of resources providing Ancillary Services to confirm the ability of such resources to meet the applicable Ancillary Service standard for performance and control. Scheduling Coordinators for Ancillary Service resources being tested will be compensated for Energy output or Demand reduction provided pursuant to such tests in accordance with the ISO Tariff.

ASRP 9.1 Compliance Testing for Regulation

The ISO may test the capability of any Generating Unit or System Resource providing Regulation by using the ISO EMS to move that Generating Unit's or System Resource's output over the full range of its Regulation capacity within a ten-minute period.

ASRP 9.2 Compliance Testing for Spinning Reserve

The ISO may test the capability of any Generating Unit, System Unit or external import of a System Resource providing Spinning Reserve by issuing unannounced Dispatch Instructions requiring the Generating Unit, System Unit or external import of a System Resource to ramp up to its stated ten minute capability in accordance with the Scheduling Coordinator's Bid. Such tests may not necessarily occur on the hour. The ISO shall measure the response of the Generating Unit, System Unit or external import of a System Resource to determine compliance with its stated capabilities.

ASRP 9.3 Compliance Testing for Non-Spinning Reserve

ASRP 9.3.1 Compliance Testing of a Generating Unit, System Unit or System Resource

The ISO may test the Non-Spinning Reserve capability of a Generating Unit, System Unit or an external import of a System Resource by issuing unannounced Dispatch Instructions requiring the Generating Unit or System Unit to come on line and ramp up or, in the case of a System Resource, to affirmatively respond to real-time interchange schedule adjustment; all in accordance with the Scheduling Coordinator's bid. Such tests may not necessarily occur on the hour. The ISO shall measure the response of the Generating Unit, System Unit or external import of a System Resource to determine compliance with its stated capabilities.

ASRP 9.3.2 Compliance Testing of Dispatchable Load

The ISO may test the Non-Spinning Reserve capability of a Load providing Dispatchable Load by issuing unannounced Dispatch instructions requiring the operator of the Load to report the switchable Demand of that Load actually being served by the operator at the time of the instruction. No Load will be disconnected as part of the test.

ASRP 9.4 [NOT USED]

ASRP 9.4.1 [Not Used]

ASRP 9.4.2 [Not Used]

ASRP 9.5 Compliance Testing for Voltage Support

ASRP 9.5.1 Compliance Testing of a Generating Unit

The ISO may test the Voltage Support capability of a Generating Unit by issuing unannounced Dispatch Instructions requiring the Generating Unit to adjust its power factor outside the specified power factor band of 0.90 lag to 0.95 lead, but within the limits of the Generating Unit capability curve.

ASRP 9.5.2 Compliance Testing of Other Reactive Devices

The ISO may test the Voltage Support capability of other reactive devices (shunt capacitors, static var compensators, synchronous condensers) by issuing unannounced Dispatch Instructions requiring operation of such devices.

ASRP 9.6 Compliance Testing for Black Start

The ISO may test the Black Start capability of a Generating Unit by unannounced tests, which may include issuing Dispatch

Instructions to start and synchronize the resource, testing of all communications circuits, simulating switching needed to connect the Black Start Generating Unit to the transmission system, and testing the features unique to each facility that relate to Black Start service.

ASRP 9.7 Consequences of Failure to Pass Compliance Testing

ASRP 9.7.1 Notification of Compliance Testing Results

If a Generating Unit, Load, or System Resource fails a compliance test, the ISO shall notify the Scheduling Coordinator whose resource was the subject of the test and the Ancillary Service Provider or owner or operator of a System Resource providing Ancillary Services of such failure by any means as soon as reasonably practicable after the completion of the test. In addition, regardless of the outcome of the test, the ISO shall provide the Scheduling Coordinator whose resource was subject to a compliance test written notice of the results of such test. The ISO shall at the same time send a copy of the notice to the Ancillary Service Provider or owner or operator of a System Resource providing Ancillary Services.

ASRP 9.7.2 Penalties for Failure to Pass Compliance Testing

The Scheduling Coordinator whose resource fails a compliance test shall be subject to the financial penalties provided for in the ISO Tariff. In addition, the ISO shall institute the sanctions described in ASRP 11.

ASRP 10 PERFORMANCE AUDITS FOR STANDARD COMPLIANCE

In addition to testing under ASRP 9, the ISO will periodically audit the performance of resources providing Ancillary Services to confirm the ability of such resources to meet the applicable Ancillary Service standard for performance and control.

ASRP 10.1 Performance Audit for Regulation

The ISO will audit the performance of a Generating Unit providing Regulation by monitoring its response to ISO EMS control or, in the case of an external import of a System Resource providing Regulation, by monitoring the dynamic interchange response to ISO EMS control around its Set Point within its rated MW/minute capability over the range of Regulation capacity scheduled for the current Settlement Period.

ASRP 10.2 Performance Audit for Spinning Reserve

The ISO will audit the performance of a Generating Unit or external import of a System Resource providing Spinning Reserve by auditing its response to Dispatch instructions and by analysis of Meter Data associated with the Generating Unit. Such audits may not necessarily occur on the hour. A Generating Unit providing Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move at the MW/minute capability stated in its bid, reach the amount of Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO, and respond to system frequency deviations outside the allowed frequency deadband. An external import of a System Resource providing Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move at the MW/minute capability stated in its bid, reach the amount of Spinning Reserve capacity scheduled for the current settlement Period within ten minutes of issue of the Dispatch instruction by the ISO.

ASRP 10.3 Performance Audit for Non-Spinning Reserve

The ISO will audit the performance of a Generating Unit, Load, or System Resource providing Non-Spinning Reserve by auditing its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. Such audits may not necessarily occur on the hour. A Generating Unit providing Non-Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity under the control of the ISO scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO. An external import of a System Resource providing Non-Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO. A Load providing Non-Spinning Reserve from Curtailable Demand shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruciton by the ISO.

ASRP 10.4 [NOT USED]

ASRP 10.5 Performance Audit for Voltage Support

The ISO will audit the performance of a resource providing Voltage Support by auditing of its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. A resource providing Voltage Support shall be evaluated on its ability to provide reactive support over the stated power factor range of the resource, provide reactive support within the prescribed time periods, and demonstrate the effective function of automatic voltage control equipment for

APPENDIX D

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DEMAND FORECASTING PROTOCOL (DFP)

DFP 1 Objectives, Definitions and Scope

DFP 1.1 Objectives

The objective of the DFP is to set forth procedures for submission of Demand Forecasts which will provide information to the ISO for projecting future Demand requirements to be served by the ISO Controlled Grid. The ISO shall utilize such forecasts to enable it to assess system reliability and carry out its functions under the Scheduling Protocol (SP) and the Outage Coordination Protocol (OCP).

DFP 1.2 Definitions

DFP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix refers to a Section or an Appendix of the ISO Tariff unless otherwise indicated. References to DFP are to this Protocol or to the stated paragraph of this Protocol.

DFP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meaning set opposite them:

"Annual Peak Demand Forecast" means a Demand Forecast of the highest Hourly Demand in any hour in a calendar year, in MW.

"Hourly Demand" means the average of the instantaneous Demand integrated over a single clock hour, in MW.

"ISO Home Page" means the ISO internet home page at http://www.caiso.com/ or such other internet address as the ISO shall publish from time to time.

"Weekly Peak Demand Forecast" means a Demand Forecast of the highest Hourly Demand in any hour in a period beginning at the start of the hour ending 0100 on Sunday and ending at the end of the hour ending 2400 the following Saturday, in MW.

DFP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

DFP 1.3 Scope

DFP 1.3.1 Scope of Application to Parties

The DFP applies to the following entities:

(a) Scheduling Coordinators (SCs);

(b) Utility Distribution Companies (UDCs); and

(c) the ISO.

DFP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

DFP 2 Scheduling Coordinator Demand Forecast Responsibilities

DFP 2.1 Data to be Submitted to the ISO by SCs

At the time specified in DFP 2.3, each SC shall submit to the ISO its Weekly Peak Demand Forecast by Location reflecting (1) the Weekly Peak Demand Forecasts of the UDCs that it proposes to Schedule and (2) any other non-UDC Demand that it proposes to Schedule. All Weekly Peak Demand Forecasts submitted shall include Demand Forecasts for the following 52 weeks.

DFP 2.2 Format of Demand Forecasts

Demand Forecasts must be submitted to the ISO electronically in the format set forth in Schedule 1 of this Protocol.

DFP 2.3 Timing of Submission of Demand Forecasts

The Demand Forecasts described in DFP 2.1 shall be submitted by SCs to the ISO on a monthly basis by noon of the 18th working day of the month.

DFP 2.4 Forecast Standards

DFP 2.4.1 Avoiding Duplication

SCs submitting Demand Forecasts to the ISO shall ensure, to the best of their ability, that any Demand they are forecasting is not included in another SC's Demand Forecasts. To accomplish this, each SC's Demand Forecasts should only reflect those End-Use Customers who they actually have under contract and who have notified their UDC or previous SC of their intention to change to another SC, and which are actually scheduled to convert.

DFP 2.4.2 Required Performance

SCs submitting its Demand Forecasts to the ISO shall take all necessary actions to provide Demand Forecasts that reflect the best judgment of the submitting SC to help avoid potential System Reliability concerns and to enable the ISO to administer a meaningful market for Energy and Ancillary Services. From time to time the ISO may publish information on the accuracy of SC Demand Forecasts.

DFP 2.4.3 Incomplete or Unsuitable Demand Forecasts

If the Demand Forecasts supplied by a SC to the ISO are, in the ISO's opinion, incomplete or otherwise unsuitable for use, or a particular Demand Forecast has not been supplied by a SC to the ISO as required under this Protocol, the ISO will substitute the last valid Demand Forecast received from the SC in replacement for any incomplete, unsuitable or not supplied Demand Forecasts.

DFP 3 UDC Responsibilities

DFP 3.1 Data to be Submitted to the ISO by UDCs

At the time specified in DFP 3.3, each UDC shall submit to the ISO its Weekly Peak Demand Forecasts by Location reflecting the Weekly Peak Demand Forecast for load expected to be served by facilities under the control of the UDC. All Weekly Peak Demand Forecasts submitted shall include Demand Forecasts for the following 52 weeks.

DFP 3.2 Format of Demand Forecasts

Demand Forecasts must be submitted to the ISO electronically in the format set forth in Schedule 2 of this Protocol.

DFP 3.3 Timing of Submission of Demand Forecasts

The Demand Forecasts described in DFP 3.1 shall be submitted by UDC to the ISO on a monthly basis by noon of the twelfth working day of the month.

DFP 3.4 Forecast Standards

DFP 3.4.1 Avoiding Duplication

Each UDC submitting Demand Forecasts to the ISO and its SC shall ensure, to the best of its ability, that any Demand Forecasts that it is submitting to the ISO and its SC are not duplicated in another SC's Demand Forecasts.

DFP 3.4.2 Required Performance

Each UDC submitting its Demand Forecasts to the ISO and its SC shall take all necessary actions to provide Demand Forecasts that reflect the best judgment of the submitting UDC to help avoid potential System Reliability concerns and to enable the ISO to administer a meaningful market for Energy and Ancillary Services. The ISO may publish information on the accuracy of UDC Demand Forecasts from time to time.

DFP 4 ISO Responsibilities

DFP 4.1 Advisory Control Area Demand Forecasts

The ISO will publish on WEnet and supply to the SCs advisory Control Area Demand Forecasts comprised of Hourly Demand Forecasts for each Location for each Settlement Period of the relevant Trading Day. The ISO will publish this information in accordance with the timing requirements set forth in the SP.

DFP 4.2 ISO Demand Forecasts

The ISO shall publish monthly on WEnet the following two (2) Demand Forecasts for the next 52 weeks.

(i) Consolidated SC Forecast. This forecast will be developed by adding together the Weekly Peak Demand Forecasts of the individual SCs.

(ii) Independent ISO Forecast. This forecast will be developed by the ISO.

The ISO may, at its discretion, publish on WEnet additional Demand Forecasts for two or more years following the next year.

DISPATCH PROTOCOL

Table of Contents

DISPATCH PROTOCOL (DP)

DP 1 OBJECTIVES, DEFINITIONS AND SCOPE

DP 1.1 Objectives

The objectives of this Protocol are:

(a) to implement those sections of the ISO Tariff which involve real time and emergency operations;

(b) to describe the real time Dispatch of the Ancillary Services specified in the Ancillary Services Requirements Protocol (ASRP);

(c) to describe the operational activities of the ISO after all commitments have been made in the Hour-Ahead Market as described in the Scheduling Protocol (SP);

(d) to describe the use of Supplemental Energy bids; and

(e) to describe how the ISO will meet the operational requirements of NERC and WSCC guidelines.

DP 1.2 Definitions

DP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to DP are to this Protocol or to the stated paragraph of this Protocol.

DP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Backup ISO Control Center" means the ISO Control Center located in Alhambra, California.

"Control Area Operator" means the person responsible for managing the real time operations of a Control Area.

"Dispatch Instruction" means an operating order that is issued by the ISO to a Participant pertaining to real time operations.

"GCC" means the single point of contact at the grid control center of Southern California Edison Company.

"ISO Home Page" means the ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time.

"Primary ISO Control Center" means the ISO Control Center located in Folsom, California.

"Participant" means any of those entities referred to in DP 1.3.1(a)-(f).

"Power System Stabilizer (PSS)" means an electronic control system applied on a Generating Unit that helps to damp out dynamic oscillations on a power system. The PSS senses Generator variables, such as voltage, current and shaft speed, processes this information and sends control signals to the Generator voltage regulator.

"Qualifying Facility" means a qualifying co-generation or small power production facility recognized by FERC.

"Security Coordinator" means the person responsible for Security Monitoring in real time for the California Area.

"SCED" refers to the Security Constrained Economic Dispatch program described in Section 31.4.3.2.2.1 that is used to economically Dispatch resources in Real-Time.

"TOC" means the single point of contact at the transmission operations center of Pacific Gas & Electric Company.

"Total Transfer Capability (TTC)" means the amount of power that can be transferred over an interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre-contingency and post-contingency system conditions.

"Western Interconnection" means a network of transmission lines embodied within the WSCC Region.

DP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) Time references in this Protocol are references to prevailing Pacific time.

DP 1.3 Scope

DP 1.3.1 Scope of Application to Parties

This Protocol applies to the ISO and to the Participants:

(a) Scheduling Coordinators (SCs);

(b) Utility Distribution Companies (UDCs);

(c) Participating Transmission Owners (PTOs);

(d) Participating Loads;

(e) Participating Generators;

(f) Control Area Operators, to the extent the agreement between the Control Area Operator and the ISO so provides; and

(g) Metered Subsystem (MSS) Operators.

DP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

DP 2 STANDARDS TO BE OBSERVED

DP 2.1 Applicable Reliability Criteria

The ISO shall exercise Operational Control over the ISO Controlled Grid in compliance with all Applicable Reliability Criteria. Applicable Reliability Criteria are defined as the standards established by NERC, WSCC and Local Reliability Criteria and include the requirements of the Nuclear Regulatory Commission (NRC).

DP 2.1.1 WSCC Criteria (Standards)

(a) Western Interconnection

The WSCC set of standards for the Western Interconnection, which are based on the NERC standards. The WSCC further

DP 3 SCHEDULING AND REAL TIME INFORMATION

DP 3.1 Final Schedules

The scheduling process described in the SP will produce for the ISO real time dispatchers for each Settlement Period of the Trading Day a Final Schedule consisting of the combined commitments contained in the Final Day-Ahead Schedules and the Final Hour-Ahead Schedules for the relevant Settlement Period. The Final Schedule will include information with respect to:

(a) Generation schedules;

(b) Demand schedules;

(c) Ancillary Services schedules based on the procurement during the ISO's markets;

(d) Ancillary Services schedules, based on SCs' ISO accepted schedules and forecast load, for self-provided Ancillary Services;

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

(f) Inter-Scheduling Coordinator Energy Trades.

DP 3.2 Supplemental Energy Bids

In addition to the Final Schedules, Supplemental Energy bids will be available to the ISO real time dispatchers, as described in Section 31.4.1.2 of the ISO Tariff for the SCED.

DP 3.3 SC Intertie Schedules

In accordance with the SBP and the SP, SCs shall provide the ISO with Interconnection schedules prepared in accordance with all NERC, WSCC and ISO requirements. The provisions of the SBP and the SP shall apply to real time changes in Interconnection schedules under Existing Contracts.

DP 3.4 Information to be Supplied by SCs

DP 3.4.1 SC Dispatch

Each SC shall be responsible for the scheduling and Dispatch of Generation and Demand in accordance with its Final Schedule.

DP 3.4.2 Generator or Interconnection Schedule Change

Each SC shall keep the ISO apprised of any change or potential change in the current status of all Generating Units, Interconnection schedules and Inter-Scheduling Coordinator Energy Trades. This will include any changes in Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of a Generating Unit. Each SC shall immediately pass to the ISO any information which it receives from a Generator which the Generator provides to the SC pursuant to DP 3.7. Each SC shall immediately pass to the ISO any information it receives from a MSS Operator.

DP 3.4.3 Verbal Communication with Generators

Normal verbal communication of Dispatch Instructions between the ISO and Generators will be via the relevant SC. Each SC must immediately pass on to the Generator concerned any verbal communication for the Generator which it receives from the ISO. If the ISO considers that there has been a failure at a particular point in time or inadequate response over a particular period of time by the Generating Units to the Dispatch Instruction, the ISO will notify the relevant SC. The ISO may, with the prior permissions of the Scheduling Coordinator concerned, communicate with and give Dispatch Instructions to the operators of Generating Units and Loads directly without having to communicate through their appointed Scheduling Coordinator. In situations of deteriorating system conditions or emergency, the ISO reserves the right to communicate directly with the Generator(s) as required to ensure System Reliability.

DP 3.4.4 Consequences of a Failure to Respond or Inadequate Response

The ISO may apply penalties (including the Uninstructed Deviation Penalties set forth in Section 11.2.4.1.2), fines, economic consequences or the sanctions referred to in DP 9.5.2 for any failure or inadequate response under DP 3.4.3 to the SC representing the Generator responsible for such failure or inadequate response (which may be appropriately weighted to reflect its seriousness) subject to any necessary FERC approval.

DP 3.5 Information to be Supplied by UDCs

DP 3.5.1 UDC Status Change

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

DP 3.5.2 UDC Outage Scheduling

Each UDC shall schedule all equipment Outages (or Outages of other equipment that could affect the ISO Controlled Grid) at the point of its SC any actual or potential concerns or problems that it may have with respect to Generating Unit direct digital control equipment, Generating Unit voltage control equipment, or any other equipment that may impact the reliable operation of the ISO Controlled Grid.

DP 3.7.2 Generator Schedules

In the event that a Generator cannot meet its Generation schedule, whether due to a Generating Unit trip or the loss of a piece of equipment causing a reduction in capacity or output, the Generator shall notify the ISO, through its SC at once. If a Generator will not be able to meet a time commitment or requires the cancellation of a Generating Unit start up, it shall notify the ISO, through its SC at once.

DP 3.8 Information to be Supplied by Control Area Operators

DP 3.8.1 System Status Change

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

DP 3.8.2 Scheduling Procedure

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

DP 3.8.3 Data Exchange

The ISO and each adjacent Control Area Operator shall exchange MW, MVar, terminal and bus voltage data with each other on a four second update basis. MWh data for the previous hour shall be exchanged once per hour. All MW and MWh data for both the ISO Control Area and the adjacent Control Areas must originate from the same metering equipment.

(g) time of notification of the Dispatch Instruction; and

(h) any other information which the ISO considers relevant.

DP 4.4 Acknowledgement of Dispatch Instructions

The recipient of a Dispatch Instruction shall confirm the Dispatch Instruction. Dispatch Instructions communicated by the ISO either electronically or by fax shall be confirmed electronically in accordance with ISO procedures. Dispatch instructions communicated verbally shall be confirmed by repeating the Dispatch instructions to the ISO. Dispatch Instructions of Imbalance Energy will be deemed delivered and settled in accordance with Sections 31.4.3.3 and 31.4.3.4 of the ISO Tariff.

DP 5 ISO FACILITIES AND EQUIPMENT

DP 5.1 ISO Facility and Equipment Outages

The ISO has installed redundant control centers, communication systems and computer systems. Most, but not necessarily all, equipment problems or failures should be transparent to Participants. This DP 5 addresses some situations when Participants could be affected, but it is impossible to identify and plan for every type of equipment problem or failure. Real time situations will be handled by the real time ISO dispatchers. The ISO control room in Folsom is the Primary ISO Control Center and the ISO control room in Alhambra is the Backup ISO Control Center.

DP 5.2 WEnet Unavailable

DP 5.2.1 Unavailable Critical Functions of WEnet

During a total disruption of the WEnet several critical functions of the ISO will not be available including:

(a) the Scheduling Infrastructure (SI) computer will not be able to communicate with SCs to receive any type of updated Schedule information;

(b) the SI computer will not be able to communicate Final Energy, Ancillary Services and Congestion information to the SCs; and

(c) the ISO will not be able to communicate general information, including emergency information, to any Participants.

DP 5.2.2 Communications during WEnet Unavailability

During any period of WEnet unavailability, the ISO shall:

(a) make all reasonable efforts to keep Participants aware of current ISO Controlled Grid status using voice communications;

(b) use the most recent set of final Energy Schedules for each SC for the current and all future Settlement Periods and/or Trading Days until the WEnet is restored; and

(c) attempt to take critical Schedule changes from SCs via voice communications as time and manpower allows.

DP 5.3 Primary ISO Control Center – Loss of all Voice Communications

DP 5.3.1 Notification of Loss of Voice Communication

In the event of loss of all voice communication at the Primary ISO Control Center, the Primary ISO Control Center will use alternate communications to notify the Backup ISO Control Center of the loss of voice communications. The Backup ISO Control Center will notify Participants via OASIS or other means. Additional voice notifications will be made as time permits.

DP 5.3.2 Notification of Restoration of Voice communication

Once voice communications have been restored to the Primary ISO Control Center, the ISO will notify Participants via OASIS or other means.

DP 5.4 Primary ISO Control Center – Control Center Completely Unavailable

DP 5.4.1 Notification of Loss of Primary ISO Control Center

In the event that the Primary ISO Control Center becomes completely unavailable, the Primary ISO Control Center will use alternate communications to notify the Backup ISO Control Center that the Primary ISO Control Center is unavailable. The Backup ISO Control Center will notify Participants via OASIS or other means. Additional voice notifications will be made as time permits.

DP 5.4.2 Backup ISO Control Center Response

The Backup ISO Control Center will notify Participants via OASIS or other means that all computer systems are functioning normally (if such is the case) and take complete control of the ISO Controlled Grid. The Backup ISO Control Center will notify the TOC by direct voice communication of the situation.

DP 5.4.3 Notification of Restoration of Primary ISO Control Center

Once the Primary ISO Control Center is again available, all functions will be transferred back, and the Primary ISO Control Center will notify all Participants via OASIS.

DP 5.5 Primary ISO Control Center - ISO Energy Management System (EMS) Unavailable

DP 5.5.1 Notification of Loss of EMS

Should an outage occur to the redundant EMS computer systems in the Primary ISO Control Center, an auto transfer should occur to transfer EMS operation to the redundant EMS back up computers at the Backup

ISO Control Center. Due to the severity of a total ISO EMS computer outage, the Primary ISO Control Center will notify Participants via OASIS or other means that the Primary ISO Control Center EMS computer is unavailable and that EMS control has been transferred to the Backup ISO Control Center.

DP 5.5.2 Notification of Restoration of EMS

When the Primary ISO Control Center EMS computer is restored, the Backup ISO Control Center will initiate a transfer back of the EMS system to the Primary ISO Control Center. The Primary ISO Control Center will notify Participants via OASIS or other means of the restored EMS computer system status.

DP 5.6 Backup ISO Control Center – Loss of all Voice Communications

DP 5.6.1 Notification of Loss of Voice Communication

In the event of a loss of all voice communications at the Backup ISO Control Center, the Backup ISO Control Center will use alternate communications to notify the Primary ISO Control Center of the loss of voice communications. The Primary ISO Control Center will notify Participants via OASIS or other means of the situation. Additional voice notifications will be made as time permits.

DP 5.6.2 Notification of Restoration of Voice Communication

Once voice communications have been restored to the Backup ISO Control Center, the Primary ISO Control Center will notify Participants via OASIS or other means.

DP 5.7 Backup ISO Control Center – Control Center Completely Unavailable

DP 5.7.1 Notification of Loss of Backup ISO Control Center

In the event that the Backup ISO Control Center becomes completely unavailable, the Backup ISO Control Center will use alternate communications to notify the Primary ISO Control Center that the Backup ISO Control Center is unavailable. The Primary ISO Control Center will notify Participants via OASIS or other means. Additional voice notifications will be made as time permits.

DP 5.7.2 Primary ISO Control Center Response

The Primary ISO Control Center will notify Participants via OASIS or other means that all computer systems are functioning normally (if such is the case) and take complete control of the ISO Controlled Grid. The Primary ISO Control Center will notify the SCE GCC by direct voice communications of the situation.

DP 5.7.3 Notification of Restoration of Backup ISO Control Center

Once the Backup ISO Control Center is again available all functions will be transferred back, and the Backup ISO Control Center will notify all Participants via OASIS.

DP 5.8 Use of IOUs' Energy Control Center Computers

The ISO and the IOUs will comply with the procedures for the utilization by the ISO of the IOUs' Energy control center computers when developed. The ISO will post such procedures on the ISO Home Page when agreed.

DP 6 ROUTINE OPERATION OF THE ISO CONTROLLED GRID

DP 6.1 Overview/Responsibility

The ISO shall operate the ISO Controlled Grid in accordance with the standards described in DP 2 and within the limit of all applicable nomograms and established operating limits and procedures.

DP 6.2 ISO Controlled Facilities

DP 6.2.1 General

The ISO shall have Operational Control of all transmission lines and associated station equipment that have been transferred to the ISO Controlled Grid from the PTOs as listed in the ISO Register.

DP 6.2.2 Primary ISO Control Center

The Primary ISO Control Center shall have Operational Control over:

(a) all transmission lines greater than 230kV and associated station equipment on the ISO Controlled Grid;

(b) all Interconnections; and

(c) all 230 kV and lower voltage transmission lines and associated station equipment identified in the ISO Register as that portion of the ISO Controlled Grid located in the PG&E Service Area.

DP 6.2.3 Backup ISO Control Center

The Backup ISO Control Center shall have Operational Control over all 230 kV and lower voltage transmission lines and associated station equipment identified in the ISO Register as that portion of the ISO Controlled Grid located in the SCE and SDGE Service Areas.

DP 6.3 Clearing Equipment for Work

The clearance procedures of the ISO and the relevant UDC and PTO must be adhered to by all parties, to ensure the safety of all personnel working on ISO Controlled Grid transmission lines and equipment. In accordance with the OCP, no work shall start on any equipment or line which is under the Operational Control of the ISO unless final approval has first been obtained from the appropriate ISO Control Center. Prior

DP 6.9 Security Monitoring

The ISO shall be the Regional Reliability Coordinator for the California Mexico Reliability Center. As Regional Reliability Coordinator, the ISO, in conjunction with the other WSCC Regional Reliability Coordinators, will be responsible for the stable and reliable operation of the Western Interconnection in accordance with the WSCC Regional Security Plan.

DP 6.9.1 Security Coordinator

As Regional Reliability Coordinator, the ISO may direct activities as appropriate to curtail Schedules, Dispatch Generation or impose transfer limitations as necessary to relieve grid Congestion, mitigate potential overloads or eliminate operation outside of existing nomogram criteria.

DP 6.9.2 Authority of WSCC Regional Reliability Coordinators

(a) The Regional Reliability Coordinator has the final authority to direct operations before, during and after problems or disturbances that have regional impacts. The WSCC security monitoring plans include collaboration with sub-regional Regional Reliability Coordinators and control area operators to determine actions for anticipated problems. If there is insufficient time, or mutual concurrence is not reached, the Regional Reliability Coordinator is authorized to direct actions and the control area operators must comply.

(b) In the event of any situation occurring which is outside those problems already identified in the list of known problems, the Regional Reliability Coordinator shall have the responsibility and authority to implement whatever measures are necessary to maintain system reliability. Those actions include but are not limited to; interchange curtailment, generation dispatch adjustment (real power, reactive power and voltage), transmission configuration adjustments, special protection activation, load curtailment and any other action deemed necessary to maintain system reliability.

(c) The Regional Reliability Coordinator shall also have the responsibility and authority to take action in its sub-region for problems in another sub-region that it may help resolve. This must be accomplished at the request of and in coordination with the Regional Reliability Coordinators of the other sub-regions.

DP 7 REAL TIME OPERATIONAL ACTIVITIES – THE HOUR PRIOR TO THE SETTLEMENT PERIOD

DP 7.1 Schedule Confirmation

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

(a) verify that there are sufficient Ancillary Services scheduled as needed to meet the ISO Ancillary Service requirements. The ISO will procure additional Ancillary Services if insufficient resources are scheduled;

(b) review the available Energy bids that will be used in the Real-Time Market;

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

(d) perform the Hourly Pre-Dispatch process in accordance with Section 31.4.2.

DP 7.2 Confirm Interchange Transaction Schedules (ITSs)

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

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

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

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

DP 7.3 [Not Used]

DP 7.4 [Not Used]

DP 7.5 Withdrawal of Supplemental Energy Bids

Scheduling Coordinators may contact the ISO to withdraw Bids from System Resources (unless such bids are from Capacity Resources) at any time before they are Dispatched by the ISO for a particular Settlement Period, however, once these Bids are Dispatched by the ISO they cannot be withdrawn.

DP 8 REAL TIME OPERATIONAL ACTIVITIES – THE SETTLEMENT PERIOD

DP 8.1 Settlement Period

DP 8.1.1 Responsibility of the ISO in Real Time Dispatch

During real time Dispatch, the ISO will be responsible for dispatching Generating Units, System Units, Dispatchable Load and System Resources to meet real time imbalances between actual and scheduled Demand and Generation and to relieve Congestion, if necessary, to ensure System Reliability and to maintain Applicable Reliability Criteria.

DP 8.1.2 Utilization of Security Constrained Economic Dispatch

To achieve this, the ISO Control Center will utilize a Security Constrained Economic Dispatch ("SCED") program pursuant to Section 31.4.3.2.2.1 to determine the recommended Dispatch instructions.

DP 8.1.3 Exceptional Dispatches

In addition to those resources dispatched by the SCED the ISO may dispatch additional resources as needed to perform Ancillary Services testing, to address Overgeneration, Contingencies, Loop Flows, Nomogram violations, emergency conditions, or any other threats to System Reliability that cannot be addressed by SCED due to modeling limitations, insufficient or inaccurate data input in accordance to Section 31.4.3.2.5.

DP 8.2 Generating Units, Loads and Interconnection Schedules Dispatched for Congestion

If there is Congestion in real time, the ISO will use recommended Dispatch Instructions produced by the SCED to alleviate the Congestion as described in DP 8.3. The ISO will use any unused Energy Bids that have been carried forward from the Hour-Ahead Market as described in Section 31.4.1.

DP 8.3 Congestion Management

The ISO will utilize a full network model within the SCED that reflects all real-time network configurations and constraints as determined by the latest State Estimator solution as described in Section 31.4.3.2.1. SCED will be used to economically Dispatch Generating Units, Dispatchable Load, System Units and System Resources to effectively meet Imbalance Energy requirements and eliminate Price Overlap in real-time subject to network constraints that actually exist and to prevent network constraints from developing.

DP 8.3.1 [Not Used]

DP 8.3.2 [Not Used]

DP 8.3.3 [Not Used]

DP 8.4 [Not Used]

DP 8.5 Additional Congestion Relief

If ISO is unable to resolve Congestion utilizing submitted Energy Bids, the ISO will insert default Energy Bids for those resources capable of responding to real-time Dispatch instructions into the SCED to manage the Congestion as described in Section 31.4.3.2.3.2. Final Schedules which rely on Existing Contracts will be adjusted in real time by allocating transmission capacity in accordance with the operating instructions submitted under SBP 3.3. With respect to facilities financed with Local Furnishing Bonds the ISO shall adjust Final Schedules in real time in a fashion consistent with Section 2.1.3 and 7.1.6.3 of the ISO Tariff, Appendix B of the TCA, and Operating Procedures governing the use of such facilities.

DP 8.6 Real Time Dispatch Application

DP 8.6.1 Real Time Dispatch

During real time, the ISO shall dispatch Generating Units, System Units, Dispatchable Loads and System Resources to meet imbalances between actual and scheduled Demand and Generation.

In addition, the ISO shall procure additional Ancillary Services as set forth in Section 31.4.4 if Ancillary Services procured in advance are used to provide Imbalance Energy, and such depletion needs to be recovered to meet System Reliability and contingency requirements.

DP 8.6.2 Utilization of the SCED

The ISO will use the recommended Dispatch Instructions as produced by BEEP, to procure balancing Energy for:

(a) satisfying needs for Imbalance Energy;

(b) mitigating Congestion;

(c) allowing resources providing Regulation service to return to the Dispatch Operating Point of their regulating ranges;

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

(e) procuring additional real-time Voltage Support required from resources beyond the power factor range set forth in Section 2.5.3.4.

(f) [Not Used]

DP 8.6.3 Basis for Real Time Dispatch

The ISO shall base real time Dispatch of Generating Units, System Units, Dispatchable Load and System Resources on the following principles:

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

(b) in each Dispatch Interval, following the loss of a resource and once ACE has returned to zero, the ISO shall determine if the Regulation Generating Units and System Resources are operating at a point away from their Set Point. The ISO shall then adjust the output of Generating Units, System Units, Dispatchable Load, and System Resources (either providing Spinning Reserve, Non-Spinning Reserve, or Real-Time Imbalance Energy) to return the Regulation Generating Units and System Resources to their Set Points to restore their full regulating margin;

(c) in each Dispatch Interval, the ISO shall dispatch Generating Units, System Units, Dispatchable Load and System Resources to meet its Imbalance Energy requirements and eliminate any Price Overlap between decremental and incremental Energy Bids at least cost;

(d) [Not Used]

(e) the ISO shall not discriminate between Generating Units, System Units, Dispatchable Load and System Resources other than based on Energy bids, and the effectiveness (location) of the resource concerned to respond to the fluctuation in Demand or Generation, subject to network and ramp rate constraints;

(f) Generating Units, System Units, Dispatchable Load or System Resources shall be dispatched during the Settlement Period only until the next variation in Generation or Demand or the end of the Settlement Period, whichever is sooner. In dispatching such resources, the ISO is not making any commitment beyond the Settlement Period, as to the duration of their operation, nor the level of their output or Demand;

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

(h) [Not Used]

[Page Not Used]

(i) The ramp rate as identified in the ISO Master File of a resource will be considered by the SCED program in determining the amount of Instructed Imbalance Energy Dispatched and thereby deemed delivered during the Dispatch Interval, and such consideration may result in Instructed Imbalance Energy in Dispatch Intervals subsequent to the Dispatch Interval to which the Dispatch Instruction applies;

(j) The Hourly Pre-Dispatch shall take place no later than 30 minutes prior to the Settlement Period. The ISO shall Dispatch resources at least cost to supply Imbalance Energy or Dispatch demand on an hourly basis to meet some of the Settlement Period's forecasted Imbalance Energy requirement plus Ramping Energy requirements for the transition into the Settlement Period's scheduled Generation and interchange. The ISO shall determine the Hourly Pre-Dispatch Energy prior to the beginning of the Settlement Period to: i) ensure resources that require advance notice are provided such notice prior to requiring their energy, ii) instruct System Resources far enough in advance to allow the interchange bid to be arranged with external control areas and iii) allow resources that have been dispatched in the previous Settlement Period and are determined to be economic in the upcoming Settlement Period to maintain their instructed level. The Hourly Pre-Dispatch optimization methodology is described in Appendix A to this Protocol.

(k) The ISO may notify resources to be Dispatched within the Settlement Period in advance of the Settlement Period to i) allow those resources previously Dispatched to maintain their instructed level, or ii) provide sufficient notice to resources providing Supplemental Energy with start-up times longer than ten minutes.

DP 8.7 Ancillary Services Requirements

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

DP 8.7.1 Regulation

(a) Regulation provided from Generating Units or System Resources must meet the standards specified in the ASRP;

(b) the ISO will dispatch Regulation as determined by ISO EMS AGC program to respond to Area Control Error (ACE) on a continual basis to maintain system frequency and net scheduled control area interchange;

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

(d) when scheduled Operating Reserve is used for restoration of Regulation reserve, the ISO shall arrange for the replacement of that Operating Reserve (see DP 8.7.4);

DP 8.7.2 Operating Reserve

(a) Spinning Reserve:

(i) Spinning Reserve provided from Generating Units and Interconnection schedules must meet the standards specified in the ASRP;

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

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

(iv) the ISO will dispatch Spinning Reserve as determined by SCED;

(b) Non-Spinning Reserve:

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

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

(iii) the ISO will dispatch Non-Spinning Reserve as determined by SCED; and

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

DP 8.7.3 [Not Used]

DP 8.7.4 Replacement of Operating Reserve

(a) [Not Used]

(b) if Operating Reserve is used to meet Imbalance Energy requirements, the ISO may replace such Operating Reserve by dispatching additional Imbalance Energy available from Supplemental Energy bids;

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

(d) where the ISO elects to rely upon Supplemental Energy bids, the ISO shall select the resources at least cost and to eliminate any Price Overlap between incremental and decremental Supplemental Energy Bids subject to network constraints

(e) [Not Used];

DP 8.7.5 Voltage Support

(a) Voltage Support provided from Generating Units shall meet the standards specified in the ASRP;

(b) the ISO may Dispatch Generating Units to increase or decrease MVar output within the power factor limits of 0.9 lagging to 0.95 leading (or within other limits specified by the ISO in any exemption granted pursuant to Section 2.5.3.4 of the ISO Tariff) at no cost to the ISO when required for System Reliability;

(c) may Dispatch each Generating Unit to increase or decrease MVar output outside of established power factor limits, but within the range of the Generating Unit's capability curve, at a price calculated in accordance with Section 2.5.18 of the ISO Tariff;

(d) If Voltage Support is required in addition to that provided pursuant to DP 8.7.5 (b) and (c), the ISO will reduce output of Participating Generators certified in accordance with the ASRP as determined by SCED. The ISO will select Participating Generators in the vicinity where such additional Voltage Support is required; and

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

DP 8.7.6 Black Start

(a) Black Start shall meet the standards specified for Black Start in the ASRP; and

(b) the ISO will dispatch Black Start as required in accordance with the applicable Black Start Agreement.

DP 8.8 Real Time Management of Overgeneration Conditions

In the event that Overgeneration conditions occur during real time, the ISO will direct the SCs to take the steps described in Section 2.3.4 of the ISO Tariff and SCs shall implement ISO directions without delay.

DP 9 DISPATCH INSTRUCTIONS

DP 9.1 ISO Dispatch Authority

DP 9.1.1 Range of ISO Authority

The ISO has full authority to:

(a) direct the physical operation of the ISO Controlled Grid, including (without limitation) circuit breakers, switches, voltage control equipment, protective relays, metering and Load Shedding equipment;

(b) commit Reliability Must-Run Generation, except that the ISO shall only commit Reliability Must-Run Generation for Ancillary Services capacity according to Section 5.2 of the Tariff;

(c) order a change in operating status of voltage control equipment;

(d) take required action to prevent against uncontrolled losses of load or Generation;

(e) control the output of Generating Units and Interconnection schedules scheduled to provide Ancillary Services or offering Supplemental Energy;

(f) dispatch Dispatchable Load which has been scheduled to provide Non-Spinning Reserve; and

(g) require the operation of resources which are at the ISO's disposal in a System Emergency, as described in DP 10.

DP 9.1.2 Exercise of the ISO's Authority

The ISO will exercise its authority under DP 9.1.1 by issuing Dispatch Instructions to the relevant Participants using the relevant communications method described in DP 4.

DP 9.2 Participant Responsibilities

DP 9.2.1 Compliance with Dispatch Instructions

All Participants within the ISO Control Area and all System Resources shall comply fully and promptly with the ISO's Dispatch Instructions unless such operation would impair public health or safety. In this regard, Dispatch Instructions for Energy by Generating Units, System Resources, System Units and Dispatchable Load, are deemed to be operating orders pursuant to Section 2.3.1.2.1. As such these Dispatch Instructions are binding obligations and a resource so Dispatched cannot be made unavailable or otherwise fail to respond to ISO operating orders except for conditions beyond the control of the resource owner. Shedding Load for a System Emergency does not constitute impairment to public health or safety.

DP 9.2.2 Notification of Non-Compliance with a Dispatch Instruction

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

DP 9.3 Dispatch Instructions for Generating Units and Curtailable Dispatchable Load

The ISO may issue Dispatch Instructions covering:

(a) Ancillary Services;

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

(i) managing Congestion; or

(ii) replacing of an Ancillary Service;

(c) agency operation of Generating Units, Dispatchable Load or System Resources, for example:

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

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

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

(d) the operation of voltage control equipment applied on Generating Units as described in the ASRP.

DP 9.4 Response Required by Generators to ISO Dispatch Instructions

DP 9.4.1 Action Required by Generators

Generators must:

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

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

(c) meet the ramp rates required by ASRP for the Ancillary Service concerned;

(d) respond to Dispatch Instructions for Ancillary Services within the time periods required by ASRP except in a System Emergency, when DP 10 will apply; and (in the case of Generating Units providing Regulation) respond to electronic signals from the EMS; and

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

DP 9.4.2 Qualifying Facilities

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

DP 9.5 Failure to Comply with Dispatch Instructions

DP 9.5.1 Obligation to Comply

All entities providing Ancillary Services (whether self-provided or procured by the ISO) or whose Supplemental Energy bids have been accepted by the ISO shall be obligated to respond to the ISO's Dispatch Instructions in accordance with their terms. If a dispatched Generating Unit, System Unit, Dispatchable Load or System Resource fails to respond to a Dispatch Instruction in accordance with its terms, that entity:

(a) shall be declared and labeled as non-conforming to the Dispatch Instruction;

(b) cannot set the Dispatch Interval LMP.

DP 9.5.2 Sanctions

The ISO will develop additional mechanisms to deter Generating Units and Loads in other Control Areas from failing to respond at a particular time or adequately respond over a particular period of time to a Dispatch Instruction or failing to perform according to Dispatch Instructions, for example, reduction in payments to SCs or suspension of the SC's Ancillary Services certificate for the Generating Unit, Dispatchable Load or System Resource concerned.

DP 10 EMERGENCY OPERATIONS

DP 10.1 Notifications by ISO

The ISO will provide the following notifications to Participants to communicate unusual system conditions or emergencies.

DP 10.1.1 System alert

ISO will give a system alert notice when the operating requirements of the ISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation or loss of transmission capacity that has curtailed imports into the ISO Control Area, or if the Hour-Ahead Market is short on scheduled Energy and Ancillary Services for the ISO Control Area.

DP 10.1.2 System warning

The ISO will give a system warning notice when the operating requirements for the ISO Controlled Grid are not being met in the Hour-Ahead Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve, and Supplemental Energy available to the ISO is not acceptable for the Applicable Reliability Criteria. This system warning notice will notify Participants that the ISO will, acting in accordance with Good Utility Practice, take such steps as it considers necessary to ensure compliance with Applicable Reliability Criteria, including the negotiation of Generation through processes other than competitive bids.

DP 10.1.3 System Emergency

When, in the judgement of the ISO, the System Reliability of the ISO Controlled Grid is in danger of instability, voltage collapse or under-frequency caused by transmission or Generation trouble in the ISO Control Area, or events outside of the ISO Control Area that could result in a cascade of events throughout the WSCC grid, the ISO will declare a System Emergency. This declaration may include a notice to suspend the Day-Ahead, Hour-Ahead and Real Time Markets, authorize full use of Black Start Generation, initiate full control of manual Load Shedding, authorize the curtailment of Dispatchable Load (even though not scheduled as an Ancillary Service). The ISO will reduce the System Emergency declaration to a lower alert status when it is satisfied, after conferring with Security Coordinators within the WSCC that the major contributing factors have been corrected, all involuntarily interrupted Demand is back in service (except interrupted Dispatchable Load selected as an Ancillary Service). This reduction in alert status will reinstate the competitive markets if they have been suspended.

DP 10.2 Management of System Emergencies

DP 10.2.1 Declaration of System Emergencies

The ISO shall, when it determines that a System Emergency exists, declare the existence of such System Emergency. A declaration of System Emergency by the ISO shall be binding on all Participants until the ISO announces that the System Emergency no longer exists.

DP 10.2.2 Emergency Procedures

In the event of a System Emergency, the ISO shall:

(a) take action as it considers necessary to preserve or restore stable operation of the ISO Controlled Grid;

(b) act in accordance with Good Utility Practice to preserve or restore reliable, safe and efficient service as quickly as reasonably practicable;

(c) keep adjacent Control Area Operators informed as to the nature and extent of the System Emergency in accordance with WSCC procedures; and

(d) where practicable, keep the Participants within the ISO Control Area informed.

DP 10.2.3 [Not Used]

DP 10.2.4 Emergency Guidelines

The ISO shall issue procedures for all Participants to follow during a System Emergency. These guidelines shall be consistent with the specific obligations of SCs and Participants referred to in DP 10.2.8, and DP 10.4

DP 10.2.5 Implementation of Dispatch Instructions

All Participants shall respond to ISO Dispatch Instructions with an immediate response during System Emergencies.

DP 10.2.6 Periodic Tests of Emergency Procedures

The ISO shall develop and administer periodic unannounced tests of System Emergency procedures. The purpose of such tests will be to ensure that the Participants are capable of responding to actual System Emergencies.

DP 10.2.7 Prioritized Schedule for Shedding and Restoring Load

The ISO shall, in consultation with Participants, develop a prioritized schedule for Load Shedding if a System Emergency requires such action. Such a schedule will include a prioritization of restoring Load if multiple Participants are affected.

DP 10.2.8 Obligations of Participating Generators Relating to System Emergencies

All Generating Units are subject to control by the ISO during a System Emergency. The ISO shall have the authority to:

(a) instruct a Participating Generator to shut down any of its Generating Units which the Participating Generator does not require, or start any of its Generating Units that can be started in time to assist with the System Emergency;

(b) instruct a Participating Generator to increase or curtail the output of any of its Generating Units; and

(c) UDC Disconnect Load

The ISO shall have the authority to direct a UDC to disconnect Load from the ISO Controlled Grid if necessary to avoid an anticipated System Emergency or to regain Operational Control over the ISO Controlled Grid during an actual System Emergency.

(d) UDC Load Curtailment Programs

As an additional resource for maintaining reliability and managing System Emergencies, the ISO may notify UDCs when the conditions exist which require the UDCs to implement their Load curtailment programs. The UDCs will exercise their best efforts, including seeking any necessary regulatory approvals, to enable the ISO to rely on their curtailment rights at specified levels of Operating Reserve.

DP 10.4.2 Load Curtailment

A SC may specify that Load will be reduced at Locational Marginal 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 Dispatchable Load to assume response capability for managing System Emergencies. The ISO may establish standards for automatic communication of curtailment instructions to implement Load curtailment as a condition for accepting any offered Load curtailment as an Ancillary Service.

DP 11 ALGORITHMS TO BE USED

The ISO shall develop dispatch algorithms for use by the ISO for dispatching Generating Units and Dispatchable Load in accordance with the ISO Tariff.

DP 12 INFORMATION MANAGEMENT

The ISO shall provide all Participants with non-discriminatory access to information concerning the status of the ISO Controlled Grid by posting such information on the OASIS, or other similar computer communications device, or by telephone or facsimile in the event of computer systems failure.

DP 13 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

APPENDIX A

ISO Market Monitoring Plan

Market Mitigation Measures

1 PURPOSE AND OBJECTIVES

1.1 These ISO market power mitigation measures ("Mitigation Measures") are intended to provide the means for the ISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the ISO Markets and Residual Unit Commitment Processes while avoiding unnecessary interference with competitive price signals. These Mitigation Measures are intended to minimize interference with an open and competitive market, and thus to permit, to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the Mitigation Measures authorize the mitigation only of specific conduct that exceeds well-defined thresholds specified below.

1.1.1 In addition, the ISO shall monitor the markets it administers for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the ISO. If the ISO identifies any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified below, it shall make a filing under Section 205 of the Federal Power Act, 16 U.S.C. § 824d, with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the ISO's justification for imposing that mitigation measure.

1.2 CONDUCT WARRANTING MITIGATION

2.1 Definitions

The following definitions are applicable to this Appendix A:

"Economic Market Clearing Prices" are the market clearing prices for a particular resource at the location of that particular resource at the time the resource was either Scheduled or was Dispatched by the ISO. Economic Market Clearing Prices may originate from the Day-Ahead Energy Market, the Hour-Ahead Energy Market, or ISO Real-time Imbalance Energy Market. The Economic Market Clearing Price for the ISO Real Time Imbalance Energy Market shall be the Dispatch Interval Locational Marginal Price, unless the resource cannot change output level within the hour (i.e., the resource is not amenable to intra-hour real-time dispatch instructions), or it is a System Resource. Economic Market Clearing Prices for the ISO Real Time Imbalance Energy Market for resources that cannot change output level within one Dispatch Interval and System Resources shall be the simple average of the six Dispatch Interval Locational Marginal Prices for each hour.

"Electric Facility" shall mean an electric resource, including a Generating Unit, System Unit, Participating Load or a System Resource.

2.2 Conduct Subject to Mitigation

Mitigation Measures may be applied: (i) to the bidding, scheduling, or operation of an "Electric Facility"; or (ii) as specified in section 2.4 below.

2.3 Conditions for the Imposition of Mitigation Measures

2.3.1 In general, the ISO shall consider a Market Participant's conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the Market Participant in the absence of market power. The categories of conduct that are inconsistent with competitive conduct include, but may not be limited to, the three categories of conduct specified in Section 2.4 below.

2.4 Categories of Conduct that May Warrant Mitigation

2.4.1 The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or generally the outcome of an ISO Real Time Market or Residual Unit Commitment process if exercised from a position of market power. Accordingly, the ISO shall monitor the ISO Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

(1) Physical withholding of an Electric Facility, in whole or in part, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving an ISO Market. Such withholding may include, but not be limited to: (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become totally or partially unavailable, (ii) refusing to offer bids or schedules for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, (iii) declining real-time bids called upon by the ISO (unless the ISO is informed in accordance with established procedures that the relevant resource for which the bid is submitted has undergone a forced outage or derate), or (iv) operating a Generating Unit in real-time to produce an output level that is less than the ISO's Dispatch Instruction.

(2) Economic withholding of an Electric Facility, that is, submitting bids for an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) so that: (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the bids will set a market clearing price.

(3) Uneconomic production from an Electric Facility, that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a network constraint.

3.1.1.1 Reference Levels

(a) For purposes of establishing reference levels, bid segments shall be defined as follows:

1. the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (Pmin) and maximum (Pmax) operating point.
2. for Energy bids submitted over the intertie Scheduling Points (import bids), 10 bid segments shall be established for each Scheduling Coordinator at each Scheduling Point based on historical volumes over the preceding 12 months.

A reference level for each bid segment shall be calculated for peak and off-peak periods on the basis of the following methods, listed in the following order of preference subject to the existence of sufficient data, where sufficient data means at least one data point per time period (peak or off-peak) for the bid segment. Peak periods shall be the periods Monday through Saturday from Hour Ending 0700 through Hour Ending 2200, excluding holidays. Off-Peak periods are all other hours.

1. The lower of the mean or the median of a resource's accepted bids in hours, where the Day-Ahead ISO Demand Forecast is less then or equal to 40,000 MW and the unit was Dispatched or Scheduled at least cost, over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices using the monthly proxy figure for natural gas prices posted on the ISO Home Page;
2. If the resource is a gas-fired unit that does not have significant energy limitations, the unit's default energy bid as set forth in Section 5.12 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh).

3. For non gas-fired units and gas-fired units that have significant energy limitations, a level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct

being examined by the ISO, and provided the Market Participant has provided sufficient data on a unit's energy limitations and operating costs (opportunity cost for energy limited resources) in accordance with specifications provided by the ISO.

4. The mean of the Economic Market Clearing Prices for the units' relevant location (zone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours, where the Day-Ahead ISO Demand Forecast is less then or equal to 40,000MW and the unit was Dispatched or Scheduled at least cost, over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices; or

5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the ISO shall determine a reference level on the basis of:

   i. the ISO's estimated costs of an Electric Facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or

   ii. an appropriate average of competitive bids of one or more similar Electric Facilities.

(b) The reference levels ($/MWh bid price) for the different bid segments of each resource (or import bid curve of a Scheduling Coordinator at a Scheduling Point) shall be made monotonically non-decreasing by the ISO by proceeding from the lowest MW bid segment moving through each higher MW bid segment. The reference level of each succeeding

(c) bid segment shall be the higher of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

3.2 Material Price Effects

3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Market, Mitigation Measures for economic withholding shall not be imposed unless conduct identified as specified above causes or contributes to a material change in one or more of the ISO market-clearing prices (MCPs). Initially, the thresholds to be used by the ISO to determine a material price effect shall be an increase of 100 percent or $50 per MWh, whichever is lower, in the MCP at any location (zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

3.2.2 Price Impact Analysis

The ISO shall determine the effect on prices of questioned conduct through automated computer modeling and analytical methods. An Automatic Mitigation Procedure (AMP) shall identify bids that have exceeded the conduct thresholds and shall compute the change in MCPs as a result of simultaneously setting all such bids to their Reference Levels. If a change in the MCP exceeds the Impact threshold stated in Section 3.2.1, those bids would be kept mitigated at their default bid levels as specified in Section 4.2.2 below.

3.2.3 Section 205 Filings

In addition, the ISO shall make a filing under Section 205 of the Federal Power Act with the Commission seeking authorization to apply an appropriate mitigation measure to conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in section 3.1.1 above, unless the ISO determines, from information provided by the Market Participant or Parties that would be subject to mitigation or other information available to the ISO that the conduct is attributable to legitimate competitive market forces or incentives. The following are examples of conduct that are deemed to depart significantly from the conduct that would be expected under competitive market conditions:

has responded to such condition by engaging in the economic withholding of an Electric Facility. In designing and implementing default bids, the ISO shall seek to avoid causing an Electric Facility to bid below its marginal cost.

4.2.2 Implementation

(a) If the criteria contained in Section 3 are met, the ISO may substitute a default bid for a bid submitted for an Electric Facility. The default bid shall establish a maximum value for one or more components of the submitted bid, equal to a reference level for that component determined as specified in Section 3.1.1.

(b) The Mitigation Measures will be applied to 1) the Residual Unit Commitment Processes based on the projected Real-time LMPs that are computed during these processes; 2) all bids submitted to the Real Time Imbalance Energy Market during the pre-dispatch process prior to the Real Time Imbalance Energy Market based on the projected Real-time LMPs that are computed during this process; and 3) to the ISO Day-Ahead and the Hour-Ahead Energy Markets.

(c) The bids that are mitigated in the Residual Unit Commitment Processes shall be reinstated to their original values and retested for both conduct and impact thresholds in the real-time pre-dispatch process. If the pre-dispatch market impact threshold is not violated, the bids shall be included in the real-time supply stack at their original (unmitigated) prices.

(d) An Electric Facility subject to a default bid shall be paid the LMP applicable to the output from the facility. Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the LMP applicable to that facility. With regard to imports into the ISO Control Area, importers subject to a default bid in the real-time market will be paid the higher of the simple average of the Dispatch Locational Marginal Prices for each hour or their default bid price. However, default bids by importers that are dispatched in the ISO Real-Time Market will not establish the Dispatch Interval Locational

Marginal Prices. Default bids by importer that are dispatched in the ISO Day-Ahead and Hour-Ahead Energy Market may establish LMPs in those markets.

(e) The ISO shall not use a default bid to determine revised LMPs for periods prior to the imposition of the default bid, except as may be specifically authorized by the Commission.

(f) The Mitigation Measures shall not be applied for the hours when the day-ahead system load forecast exceeds 40,000 MW. However, the bids used during the hours when the Day-Ahead system Demand exceeds 40,000 MW, even if at least cost, shall be excluded from the computation of the Reference Levels.

(g) The posting of the MCP may be delayed if necessary for the completion of automated mitigation procedures.

(h) Bids not mitigated under these Mitigation Measures shall remain subject to mitigation by other procedures specified in the ISO Tariff as may be appropriate.

4.3 Sanctions for Physical Withholding

The ISO may report a Market Participant the ISO believes to have engaged in physical withholding, including providing the ISO false information regarding the derating or outage of an Electric Facility, to the Federal Energy Regulatory Commission in accordance with Section 2.3.3.9.5 of the ISO Tariff. In addition, a Market Participant that fails to operate a Generating Unit in conformance with ISO Dispatch Instructions shall be subject to the penalties set forth in Section 11.2.4.1.2 of the ISO Tariff.

4.4 Duration of Mitigation Measures

Bids will be mitigated only in the specific hour that they violate the price and market impact thresholds.

5 FERC-ORDERED MEASURES

In addition to any mitigation measures specified above, the ISO shall administer, and apply when appropriate in accordance with their terms, such other mitigation measures as it may be directed to implement by order of the FERC.

6 DISPUTE RESOLUTION

If a Market Participant has reasonable grounds to believe that it has been adversely affected because a Mitigation Measure has been improperly applied or withheld, it may seek a determination in accordance with the dispute resolution provisions of the ISO Tariff. In no event, however, shall the ISO be

(a) the identification of the facility and location;

(b) the nature of the proposed Maintenance Outage;

(c) the preferred start and finish date for each Maintenance Outage; and

(d) where there is a possibility of flexibility, the earliest start date and the latest finish date, along with the actual duration of the Outage once it commences.

OCP 3.1.1.1 Additional Maintenance Outages

If conditions require, a Participating TO may, upon seventy-two (72) hours advance notice (or as specified in the Operating Procedures on the ISO Home Page), schedule with the ISO Outage Coordination Office a Maintenance Outage on its system. The Participating TO shall supply to the ISO the data set out in OCP 3.1.1.

OCP 3.1.2 Updates

Each Participating TO will provide the ISO with quarterly updates of the data provided under OCP 3.1.1 by close of business on the fifteenth (15th) day of each January, April, and July. These updates must identify known changes to any previously planned ISO Controlled Grid facility Maintenance Outages and any additional Outages anticipated over the next twelve months from the time of the report. As part of this update, each Participating TO must include all known planned Outages for the following twelve months. In addition, on the first day of every month the Participating TO shall provide an update of any known changes to any previously planned Maintenance Outages and additional Outages anticipated over the next two months (i.e. on January 1, the Participating TO would report updated information for February and March).

OCP 3.1.3 Changes to Planned Maintenance Outages

A Participating TO may submit changes to its planned Maintenance Outage information at any time, provided, however, that if the Participating TO 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. The ISO will, however, notify Market Participants and reflect the availability of transmission capacity in the Hour-Ahead Market as promptly as practicable.

OCP 3.1.4 Nature of Maintenance Outage Information

The information relating to each Maintenance Outage submitted by a Participating TO in accordance with OCP 3.1 constitutes a request for a long-range Maintenance Outage and is not considered an Approved Maintenance Outage until the ISO has notified the Participating TO of such approval pursuant to OCP 5.4.

SCHEDULES AND BIDS PROTOCOL (SBP)

SBP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SBP 1.1 Objectives

The objectives of this Protocol are:

(a) to require the provision of scheduling and bidding data to enable the ISO to undertake its scheduling process as described in the ISO Tariff and in the Scheduling Protocol (SP) taking into account the exercise of Firm Transmission Rights and rights under Existing Contracts for transmission service;

(b) to require the provision of Ancillary Services Schedules and bidding data required by the ISO to enable the ISO to conduct its Ancillary Services procurement as described in the ISO Tariff and in the SP; and

(c) to specify the contents of Schedules and to specify in detail the bidding data referred to in the ISO Tariff. The scheduling process and timing of the submission of data referred to are set forth in the SP.

SBP 1.2 Definitions

SBP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff unless otherwise specified. References to SBP are to this Protocol or to the stated paragraph of this Protocol.

SBP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meanings set opposite them:

"Bid" means an offer to sell Energy and/or Ancillary Services, or to purchase Energy, in ISO Markets.

"Existing Rights" as defined in Section 2.4.4.1.1 of the ISO Tariff, and

"Converted Rights" as defined in Section 2.4.4.2.1 of the ISO Tariff shall have the same meanings where used in this Protocol.

A Physical Scheduling Plant or System Unit shall be treated as a single Generating Unit for purposes of this Protocol, except as otherwise noted.

SBP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) References to time are references to the prevailing Pacific Time.

SBP 1.3 Scope

SBP 1.3.1 Scope of Application to Parties

The SBP applies to the following entities:

(a) Scheduling Coordinators (SCs);

(b) Participating Transmission Owners (PTOs); and

(c) the Independent System Operator (ISO).

SBP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

SBP 2 SCHEDULES AND NOTIFICATIONS

SBP 2.1 Contents of Schedules and Bid Data

SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Schedules and Bids. Except as noted, each of the following data sections can be submitted up to seven (7) days in advance.

SBP 2.1.1 Generation Section of Schedule and Bid Data

The Generation section of a Schedule or Bid will include the following information for each Generating Unit:

(a) SC's ID code;

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

(c) name of Generating Unit scheduled or bid;

(d) hourly scheduled Generating Unit output in MWh within the range of Energy Bid, including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule), for use in scheduling Existing Contracts or Firm Transmission Rights;

(e) Energy Bid, consisting of MW and $/MWh values for each Generating Unit for which a Bid is being submitted, stated as a staircase function composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of monotonically increasing quantity/price information;

(f) start-up cost in accordance with Section 31.2.3.2.3.3.1.1 of the ISO Tariff;

(g) Minimum Load Cost in accordance with Section 31.2.3.2.3.3.1.2 of the ISO Tariff; and

(h) flag indicating whether the ISO may use the bid in the Residual Unit Commitment Process (Y/N).

SBP 2.1.2 Demand Section of Schedule and Bid Data

The Demand section of a Schedule or Bid will include the following information for each Demand location:

(a) SC's ID code;

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

(c) Location Code – Demand location (which must be the name of a Load Zone, Customer Aggregation or bus);

(d) hourly scheduled MWh within the range of the Energy Bid, including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule);

(e) Energy Bid, consisting of MW and $/MWh values for each Load for which a Bid is being submitted as provided in Section 31.2.3.2.3.4.4.3 of the ISO Tariff, stated as a staircase function composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of monotonically decreasinq quantity/price information;

(f) minimum curtailment payment for a Particiating Load, as provided in Section 31.2.3.2.3.4.4.1 of the ISO Tariff;

(g) minimum hourly payment for a Participating Load, as provided in Section 31.2.3.2.3.4.4.2 of the ISO Tariff;

(h) time required for curtailment following notification to a Participating Load, in minutes;

(i) minimum off time stating the minimum number of hours a Participating Load is willing to be curtailed, in hours;

(j) maximum off time stating the maximum number of hours a Participating Load is willing to be curtailed, in hours;

(k) flag indicating the Participating Load bid is available for intra-hour redispatch. If this flag is set to "no" then the bid must be pre-dispatched and not re-dispatched during the real-time operating hour; and

(l) flag indicating whether the ISO may use the bid in the Residual Unit Commitment Process (Y/N).

SBP 2.1.3 External Import/Export Section of a Schedule and Bid Data

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

(a) SC's ID code;

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

(c) Scheduling Point (the name);

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

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

(f) external Control Area ID;

(g) contract type – transmission (TRNS), Energy (ENGY) or both (TR_EN);

(h) Schedule ID (NERC ID number);

(i) complete WSCC tag;

(j) hourly scheduled external imports/exports in MWh within the range of the Energy Bid, including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule) and with external imports into the ISO Controlled Grid reported as negative quantities and external exports from the ISO Controlled Grid reported as positive quantities;

(k) Energy Bid, consisting of MW and $/MWh values for each external import/export for which a Bid is being submitted , of a staircase function composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of monotonically increasing quantity/price information;

(l) ramp rate (MW/minute);

(m) minimum block of hours that bid must be dispatched; and

(n) flag indicating the bid is available for intra-hour redispatch. If this flag is set to "no" then the bid must be pre-dispatched and not re-dispatched during the real-time operating hour; and

(o) flag indicating whether the ISO may use the bid in the Residual Unit Commitment Process (Y/N).

SBP 2.1.4 Inter-Scheduling Coordinator Energy Section of a Schedule

In the event of an Inter-Scheduling Coordinator Energy Trade, the SCs who are parties to that trade must agree on a Location Code or Trading Hub at which the trade will be deemed to take place and notify the ISO accordingly. The Inter-Scheduling Coordinator Energy Trades section of a Schedule will include the following information for each Inter-Scheduling Coordinator Trade:

(a) SC's ID code;

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

(c) trading SC (buyer or seller);

(d) Trading Hub or Location Code;

(e) Schedule type – Energy (ENGY);

(f) hourly scheduled MWh, including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule), with Energy received by the SC reported as negative quantities and Energy sent from the SC reported as positive quantities; and

(g) the Generating Unit or Dispatchable Load that is the source or recipient of Energy traded if applicable.

SBP 2.1.5 Inter-Scheduling Coordinator Ancillary Service Trades Section of a Schedule

In the event of an Inter-Scheduling Coordinator Ancillary Service Trade, the SCs who are parties to that trade must agree on a Location Code at which the trade is deemed to take place and notify the ISO accordingly. The Ancillary Service obligations at the Location Code of each

Scheduling Coordinator will be adjusted to reflect the trade. The Inter-Scheduling Coordinator Ancillary Service Trades section of a Schedule will include the following information for each Inter-Scheduling Coordinator Ancillary Service Trade.

(a) SC's ID code;

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

(c) Trading SC (buyer or seller);

(d) Location Code;

(e) Schedule type-Regulation Up (ARGU), Regulation Down (ARGD), Spinning Reserve (ASPN), or Non-Spinning Reserve (ANSP); and

(f) Contracted MW amount of traded Ancillary Service obligation.

SBP 2.1.6 Contract Usage Template Associated with a Schedule that Includes the Use of Existing Contract Rights or Firm Transmission Rights

The contract usage template can be submitted the day prior to the Trading Day, as set forth in the timing requirements of the SP. The contract usage template can be submitted seven days in advance. However, the contract usage template will not be validated till the trade day. Each contract usage template must include the following information, in compliance with the ISO Data Templates and Validation Rules document which contains the format for submission of contract usage templates:

(a) SC's ID code:

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

(c) From Location (must be different than "to Location"), is the Location Code at which all sources specified in the contract usage template must be located;

(d) To Location (must be different than "from Location"), is the Location Code at which all sinks specified in the contract usage template must be located;

(e) Contract reference number for each Existing Contract or Firm Transmission Right for which transmission capacity has been reserved. Up to four contract reference numbers can be specified in this field, delimited by commas, for either Existing Contract usage or Firm Transmission Right usage, but not for both (i.e. Existing Contract rights and Firm Transmission Rights cannot be used together in linking sources and sinks on contract usage template).

(f) Usage ID (a unique identifier that allows a SC to submit multiple usages for a given contract right);

(g) Contract usage, in hourly scheduled MW, for the 24 hours of the Trading Day (for Generators, contract usage can be either positive or negative [i.e., for pumps]; for loads, contract usage must be positive; for external imports, contract usage must be negative; for external exports, contract usage must be positive). Each contract usage amount must be less than or equal to the amount of Existing Contract rights specified by the relevant Participating Transmission Owner(s) of Firm Transmission Rights, whichever the case may be. Additionally, any Energy Bids that may also be submitted for any particular resource (Source or Sink) that is also identified on a contract usage template must not overlap the contract usages specified for a particular resource in a contract usage template;

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

(i) Sources and Sinks, of hourly scheduled MWH (in the case of Energy usages) or MW (in the case of Ancillary Services usages), specified on the contract usage template must be balanced (except for Ancillary Services which need not be specified with Sinks). Sources and Sinks must match the points of receipt and points of delivery associated with the Existing Contract or the Firm Transmission Right. Each Energy schedule or Ancillary Service bid or self-provided schedule associated with a particular source or sink must have an hourly usage schedule that is greater than or equal to the amounts specified on contract usage templates. The source/sink section of a contract usage template will include the following information (up to five combinations of sources and sinks can be specified on a single contract usage template if an SC is submitting the templates in accordance with SBP 7.2(a), or up to 20 combinations of sources and sinks if an SC is submitting the templates in accordance with SBP 7.2(b) or SBP 7.2(c));

(1) Type of resource – generation (GEN), load (LOAD), or interchange (INTRCHNGE);

(2) Resource_ID – generator_ID, load_ID, or tie_point;

(3) Resource_ID2 (required only for individual interchange schedules);

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

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

SBP 2.2 Validation of Schedules and Bids

Each SC will be assigned a workspace within the ISO's scheduling system. Each workspace will have a work area for Day-Ahead and Hour-Ahead Schedules and Bids. The SC shall only be allowed to access and manipulate its Schedule and Bid data within this workspace. Each area is organized into segments. A segment is used to hold the SC's Schedules relating to the same Trading Day. The Schedule validation process is divided into two stages. The ISO shall carry out the first stage validation immediately after it has received a Schedule. The ISO shall carry out the second stage validation ten (10) minutes before (pre-validation) and immediately after each deadline (as specified in the SP) for submission of Schedules. However, a SC can also initiate the stage two validation at any time prior to that deadline, as described in more detail in the SP. If the SC adds a new Schedule or modifies an existing Schedule, that Schedule must be re-validated. SCs must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Schedules and Bids.

SBP 2.2.1 Stage One Validation

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

SBP 2.2.2 Stage Two Validation

During stage two validation, Schedules will be checked to determine whether Inter-Scheduling Coordinator Trades (whether purchases or sales) equals the amount and location stated in the counterparty's trade. The SC will be notified if the counterparty's trade to any Inter-Scheduling Coordinator Trade has not been submitted, or is infeasible (e.g. if both SCs are selling or both are buying). This validation is performed in accordance with the timing requirement described in the SP. An SC can also check whether its Schedules will pass the ISO's stage two validation by manually initiating, as described in the SP, at any time prior to the deadline for submission of Schedules. It is the SC's responsibility to perform such checks, if desired. The SC will be notified immediately through WEnet of any validation errors. For each error detected, an error message will be generated by the ISO in the SC's notification screen which will specify the nature of the error. If the ISO detects a mismatch in Inter-Scheduling Coordinator Trades, the ISO will notify both SCs of the mismatch in Energy quantity and/or location. The SC can then look at thenotification messages to review the detailed list of errors, make changes, and resubmit the Schedule if it is still within the timing requirements of the SP. The SC is also notified of successful validation via WEnet.

SBP 2.3 Schedule Feasibility

The Generation section of a Schedule or Bid must accurately reflect the physical capability of each Generating Unit identified in the Schedule (including each Generating Unit's ability to ramp from one hour to the next). For example, a 500 MW Generating Unit specified with a ramp rate of 2 MW/min and an operating point of 100 MWh for the current operating hour is not physically capable of generating 300 MWh in the next operating hour.

SBP 2.4 Default Data Requirements

Scheduling Coordinators for all Generating Units shall submit the following operating constraint information to the ISO in the format specified by the ISO and posted on the ISO Home Page:

(a) maximum operating limit, defined as the maximum power output limit of a unit while it is on-line;

(b) minimum dispatchable load level, defined as the minimum power output limit of a unit while it is on-line and able to respond to Dispatch instructions, also referred to as the minimum load;

(c) minimum operating limit, defined as the minimum power output limit of a unit while it is on-line regardless of whether the unit is available for dispatch, which may include operating states such as "flash tank";

(d) regulating limits, defined as the minimum and maximum power output limits of a unit while it is providing Regulation;

(e) reactive power limits, defined as the minimum and maximum limits of reactive power produced by a unit while it is on-line;

(f) ramp rates associated with varying levels of production, defined as the rate at which a unit increases or decreases its power output to perform schedule changes across time periods, in MW per minute;

(g) minimum up time, defined as the minimum time that a unit must stay on-line between start-up and shutdown, due to physical operating constraints, in minutes;

(h) start-up time, defined as the time required for a unit to start up, from the time of receipt of an ISO notification to start, until the time the generating unit is synchronized to the grid and producing Energy, in minutes;

(i) shutdown time, defined as the time required for a unit to shut down, in minutes;

(j) minimum down time, defined as the minimum time that a unit must stay off-line after the start of a shutdown, including the start-up and shutdown time, in minutes;

(k) time to remain at minimum operating limit, defined as the amount of time that a unit must be run at or near its minimum operating limit before it can be restored to its minimum dispatchable load level (equal to zero if the minimum dispatchable load level and the minimum operating limit are the same);

(l) time to reach minimum dispatchable load level, defined as the amount of time required for a unit to move from its minimum operating limit to its minimum dispatchable load level (equal to zero if these levels are the same);

(m) maximum number of daily start-ups, defined as the maximum number of times that a unit is allowed to shutdown and start-up within a day, in events per day;

(n) start-up auxiliary power data, defined as the electrical power used by a unit during start-up;

(o) emissions rates and costs, measured as the pounds of emissions per MWh for each type of emissions at the same resource loading points that are used to provide heat input data or production cost data (discussed below) and the cost of emissions in $ per pound for each type of emissions;

(p) start-up emissions data and costs, measured as the pounds of emissions produced during start-up of a unit for each type of emissions and the cost of emissions in $ per pound for each type of emissions;

(q) Energy limitations, which are limits on the amount of power that can be produced by a unit over the Day-Ahead time horizon.

Scheduling Coordinators for Gas-Fired Generating Units shall submit the following additional operating data in the format specified by the ISO and posted on the ISO Home Page:

(a) heat input data, stating the average heat rate (BTU/kWh) at up to 11 levels of production, representing a range of resource loading points that must include data at or near the minimum production level (minimum load) and maximum output; and

(b) start-up fuel data, stating the fuel use, in BTU per start, expected for the start-up of a generator that has been off-line for representative periods of time. Start-up fuel use may be provided for up to ten representative amounts of time that a generator has been off-line (including shutdown and start-up time), such as hot starts, cold starts, and other conditions.

Scheduling Coordinators for Generating Units that are not gas-fired shall submit the following additional operating data in the format specified by the ISO and posted on the ISO Home Page:

(a) production cost data, stating the average operating cost ($/MWh) at up to 11 levels of production representing a range of resource loading points that must include data at or near the minimum production level (minimum load) and maximum output;

(b) start-up cost data, stating the cost in dollars per start expected for the start-up of a generator that has been off-line for representative periods of time, which may be provided for up to ten representative amounts of time that a generator has been off-line (including shutdown and start-up time), such as hot starts, cold starts, and other conditions;

(c) fuel type; and

(d) applicable fuel index, available from public data sources or standard trade publications, for the ISO to use in updating the provided production cost data and start-up cost data.

Scheduling Coordinators must file periodic updates of this information at the direction of FERC or the ISO, or when the Scheduling Coordinator is aware that significant changes in the data have occurred. In the event that Scheduling Coordinators do not supply the required data, the ISO may use data available from other sources, including a current or previous Reliability Must-Run Contract with the Generator, a Participating Generator Agreement listing that Generating Unit, or data for similar technologies.

SBP 3 EXISTING CONTRACTS FOR TRANSMISSION SERVICE

SBP 3.1 Application of SBP 3 to Rights under Existing Contracts

SBP 3.1.1 Existing Rights

The provisions of Sections 2.4.3 and 2.4.4 of the ISO Tariff shall, with respect to the exercise of Existing Rights following the ISO Operations instruction and that references a single Existing Contract or a set of interdependent Existing Contracts; the provisions of SBP 3.4 will apply to the validation of scheduled uses of Existing Contract transmission rights);

(b) whether the instruction can be exercised independent of the ISO's day-to-day involvement (Yes/No);

(c) name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Responsible PTO;

(d) name(s) and number(s) of Existing Contract(s);

(e) path name(s) and location(s) (described in terms of the Location Codes for the point(s) of receipt and point(s) of delivery);

(f) names of the party(ies) to the Existing Contract(s);

(g) SC ID code: the ID number of the SC who will submit Schedules which make use of the Existing Contract(s) for the party(ies) indicated in (f);

(h) type(s) of rights, by rights holder, by Existing Rights;

(i) type(s) of service, by rights holder, by Existing Contract (firm, conditional firm, or non-firm), with priorities for firm and conditional firm transmission services as described in the SP;

(j) amount of transmission service, by rights holder, by Existing Contract expressed in MW;

(k) for Day-Ahead scheduling purposes, the time of the day preceding the Trading Day at which the SC submits Schedules to the ISO referencing the Existing Contract(s) identified in the instructions;

(l) for Hour-Ahead or real time scheduling purposes, the number of minutes prior to the start of the Settlement Period of delivery at which the SC may submit Schedule adjustments to the ISO regarding the Existing Rights under the Existing Contract(s) identified in the instructions;

(m) whether or not real time modifications to Schedules associated with Existing Rights are allowed at any time during the Settlement Period;

(n) Service period(s) of the Existing Contract(s);

(o) any special procedures which would require curtailments to be implemented by the ISO in any manner different than that specified in SBP 3.3.2. Any such instructions submitted to the ISO must be clear, unambiguous, and not require the ISO to make any judgments or interpretations as to the meaning,

SBP 3.3.5 Timing of Submission of Instructions to ISO

SBP 3.3.5.1 Initial Submittal of Instructions

The Responsible PTOs shall submit instructions to the ISO associated with Existing Contracts or sets of interdependent Existing Contracts thirty (30) days prior to either (a) the ISO Operations Date or (b) the date on which the scheduling or curtailment of the use of the Existing Rights is to commence pursuant to Sections 2.4.3 or 2.4.4 of the ISO Tariff.

SBP 3.3.5.2 Changes to Instructions

Updates or changes to the instructions must be submitted to the ISO by the Responsible PTO, on an as needed or as required basis determined by the parties to the Existing Contracts. The ISO will implement the updated or changed instructions as soon as practicable but not later than seven (7) days after receiving clear and unambiguous details of the updated or changed instructions. If the ISO finds the instructions to be inconsistent with respect to the ISO Protocols or the ISO Tariff, the ISO will notify the Responsible PTO within forty-eight (48) hours after receipt of the updated or changed instructions indicating the nature of the problem and allowing the Responsible PTO to resubmit the instructions as if they were new, updated or changed instructions to which the provisions of this SBP 3.3 will apply. If the ISO finds the updated or changed instructions to be acceptable, the ISO will time-stamp the updated instructions as received, confirm such receipt to the Responsible PTO, and indicate the time at which the updated instructions take effect if prior to the seven (7) day deadline referred to above.

SBP 3.4 Validation of Existing Contract Schedules

Each Schedule submitted to the ISO by a SC representing a rights holder to an Existing Contract must include a valid contract reference number in accordance with SBP 3.3. If a match of the Schedule's contract reference number is found in the ISO's database and the Schedule is consistent with the instructions submitted previously by the Responsible PTO, the Schedule will be implemented in accordance with the instructions. If a match of the Schedule's contract reference number cannot be found in the ISO's database, the ISO will issue an error message to the SC via the WEnet (as described in SBP 2.2.1) and indicate the nature of the problem. The ISO will assist the SC, within reason, in resolving the problem so that the SC is able to submit the Schedule successfully as soon as possible within the timing requirements of the SP. If the SC uses a contract reference number for which the responsible PTO has not reserved transmission capacity on a particular path (*i.e.,* the contract reference Number(s) included on a contract usage template cannot be found in the ISO's scheduling applications table of contract reference numbers), the scheduled use will be invalidated and the SC notified by the ISO's issuance of an invalidated usage information template.

SBP 4 [Not Used]

SBP 4.1 [Not Used]

SBP 4.2 [Not Used]

SBP 4.3 [Not Used]

SBP 4.4 [Not Used]

SBP 4.5 [Not Used]

SBP 4.5.1 [Not Used]

SBP 4.5.2 [Not Used]

SBP 4.6 [NOT USED]

SBP 5 ANCILLARY SERVICES

SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Ancillary Services schedules and bids. Additionally, SCs should refer to the Ancillary Services bid evaluation and scheduling principles contained in the SP. As also described in the SP, the resources constituting a System Unit which submitted Ancillary Services bids or schedules and which, as a result, has been accepted by the ISO to supply Ancillary Services in a Settlement Period must be disclosed to the ISO one (1) hour prior to the start of the Settlement Period.

SBP 5.1 Content of Ancillary Services Schedules and Bids

Ancillary Services in the Day-Ahead Market and the Hour-Ahead Market are comprised of the following: Regulation, Spinning Reserve, and Non-Spinning Reserve. Each Generating Unit (including Physical Scheduling Plants), System Unit, Dispatchable Load or System Resource for which a SC wishes to submit Ancillary Services Schedules and Bids must meet the requirements set forth in the Ancillary Services Requirements Protocol (ASRP). For each Ancillary Service offered to the ISO Market or self-provided, SCs must also provide an Energy Bid in the form described in SBP 2. The same resource capacity may be included in more than one ISO Ancillary Service Bid at the same time (the evaluation of such multiple offers between Ancillary Services markets to eliminate double counting of capacity is described in the SP). Each of the following data sections can be submitted up to seven (7) days in advance. There is no provision for external exports with regard to Ancillary Services bids. The functionality necessary to accept such bids does not exist in the ISO scheduling software.

SBP 5.1.1 Regulation

SBP 5.1.1.1 Regulation: Generating Units or System Units

Each SC desiring to self-provide Regulation or to bid Regulation capacity will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Regulation Ancillary Service (ANC_SRVC);

(b) SC's ID code;

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

(d) Generating Unit or System Unit ID code;

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

(f) upward and downward range of Generating Unit or System Unit capacity over which the Generating Unit or System Unit is offering to provide Regulation; abd

(g) bid price for Regulation capacity ($/MW), stated separately for Regulation Up and Regulation Down.

SBP 5.1.1.2 Regulation: External Imports

Each SC desiring to self-provide Regulation or to bid Regulation capacity will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: (Regulation Ancillary Service);

(b) SC's ID code;

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

(d) Scheduling Point (the name)

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

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WSCC tag;

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

(j) in the case of Existing contracts, the applicable contract reference number;

(k) upward and downward range of System Resource capacity over which the System Resource is offering to provide Regulation;

(l) System Resource operating limits (high and low MW);

(m) ramp rate (MW/minute); and

(n) bid price for Regulation capacity ($/MW) stated separately for Regulation Up and Regulation Down.

SBP 5.1.2 Spinning Reserve

SBP 5.1.2.1 Spinning Reserve: Generating Units or System Units

Each SC desiring to self-provide Spinning Reserve or to bid Spinning Reserve capacity will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC);

(b) SC's ID code;

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

(d) Generating Unit or System Unit ID code;

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

(f) Spinning Reserve capacity (MW) synchronized to the system, immediately responsive to system frequency, and available within ten (10) minutes;

(g) bid price for Spinning Reserve capacity ($/MW); and

(h) an indication as to whether the capacity reserved was available to provide Imbalance Energy only during an unplanned Outage, a Contingency, or an imminent or actual System Emergency.

SBP 5.1.2.2 Spinning Reserve: External Imports/Exports

Each SC desiring to bid or self-provide Spinning Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC);

(b) SC's ID code;

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

(d) Scheduling Point (the name);

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

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WSCC tag;

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

(j) export flag, a "YES" indicates an external export and a "NO" indicates an external import;

(k) In the case of Existing Contracts, the applicable contract reference number;

(l) Spinning Reserve capacity (MW) synchronized to the system, immediately responsive to system frequency, and available at the point of Interchange with the ISO Control Area within ten (10) minutes of the ISO calling for the import;

(m) ramp rate (MW/minute); and

(n) an indication as to whether the capacity reserved was available to provide Imbalance Energy only during an unplanned Outage, a Contingency, or an imminent or actual System Emergency.

SBP 5.1.3 Non-Spinning Reserve

SBP 5.1.3.1 Non-Spinning Reserve: Generating Units or System Units

Each SC desiring to self-provide Non-Spinning Reserve or bid Non-Spinning Reserve capacity will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC);

(b) SC's ID code;

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

(d) Generating Unit or System Unit ID code;

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

(f) time to synchronize following notification (less than ten (10) minutes mandatory);

(g) Non-Spinning Reserve capacity available within ten (10) minutes following notification (MW);

(h) bid price for Non-Spinning Reserve capacity ($/MW); and

(i) an indication as to whether the capacity reserved was available to provide Imbalance Energy only during an unplanned Outage, a Contingency, or an imminent or actual System Emergency.

SBP 5.1.3.2 Non-Spinning Reserve: Dispatchable Load

Each SC desiring to self-provide Non-Spinning Reserve or to bid Non-Spinning Reserve capacity will submit the following information for each relevant Dispatchable Load for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead and Hour-Ahead) and Trading Day;

(d) available Dispatchable Load;

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

(f) time to interrupt (must be less than ten minutes);

(g) amount of Dispatchable Load that can be interrupted within ten (10) minutes following notification (MW); and

(h) bid price for Non-Spinning Reserve capacity ($/MW), and

(i) an indication as to whether the capacity reserved was available to provide Imbalance Energy only during an unplanned Outage, a Contingency, or an imminent or actual System Emergency.

SBP 5.1.3.3 Non-Spinning Reserve: External Imports/Exports

Each SC desiring to bid or self-provide Non-Spinning Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC);

(b) SC's ID code;

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

(d) Scheduling Point (the name);

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

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WSCC tag;

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

(j) export flag, a "YES" indicates an external export and a "NO" indicates an external import;

(k) In the case of Existing Contracts, the applicable contract reference number;

(l) time to synchronize following notification (less than ten (10) minutes mandatory);

(m) Non-Spinning Reserve capacity (MW available at the point of Interchange with the ISO within ten (10) minutes of the ISO calling for the import;

(n) ramp rate (MW/minute);

(o) Bid price for Non-Spinning Reserve capacity ($/MW); and

(p) an indication as to whether the capacity reserved was available to provide Imbalance Energy only during an unplanned Outage, a Contingency, or an imminent or actual System Emergency.

SBP 5.1.4 [Not Used]

SBP 5.1.4.1 [Not Used]

SBP 5.1.4.2 [Not Used]

SBP 5.1.4.3 [Not Used]

SBP 5.2 Validation of Ancillary Services Bids

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

SBP 5.2.1 Stage One Validation

During stage one validation, each incoming Ancillary Services schedule or bid will be validated to verify proper content, format and syntax. A technical validation will be performed to verify that a schedule or bid quantity of Regulation, Spinning Reserve, or Non-Spinning Reserve does not exceed the available capacity for Regulation and Operating Reserves on the Generating Units, System Units, Dispatchable Load and external imports/exports scheduled or bid. The SC will be notified immediately through WEnet of any validation errors. For each error detected, an error message will be generated by the ISO in the SC's notification screen which will specify the nature of the error. The SC can then look at the notification messages to review the detailed list of errors, make changes, and resubmit if it is still within the timing requirements of the SP. The SC is also notified of successful validation via WEnet.

SBP 5.2.2 Stage Two Validation

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

SBP 5.2.3 Validation Checks

The ISO's stage one validation checks are performed automatically whenever Ancillary Services Schedules and bids are submitted, as described in the SP. The ISO's stage two validation is performed automatically in accordance with the timing requirements described in the SP. A SC can also check whether its Ancillary Services Schedules and bids will pass the ISO's stage two validation by manually initiating validation of its Ancillary Services Schedules and bids, as described in the SP, at any time prior to the deadline for submission of Ancillary Services Schedules and bids. It is a SC's responsibility to perform such checks.

SBP 5.3 [Not Used]

SBP 6 [Not Used]

SBP 6.1 [Not Used]

SBP 6.1.1 [Not Used]

[Page Not Used]

SBP 6.1.2 [Not Used]

SBP 6.1.3 [Not Used]

SBP 6.2 [Not Used]

[Page Not Used]

SBP 6.3 [Not Used]

SBP 6.4 [Not Used]

SBP 7 INTERFACE REQUIREMENTS

SBP 7.1 WEnet

WEnet provides the backbone on which any of three communications mechanisms will be utilized. These are:

(a) use of a web browser such as Netscape;

(b) use of File Transfer Protocol (FTP); or

(c) use of an Application Programming Interface (API).

Details of the technical aspects of each of these mechanisms, including information on how to change mechanisms and back-up procedures for individual SC failures, will be made available by the ISO to SCs on request. It is assumed that each SC has made application for and signed a Scheduling Coordinator Agreement. As such, each SC will already be familiar with and have arranged the mechanism, including security arrangements, by which it will initially communicate with the ISO.

SBP 7.2 Templates

The ISO Data Templates and Validation Rules document provides a description of the templates which will be utilized to enter data into the ISO's systems. For each of the three communications mechanisms, data entry is as follows:

(a) direct entry of data into the template screens through the use of a browser;

(b) upload of ASCII delimited text through use of an upload button on the template screens which activates the FTP mechanism; or

Transmission Rights/Curtailment Instructions Template

(a) Contract Ref #	(b) Ind Imp	(c) Contact Person
[a single number]	[yes/no]	[phone number] [name(s)]

Submitted By PTO: ____________________

Date Received By ISO: ________________

Date Accepted By ISO: ________________

	(e) Path Name(s) and Location(s)						(i)(j) Types and Amounts of Transmission Service			(k) DA	(l) HA	(m) RT	(n) Service Period	
(d) Contract Name(s)/Number(s)	Path Name(s)	POR Zone	POD Zone	(f) Party	(g) SC ID	(h) ER/NCR	Firm /1/	CF /1/	N-F	(hour-ending)	(minutes)	(yes/no)	Beginning	Ending
[name/number 1]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1400]	[30]	[yes]	[hh/dd/mm/yy]	[hh/dd/mm/yy]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]
[name/number 2]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1400]	[20]	[yes]	["]	["]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]
[name/number n]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1500]	[20]	[yes]	["]	["]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]

(o) Non-Emergency Curtailments

[If other than pro rata, attach spreadsheet for ISO to use in allocating curtailments to rights holders between the indicated zones. Otherwise, indicate "pro rata" here.]

(p) Emergency Curtailments

[Describe special procedures/requirements here. Indicate "N/A" if none.]

/1/ Priorities for firm and conditional firm transmission service are indicated as described in the SP.

SCHEDULING PROTOCOL (SP)

SP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SP 1.1 Objectives

The objectives of this Protocol are:

(a) to process the scheduling input data (submitted to the ISO under the Ancillary Service Requirements Protocol (ASRP), the Demand Forecasting Protocol (DFP), and the Schedules and Bids Protocol (SBP)) in order to develop Final Schedules for the Day-Ahead and Hour-Ahead Markets (real time management of the ISO Controlled Grid is addressed in the Dispatch Protocol (DP));

(b) to provide for the scheduling of the use of Firm Transmission Rights and use of transmission service rights under Existing Contracts;

(c) to assist the ISO in purchasing Ancillary Services; and

(d) to manage Congestion.

(e) to clear the Energy markets; and

(f) to commit resources

SP 1.2 Definitions

SP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff. References to SP are to this Protocol or to the stated paragraph of this Protocol.

SP 1.2.2 [Not Used]

SP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol to a given agreement, ISO Protocol or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made.

(c) The captions and headings in this Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) References to time are references to the prevailing Pacific time.

SP 1.3 Scope

SP 1.3.1 Scope of Application to Parties

The SP applies to the following entities:

(a) Scheduling Coordinators (SCs);

(b) Utility Distribution Companies (UDCs);

(c) Participating Transmission Owners (PTOs);

(c) interfacing Control Area operators in accordance with Inter-Control Area agreements entered into with the ISO, to the extent the agreement between the Connected Entity and the ISO so provides; and

(d) the Independent System Operator (ISO).

SP 1.3.2 Liability of ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

SP 2 INTERFACE REQUIREMENTS

The WEnet interface requirements and associated information requirements are described in the SBP.

SP 3 Time Lines

(a) Consistent with Sections 2.2.12.1 and 2.5.2.2 of the ISO Tariff, the ISO may implement any temporary variation or waiver of timing requirements contained in this SP (including the omission of any step) if any of the following criteria are met:

(i) the ISO receives Schedules that require delay in performing Day-Ahead Market or Hour-Ahead Market evaluations;

(ii) the ISO requires additional time to fulfill its responsibilities pursuant to Section 2.2.2 of the ISO Tariff;

(iii) problems with data or the processing of data cause a delay in receiving or issuing Schedules or publishing information on the WEnet;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Schedules or publishing information on the WEnet; or

(v) such waiver or variation of timing requirements is reasonably necessary to preserve System Reliability, prevent an imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency.

(b) If the ISO temporarily implements a waiver or variation of such timing requirements (including the omission of any step) consistent with Section 2.2.12.1 of the ISO Tariff and SP 3(a), the ISO will publish the following information on WEnet as soon as practicable:

(i) the exact timing requirements affected;

(ii) details of any substituted timing requirements;

(iii) an estimate of the period for which this waiver or variation will apply; and

(iv) reasons for the temporary waiver or variation.

(c) If, despite the variation of any time requirement or the omission of any step, the ISO fails to receive sufficient Schedules to operate the Day-Ahead Market, the ISO may abort the Day-Ahead Market and require all Schedules to be submitted, and Congestion Management to be performed, in the Hour-Ahead Market.

(d) If, despite the variation of any time requirement or omission of any step, the ISO fails to receive sufficient Schedules to operate the Hour-Ahead Market, the ISO may abort the Hour-Ahead Market and function in real time.

(e) The incorporation of the scheduling of the use of rights under Existing Contracts into the ISO's Day-Ahead, Hour-Ahead and real time processes is additionally described in SP 7 and in the SBP.

SP 3.1 Schedules

SP 3.1.1 Balanced Schedules

A Scheduling Coordinator's portfolio is not required to be balanced relative to scheduled Generator, Load and System Resources. A Scheduling Coordinator may voluntarily submit a Balanced Schedule.

(a) A Scheduling Coordinator that chooses to make use of an Existing Contract must submit a Balanced Schedule that identifies the Source and Sink. The Source shall be at the originating point of the Existing Contract right and the Sink shall be at the destination point of the Existing Contract right.

(b) A Scheduling Coordinator that chooses to make use of a Point-to-Point Firm Transmission Right priority must identify a Balanced Schedule in which the Source shall be at the originating point of the FTR and the Sink shall be at the destination point of the FTR.

(c) A bi-lateral or self-committed schedule may be expressed as a Balanced Schedule

SP 3.1.2 Preferred Schedules

The Preferred Schedule is the initial Schedule submitted by a SC in the Day-Ahead Market or Hour-Ahead Market.

SP 3.1.3 Seven-Day Advance Schedules

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

SP 3.1.4 [Not Used]

SP 3.1.5 **[Not Used]**

SP 3.1.6 Final Schedules

Following the Day-Ahead and Hour-Ahead Markets, the ISO shall issue Final Schedules that reflect the outcome of those markets. A modification flag, set by the ISO, will indicate whether the ISO has modified the Preferred Schedule as a result of conducting the Day-Ahead or Hour-Ahead Market.

SP 3.2 Day-Ahead Market

The Day-Ahead Market is an integrated forward market for Energy, Congestion Management, Unit Commitment Ancillary Services. The Day-Ahead Market produces Final Schedules for each Settlement Period of the Trading Day. The Day-Ahead Market starts at 6:00 pm two days ahead of the Trading Day and ends at 1:00 pm on the day ahead of the Trading Day, at which time the ISO issues the Final Day-Ahead Schedules.

SP 3.2.1 By 6:00 pm, Two Days Ahead

By 6:00 pm two days ahead of the Trading Day (for example, by 6:00 pm on Monday for the Wednesday Trading Day), the ISO will publish, via OASIS, the following information for each Settlement Period of the Trading Day:

(a) a forecast of conditions on the ISO Controlled Grid, including known transmission line and other transmission facility Outages for up to the next 45 days;

(b) **[Not Used]**

(c) advisory Demand Forecasts for the system and for each UDC and Load Zone;

(d) expected Ancillary Services requirements for the ISO Control Area for each Ancillary Service by Ancillary Service Region (see the ASRP for the details on these requirements);

(e) a forecast of Loop Flows over interfaces with other Control Areas;

(f) a forecast of the potential for Congestion conditions;

(g) a forecast of total and Available Transmission Capacity over certain transmission paths;

(h) a description of any temporary adjustments to Ancillary Service standards that the ISO has determined by that time to make, in accordance with Section 2.5.2.2.

SP 3.2.1.1 By Two Hours Before the Deadline for Submitting Initial Preferred Schedules for the Day-Ahead Market, One Day Ahead

By two hours before the deadline for submitting Initial Preferred Schedules for the Day-Ahead Market on the day ahead of the Trading Day, the ISO will notify SCs of the Energy Requirements from any Reliability Must-Run Units which the ISO requires to run in the Trading Day, except in those instances where a Reliability Must-Run Unit requires more than one day's notice, in which case the ISO may notify the applicable SC more than one day in advance of the Trading Day in accordance with Section 31.2.2 of this Tariff;

SP 3.2.1.2 By One Hour After Receipt of the RMR Dispatch Notice, One Day Ahead

By one hour after receipt of the RMR Dispatch Notice on the day prior to the Trading Day, SCs that have been notified that a Reliability Must-Run Unit is required to run in the Trading Day will inform the ISO, with regard to each hour for which the ISO has provided such notice, whether the RMR Owner will take payment from the market or under the RMR Contract in accordance with 31.2.2 of this Tariff.

SP 3.2.2 By 6:00 am, One Day Ahead

By 6:00 am on the day ahead of the Trading Day (for example, by 6:00 am on Tuesday for the Wednesday Trading Day), the following information flows for each Settlement Period of the Trading Day will be required to take place:

(a) **[Not Used];**

(b) the ISO will publish, via OASIS, an updated Demand Forecasts for the system and for each UDC and Load Zones and of the Ancillary Services requirements for the ISO Control Area for each Ancillary Service and by Ancillary Service Region;

(c) the ISO will validate (in accordance with the SBP) the information submitted above by SCs and UDCs;

(d) Forecasted total and Available Transmission Capacity for commercially significant WECC rated transmission paths internal to the ISO Control Area and External Control Areas.

(e) Load Distribution Factors (LDFs) for trading hubs and Load Aggregation Points.

(f) Power Transfer Distribution Factors (PTDFs) for the state of the network as forecasted for the Trading Day.

(g) A description of any temporary adjustments to Ancillary Service standards that the ISO has determined by that time to make, in accordance with Section 2.5.2.2

SP 3.2.3 [Not Used]

SP 3.2.4 By 8:00 am, One Day Ahead

By 8:00 am on the day ahead of the Trading Day (for example, by 8:00 am on Tuesday for the Wednesday Trading Day), and for each Settlement Period of that Trading Day, Firm Transmission Rights owners will notify the ISO, via the Secondary Registration System or other means established by the ISO, of any transaction of Firm Transmission Rights and of any changes in SCs' rights to schedule the use of Firm Transmission Rights.

SP 3.2.5 By 8:30 am, One Day Ahead

By 8:30 am on the day ahead of the Trading Day (for example, by 8:30 am on Tuesday for the Wednesday Trading Day), and for each Settlement Period of that Trading Day, Participating Transmission Owners will notify the ISO, via e-mail of an electronic spreadsheet or other means established by the ISO, of the amounts of transmission capacity to reserve for its transmission service customers under Existing Contracts. Upon receiving this information, the ISO will determine if the Existing Contracts capacity reservations are simultaneously feasible. By 9:00 a.m., the ISO shall calculate and publish the simultaneously-feasible Existing Contracts capacity reservations. After publishing the adjusted scheduling rights for Existing Contract rights and Firm Transmission Rights, SCs may submit contract usage templates (in accordance with the SBP) for validation by the ISO prior to the ISO's deadline for receiving Preferred Day-Ahead Schedules.

SP 3.2.6 By 10:00 am, One Day Ahead

SP 3.2.6.1 Actions by SCs and the ISO

By 10:00 am on the day ahead of the Trading Day (for example, by 10:00 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day (see SP 3.2.6.2 for information on the pre-validation performed at ten (10) minutes prior to the 10:00 am deadline):

(a) SCs will submit their Preferred Day-Ahead Schedules to the ISO in accordance with the SBP;

(b) SCs will submit their Energy Bids and Start-up and Minimum Load costs, if any, to the ISO in accordance with the SBP;

(c) SCs will submit their Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;

(d) SCs will submit their schedules for self-provided Ancillary Services, if any, to the ISO in accordance with the SBP and SP 9;

(e) the ISO will validate (in accordance with the SBP) all SC submitted Preferred Day-Ahead Schedules and Energy bids;

(f) the ISO will validate (in accordance with the SBP) all SC submitted schedules for self-provided Ancillary Services, Inter-

Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which were part of their Preferred Day-Ahead Schedules;

(g) the ISO will validate (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights; and

(h) the ISO will validate that all SC submitted Preferred Day Ahead Schedules are compatible with the RMR requirements of which SCs were notified for that Trading Day and with the SCs' elected options for delivering the required Energy;

SP 3.2.6.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Preferred Day-Ahead Schedules, Energy Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in the SBP. The purpose of this is to allow the SCs, particularly those involved in the Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of each SC's pre-validation to that SC, via WEnet.

SP 3.2.6.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for all Settlement Periods of the relevant Trading Day. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as New Firm Uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist SCs to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades contained in their Preferred Schedules in accordance with SP 3.2.6.4. Except with respect to contract usage templates (for which SCs can check whether or not their submittal will pass the ISO's validation checks between 9:00 am and 10:00 am), SCs may check at any time prior to 10:00 am whether or not their submittal will pass the ISO's validation checks at 10:00 am. It is the responsibility of the SCs to perform such checks since Preferred

Day-Ahead Schedules, Energy Bids, Schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 10:00 am. The ISO will immediately communicate the results of each SC's 10:00 am validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing Transmission Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the ETC rights will be considered a New Firm Use (NFU) and will be exposed to Congestion and Energy charges.

SP 3.2.6.4 Inter-Scheduling Coordinator Energy Trades - Mismatches

During the initial period of ISO operations, if the ISO detects a mismatch in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades, the ISO will promptly notify both the receiving and sending SCs that a mismatch exists. If the SCs are unable to resolve the mismatch and provided there is no dispute as to whether the trade occurred or over its location, then the ISO may reconcile mismatches after the close of the market but prior to Settlement:

(a) If there is a dispute between the SCs as to whether the trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears.

(b) **[Not Used].**

(c) The adjustments to each SC's portfolio will be based on the Energy Bids provided by the SC.

(d) The ISO will notify each SC whose Schedule has been adjusted as to the adjustment in its Schedule.

SP 3.2.7 **[Not Used]**

SP 3.2.8 **[Not Used]**

SP 3.2.8.1 **[Not Used]**

SP 3.2.8.2 [Not Used]

SP 3.2.8.3 [Not Used]

SP 3.2.8.4 [Not Used]

SP 3.2.9 By 1:00 pm, Day Ahead

By 1:00 pm on the day ahead of the Trading Day (for example, by 1:00 pm on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day:

(a) the ISO will complete the operation of the integrated Day-Ahead Market;

(b) the ISO will provide, via WEnet, Final Day-Ahead Schedules to all SCs.

(c) the ISO will publish on OASIS the hourly Day-Ahead LMPs (in $/MWh of scheduled flow) for Energy;

(d) the ISO will provide, via WEnet, as part of the Final Day-Ahead Schedules, schedules for Ancillary Services to the SCs which either:

(i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or

(ii) submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO; and

(iii) specified Inter-Scheduling Coordinator Ancillary Service Trades which have been validated by the ISO; and

(e) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual SC intertie schedules will be examined. If the other Control Area's records are determined to be correct, the ISO will notify the affected SC. If the other Control Area Operator's records are in error, no changes will be required by the ISO or affected SCs. The affected SC is required to correct its schedule in the Hour-Ahead Market.

SP 3.2.10 Between 1:30 pm and 3:00 pm, Day Ahead

By 1:30 pm on the day ahead of the Trading Day (for example, by 1:30 pm on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day the ISO will publish, via OASIS, an updated forecast of system Demands.

The ISO shall run the Residual Unit Commitment Process to determine what if any additional Generators, System Resources, Dispatchable Loads and/or System Units need to be committed to meet the ISO Demand Forecast. The Residual Unit Commitment process will make use of all available bids in accordance with Section 5.12.2.

At 3:00 pm, the ISO shall transmit, via Wenet, notice to Scheduling Coordinators for all additional Generators, System Resources, Dispatchable Loads and/or System Units that are selected as a result of the Residual Unit Commitment Process. The ISO shall also transmit the quantity of committed capacity on each resource committed as a result of the Residual Unit Commitment Process.

SP 3.2.11 Between 1:00 p.m. and 10:00 p.m.

If, at any time after 1:00 p.m. and before 11:00 p.m. of the day prior to the Trading Day, the ISO determines that it requires Ancillary Services in addition to those provided through the Final Day-Ahead Schedules issued under SP 3.2.9, it may procure such additional Ancillary Services by providing to SCs, via WEnet, amended schedules for Ancillary Services that had been bid in the Day-Ahead Market but were not previously selected in the Final Day-Ahead Schedules, and have not been previously withdrawn. The ISO shall select such Ancillary Services in the relevant Ancillary Service Region if the ISO is procuring Ancillary Services on a regional basis. Such amended schedules shall be provided to the SCs no later than 11:00 p.m. of the day prior to the Trading Day.

SP 3.3 Hour-Ahead Market

(a) The Hour-Ahead Market is a "deviations" market in that it represents changes from the Day-Ahead Market commitments already made for each Settlement Period in the Trading Day. The SCs do not schedule these deviations. Instead, these deviations are calculated by the ISO as the difference between the Final Hour-Ahead Schedules (reflecting updated forecasts of Generation, Demand, external imports/exports and Inter-Scheduling Coordinator Energy Trades) and the Final Day-Ahead Schedules. If a SC does not submit a valid Preferred Hour-Ahead Schedule, its Final Day-Ahead Schedule will be deemed to be its Preferred Hour-Ahead Schedule.

(b) The Hour-Ahead Markets for each Settlement Period of each Trading Day open when the Day-Ahead Market commitments are made for the same Trading Day. Hour-Ahead Market commitments are made one hour ahead of the start of the applicable Settlement Period, at which time the ISO issues the Final Hour-Ahead Schedules. There is an option in the bid submittal process for a SC to submit a Schedule or bid for one Settlement Period of the Trading Day or a set of Schedules and bids for all Settlement Periods of the Trading Day (but only between 1:00 pm and 11:00 pm the day before).

(c) For each Hour-Ahead Market of the Trading Day the ISO's validation of SCs' contract usage templates, associated with Existing Contract rights or Firm Transmission Rights, will be performed. If a derate of a transmission Pathway has occurred which affects an SC's Final Day-Ahead Schedule or Ancillary Service commitments, the ISO will notify the SC, via the WEnet, of its available contract capacity. Additionally, the ISO will validate SCs' scheduled usage against SCs' contract usage templates and notify SCs of any invalidated usage. Such validations and notifications associated with contract usage, available contract capacities and invalidated contract usage will occur during the two hours prior to the ISO's deadline for receiving Preferred Hour-Ahead Schedules.

SP 3.3.1 By One Hour Ahead

By one hour ahead of the Settlement Period (for example, by 11:00 am for the Settlement Period starting at 12:00 noon [or hour ending 1300]) and with respect to that Settlement Period:

SP 3.3.1.1 Actions by SCs and the ISO

(a) SCs will submit their Preferred Hour-Ahead Schedules to the ISO in accordance with the SBP;

(b) SCs will submit, as part of their Preferred Hour-Ahead Schedules, their Energy Bids, if any, to the ISO in accordance with the SBP;

(c) SCs will submit their Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;

(d) SCs will submit their Schedules for self-provided Ancillary Services and Inter-Scheduling Coordinator Ancillary Service Trades, if any, to the ISO in accordance with the SBP and SP 9;

(e) the ISO will validate (in accordance with the SBP) all SC submitted Preferred Hour-Ahead Schedules for Energy and Energy Bids;

(f) SCs will submit contract usage templates for scheduled uses of Existing Contract Rights and Firm Transmission Rights in accordance with the Hour-Ahead Market schedule, including usage template changes needed in response to line derations;

(g) the ISO will validate (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights;

(h) the ISO will validate (in accordance with the SBP) all SC submitted Schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which were part of their Preferred Hour-Ahead Schedules;

(i) the ISO will validate that all SC submitted Preferred Hour-Ahead Schedules are compatible with the RMR requirements of which SCs were notified for that Trading Day and with the SCs' elected options for delivering the required Energy.

SP 3.3.1.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Preferred Hour-Ahead Schedules, Energy Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in the SBP. The purpose of this is to allow the SCs, particularly those involved in the Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of the pre-validation of each SC's submittal to that SC via WEnet.

SP 3.3.1.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal results in rejection of the submittal. SCs will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the SC's submittal; instead, invalid contract usage will be treated as New Firm Uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. SCs may check at any time prior to two hours ahead of the relevant Settlement Period whether or not their submittals will pass the ISO's validation checks (which are undertaken at one hour ahead of the Settlement Period). It is the responsibility of SCs to perform such checks since Preferred Hour-Ahead Schedules, Energy Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades and Ancillary Services bids which are invalidated cannot be resubmitted for the Hour-Ahead Market after one hour ahead of the relevant Settlement Period. The ISO will immediately communicate the results of each SC's one hour ahead validation to that SC via WEnet. If the usage or sum of the usages associated with an Existing Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the ETC rights will be considered a New Firm Use (NFU) and will be exposed to Congestion charges.

SP 3.3.2 By 45 minutes Ahead

By 45 minutes ahead of the Settlement Period (for example, by 11:15 am for the Settlement Period starting at 12:00 noon [or hour ending 1300]) and in respect of that Settlement Period:

(a) The ISO will use the SC's Final Day-Ahead Schedule, without any Day-Ahead Energy Bids or Day-Ahead Ancillary Service bids, in the event the SC's Preferred Hour-Ahead Schedule fails validation. If a SC desires to submit an Hour-Ahead Schedule that is different than its Final Day-Ahead Schedule the SC must submit the Hour-Ahead Schedule including the addition or removal of any resources (i.e., for those resources to be removed, a zero value for the hourly MW quantity) in its Final Day-Ahead Schedule that are to be added, or that are not to be included, in the Hour-Ahead Schedule. SCs may only remove resources with the ISO's approval as set forth in Section 2.3.1.2.1.

(b) the ISO will complete, if necessary, the Congestion Management process described in SP 10;

(c) the ISO will provide, via WEnet, Final Hour-Ahead Schedules for Energy to the ISO's real time dispatchers for use under the DP and to all SCs which could be:

(i) modified Preferred Hour-Ahead Schedules for those SCs which had their Preferred Hour-Ahead Schedules for Energy modified.

(d) the ISO will publish on OASIS the Hour-Ahead LMPs (in $/MWh)

(e) the ISO will provide, via WEnet, as part of the Final Hour-Ahead Schedules, schedules for Ancillary Services to the ISO's real time dispatchers for use under the DP and to the SCs which either:

(i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or

(ii) specified Inter-Scheduling Coordinator Ancillary Service Trades, or submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO.

(f) each SC will provide the ISO, via a form and by means of communication specified by the ISO, resource specific information for all Generating Units and Dispatchable Loads constituting its System Unit, if any, scheduled or bid into the ISO's Day-Ahead Market and/or Hour-Ahead Market for Ancillary Services.

(g) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual SC intertie schedules will be examined. If the other Control Area operator's records were in error, no changes will be required by the ISO or SCs. If the other Control Area operator's records are determined to be correct, the ISO will notify the affected SC. The ISO will manually adjust the affected SC's schedule to conform with the other Control Area operator's net schedule, in real time, and the affected SC will be responsible for managing any resulting Energy imbalance.

SP 3.3.3 Prior to the Beginning of The Settlement Period

Prior to the beginning of the Settlement Period, the ISO shall determine all pre-dispatch requirements for the upcoming Settlement Period as determined in accordance with 31.4.2. Such pre-dispatches shall be communicated to the responsible Scheduling Coordinator.

SP 4 TRANSMISSION SYSTEM LOSS MANAGEMENT

SP 4.1 Overview

(a) The ISO will reflect the marginal losses in the LMPs calculated by SCUC and SCED to account for the Energy lost in transmitting power from Generating Units and/or Scheduling Points to Load. Inter-Scheduling Coordinator Energy Trades will not be subject to such adjustments.

SP 4.2 **[Not Used]**

SP 4.2.1 **[Not Used]**

SP 4.2.2 **[Not Used]**

SP 4.3 **[Not Used]**

SP 5 RELIABILITY MUST-RUN GENERATION

SP 5.1 Procurement of Reliability Must-Run Generation by the ISO

SP 5.1.1 Annual Reliability Must-Run Forecast - Technical Evaluation

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

SP 5.1.2 Annual Reliability Must-Run Forecast - Technical Studies

The ISO will perform off-line technical studies, adopt existing procedures developed by PTOs and/or develop new operating procedures to identify the Reliability Must-Run requirements for various levels of system Demand.

SP 5.2 Designation of Generating Unit as Reliability Must-Run

The ISO will have the right at any time based upon ISO Controlled Grid technical analyses and studies to designate or disqualify a Generating Unit as a Reliability Must-Run Unit.

SP 5.3 Scheduling of Reliability Must-Run Generation

The ISO will notify SCs of any Reliability Must-Run Units which the ISO requires to run during a Trading Day no later than two hours before the deadline for submitting Day-Ahead Preferred Schedule for that Trading Day, as described in SP 3.2.1.1

SP 5.4 [UNUSED]

SP 6 [UNUSED]

SP 7 MANAGEMENT OF EXISTING CONTRACTS FOR TRANSMISSION SERVICE

SP 7.1 Obligations of Participating Transmission Owners and Scheduling Coordinators

SP 7.1.1 Participating Transmission Owners

Prior to the ISO accepting Schedules which include the use of Existing Rights, the Responsible PTO (as defined in the SBP) must have provided the ISO with the information required in the Transmission Control Agreement and the SBP, including transmission rights/curtailment instructions ("instructions") supplied in a form and by means of communication specified by the ISO.

SP 7.1.2 Scheduling Coordinators

The ISO will accept valid Schedules from a Responsible PTO that is the SC for the Existing Contract rights holders, or from Existing Contract rights holders that are SCs, or that are represented by a SC other than the Responsible PTO. Schedules submitted by SCs to the ISO which include the use of Existing Rights must be submitted in accordance with the SBP and this SP.

SP 7.2 Allocation of Forecasted Total Transfer Capabilities

SP 7.2.1 Categories of Transmission Capacity

As used in this SP, references to New Firm Uses shall mean any use of ISO transmission service, except for uses associated with Existing Rights. Prior to the start of the Day-Ahead scheduling process, for each significant WSCC rated path inside the ISO Control Area or interface with an external Control Area, the ISO will allocate the forecasted total transfer capability of the interface to three categories.

This allocation will represent the ISO's best estimates at the time, and is not intended to affect any rights provided under Existing Contracts, except as provided in SP 7.4. The ISO's forecast of total transfer capability for each interface will depend on prevailing conditions for the relevant Trading Day, including, but not limited to, the effects of parallel path (unscheduled) flows and/or other limiting operational conditions. This information will be posted on OASIS by the ISO in accordance with SP 3.2.1. In accordance with Section 2.4.4.5.1.4 of the ISO Tariff, the three categories are as follows:

(a) transmission capacity that must be reserved for firm Existing Rights;

(b) transmission capacity that may be allocated for use as ISO transmission service (i.e., "New Firm Uses");

(c) transmission capacity that may remain for any other uses, such as non-firm Existing Rights for which the Responsible PTO has no discretion over whether or not to provide such non-firm service.

SP 7.2.2 Prioritization of Transmission Uses

The following rules are designed to enable the ISO to honor Existing Contracts in accordance with Sections 2.4.3 and 2.4.4 of the ISO Tariff. Regardless of the success of the application of such rules, it is intended that the rights under Existing Contracts will be honored as contemplated by the ISO Tariff. In each of the categories described in SP 7.2.1, the terms and conditions of service may differ among transmission contracts. These differences will be described by each Responsible PTO in the instructions submitted to the ISO in advance of the scheduling process in accordance with the SBP. In addition, Generation or imports must be matched by an equal magnitude of Demand or exports (see SP 7.2.3 for a summary of allowable linkages). Scheduling and curtailment priorities associated with each category will be defined by SCs through the use of contract usage templates submitted as part of their Schedules as described in the SBP.

(a) Transmission capacity for Schedules will be made available to holders of firm Existing Rights in accordance with this SP and Section 9 of this Tariff and the terms and conditions of their Existing Contracts. In the event that the firm uses of these rights must be curtailed, they will be curtailed on the basis of priority expressed in contract usage templates. So as not to be curtailed before any other scheduled use of Congested capacity, the ISO's Congestion

Management software will assign a priority to such schedules consistent with Section 31.2.3.2.

(b) ISO transmission service (i.e., "New Firm Uses") will be priced in accordance with the ISO Tariff. LMPs associated with the ISO's Congestion Management procedures, as described in SP 10, will be based on Energy Bids. In the absence of an Energy Bid, the ISO will treat the scheduled "New Firm Use" of ISO transmission service as a Price Taker paying the difference in LMPs of the Scheduling Coordinators' Sources and Sinks.

(c) Transmission capacity will be made available to holders of conditional firm Existing Rights in a manner similar to that done prior to the ISO Operations Date; that is, allocated, as available, based on the agreed priority. The levels of priority will be expressed in the contract usage templates associated with the Schedules. To the extent that the MW amount in a schedule exceeds the MW amount specified in the contract usage template, the excess scheduled amount will be treated as a New Firm Use of ISO transmission services as described in (b) above. Note that, in some instances, there may be multiple SCs submitting Schedules under several different Existing Contracts on behalf of several Existing Contract rights holders. In these circumstances, and to the extent the rights holders desire to coordinate the prioritization of their conditional firm uses of the transmission, their SCs will make the arrangements among themselves ahead of the ISO's scheduling process. In the absence of a valid contract usage template associated with Existing Contract rights, the ISO will treat the scheduled use of transmission service as a "Price-Taker" of ISO transmission services subject to Usage Charges.

(d) Transmission capacity will be made available to holders of non-firm Existing Rights in a manner similar to that done prior to the ISO Operations Date; that is, treated as the lowest valued use of available transmission capacity.

SP 7.2.3 Allowable Linkages

As indicated in SP 7.2.2, Generation, or external imports must be matched by an equal magnitude of Demand, or external exports.

SP 7.3 The Day-Ahead Process

SP 7.3.1 Validation

The ISO will coordinate the scheduling of the use of Existing Rights with New Firm Uses in the Day-Ahead process. The ISO will validate the Schedules submitted by SCs on behalf of the rights holders for conformity with the instructions previously provided by the Responsible PTO in accordance with the SBP. Invalid Schedules will be rejected and the ISO will immediately communicate the results of each SC's validation to that SC via WEnet.

SP 7.3.2 Scheduling Deadlines

Those Existing Contract rights holders who must schedule the use of their rights by the deadline for the submission of Schedules in the Day-Ahead Market must do so. After this time, the ISO will release these unused rights as available for New Firm Uses (not subject to recall).

SP 7.3.3 Reservation of Firm Transmission Capacity

As an initial step in performing its Day-Ahead Congestion Management analysis, the ISO will determine the amount of transmission capacity that is available and subject to its Protocols by subtracting, from the total transfer capability of the transmission system the unused portions of capacity applicable to firm Existing Rights. For purposes of Congestion Management, the total transfer capability of the Pathway is therefore adjusted downward by an amount equal to the unused portions of firm Existing Rights. By reserving these blocks of unused transmission capacity, Existing Contracts rights holders are able to schedule the use of their transmission service on the timelines provided in their Existing Contracts after the deadline of the ISO's Day-Ahead scheduling process (in other words, after 1:00 pm on the day preceding the Trading Day), but prior to the deadline of the ISO's Hour-Ahead scheduling process (in other words, one hour ahead of the Settlement Period).

SP 7.3.4 Allocation of Pathway Capacities

In the ISO's Congestion Management analysis of the Day-Ahead Market, for each Pathway;

(a) if all scheduled uses of transmission service fit within the adjusted total transfer capability, all are accepted (in other words, there is no Congestion);

(b) if all scheduled uses of transmission service do not fit within the adjusted total transfer capability, scheduled uses of non-firm Existing Rights will be curtailed, pro rata, to the extent necessary. If the remaining scheduled uses of transmission service still do not fit within the adjusted total transfer capability, uses of conditional firm Existing Rights will be curtailed (based upon the levels of priority expressed in the contract usage templates for Schedules as described in SP 7.2.2 (c)) to the extent necessary;

(c) if Congestion still exists after curtailing all lower priority schedules (e.g. requesting non-firm and conditional firm uses of transmission service under Existing Contracts), the remaining transmission capacity (that is not already reserved as firm Existing Rights) is priced based upon Energy Bids. To the extent there are insufficient Energy Bids to fully mitigate the remaining Congestion, the default Usage Charge will apply and the ISO will curtail ISO transmission service (in other words, New Firm Uses other than Firm Transmission Rights uses evaluated in the Day-Ahead process), based on the effectiveness of the resource on relieving the Congestion to the extent necessary;

(d) If Congestion still exists after curtailing all New Firm Uses (other than Firm Transmission Rights uses) in the Day-Ahead scheduling process, scheduled uses of Firm Transmission Rights are then curtailed based on the effectiveness of the resource on relieving the Congestion to the extent necessary; and

(e) if Congestion still exists after curtailing ISO New Firm Uses and uses of Firm Transmission Rights, scheduled uses of firm Existing Rights are then curtailed (based upon the priorities expressed in the contract usage templates associated with the Schedules as described in SP 7.2.2 (a)) to the extent necessary.

SP 7.4 The Hour-Ahead Process

SP 7.4.1 Validation

The ISO will coordinate the scheduling of the use of Existing Rights with New Firm Uses, in the Hour-Ahead process. The ISO will validate the submitted Schedules for conformity with the instructions provided by the Responsible PTOs, in accordance with the SBP. Invalid schedules will be rejected and the ISO will immediately communicate the results of each SC's validation to that SC via WEnet.

SP 7.4.2 Scheduling Deadlines

Those rights holders who must schedule the use of their rights by the deadline for the submission of Schedules in the Hour-Ahead Market must do so. After this time, the ISO will release these unused rights as available for New Firm Uses (not subject to recall).

SP 7.4.3 Acceptance of Firm Transmission Schedules

Before allocating any remaining transmission capacity under the following provisions of this SP 7, the ISO will accept Schedules associated with firm Existing Rights (subject to validation under SP 7.4.1), allocating transmission capacity for use by these rights holders.

SP 7.4.4 Reservation of Firm Transmission Capacity

The ISO will adjust the total transfer capabilities of the Pathways with respect to firm Existing Rights as it does in its Day-Ahead process described in this SP 7.3.3. Therefore, holders of Existing Rights are still able to exercise whatever scheduling flexibility they may have under their Existing Contracts after the Schedules and bids submittal deadline of the ISO's Hour-Ahead scheduling process, as described further in SP 7.5.

SP 7.4.5 Allocation of Transmission Pathway

In the ISO's Congestion Management analysis of the Hour-Ahead Market, for each Pathway:

(a) if all scheduled uses of transmission service fit within the total transfer capability, all are accepted (in other words, there is no Congestion);

(b) if all scheduled uses of transmission service do not fit within the total transfer capability, scheduled uses of non-firm Existing Rights will be curtailed, based on the effectiveness of the resource on relieving the Congestion to the extent necessary. If the remaining scheduled uses of transmission service still do not fit within the total transfer capability, scheduled uses of conditional firm Existing Rights will be curtailed (based upon the levels of priority expressed in the contract usage templates for the Schedules as described in SP 7.2.2 (c)) to the extent necessary;

(c) if Congestion still exists after curtailing all lower priority schedules (e.g. representing non-firm and conditional firm uses of transmission service under Existing Contracts), the remaining transmission capacity (the subject of firm Existing Rights) is priced based upon Energy Bids. To the extent there are insufficient Energy Bids to fully mitigate the remaining Congestion, the default Usage Charge will apply and the ISO will curtail ISO transmission service (in other words, New Firm Uses including New Firm Uses of Firm Transmission Rights), based on the effectiveness of the resource on relieving the Congestion to the extent necessary; and

(d) if Congestion still exists after curtailing ISO New Firm Uses, scheduled uses of firm Existing Rights will be curtailed (based upon the priorities expressed in the contract usage template associated with the Schedules as described in SP 7.2.2 (a)) to the extent necessary.

SP 7.5 The ISO's Real-Time Process

Consistent with SP 7.4.4, the ISO will honor those scheduling flexibilities that may be exercised by holders of Existing Rights through their respective SCs during the ISO's real-time processes to the extent that such flexibilities do not interfere with or jeopardize the safe and reliable operation of the ISO Controlled Grid or Control Area operations. The real-time processes described in SP 7.5.1 and SP 7.5.2 will occur during the two hours following the ISO's receipt of Preferred Hour-Ahead Schedules (that is, from one hour ahead of the start of the Settlement Period through the end of such Settlement Period).

SP 7.5.1 Inter-Control Area Changes to Schedules that Rely on Existing Rights

Changes to Schedules that occur during the ISO's real-time processes that involve changes to ISO Control Area imports or exports with other Control Areas (that is, inter-Control Area changes to Schedules) will be allowed and will be recorded by the ISO based upon notification received from the SC representing the holder of the Existing Rights. The ISO must be notified of any such changes to external import/export schedules. The ISO will receive notification of real time changes to external import/export schedules, by telephone, from the SC representing the holder of the Existing Rights. The timing and content of any such notification must be consistent with the instructions previously submitted to the ISO by the Responsible PTO in accordance with the SBP. The ISO will manually adjust the SC's schedule to conform with the other Control Area's net schedule in real time, and the notifying SC will be responsible for and manage any resulting Energy imbalance. These Imbalance Energy deviations will be priced and accounted to the SC representing the holder of Existing Rights in accordance with the SABP.

SP 7.5.2 Intra-Control Area Changes to Schedules that Rely on Existing Rights

Changes to Schedules that occur during the ISO's real-time processes that do not involve changes to ISO Control Area imports or exports with other Control Areas (that is, intra-Control Area changes to Schedules) will be allowed and will give rise to Imbalance Energy deviations. These Imbalance Energy deviations will be priced and accounted to the SC representing the holder of Existing Rights in accordance with the SABP.

SP 8 OVERGENERATION MANAGEMENT

SP 8.1 Real Time Overgeneration Management

Overgeneration management in real time will be conducted in accordance with the DP.

SP 9 DAY/HOUR-AHEAD ANCILLARY SERVICES MANAGEMENT

SP 9.1 Bid Evaluation and Scheduling Principles

The ISO will evaluate Ancillary Services bids based on the following principles:

(a) the ISO will not differentiate between bidders other than through reserve (Regulation and Operating Reserves) price and capability to provide the reserve service, and the required regional dispersion of services;

(b) to minimize the costs to users of the ISO Controlled Grid, the ISO will select the bidders with the lowest total capacity bids and opportunity cost for reserve which meet its technical requirements, including regional requirement and operating capability;

(c) the ISO will (to the extent available) procure sufficient Ancillary Services to meet its technical requirements as defined in the ASRP;

(d) the ISO will evaluate and price the Ancillary Services bids received in accordance with the SBP and the default bids created in accordance with Section 31.2.3.2.3.5.1.4;

(e) the ISO will require SCs to honor their Day-Ahead Ancillary Services schedules and/or bids when submitting their Hour-Ahead Ancillary Services schedules and/or bids. A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve or Non-Spinning Reserve, capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, Dispatchable Load, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be at the maximum of the Day-Ahead and Hour-Ahead Ancillary Service Marginal Price in the Hour-Ahead Market for the same Settlement Period for the Ancillary Service capacity concerned. Increases in each Scheduling Coordinator's self-provided Ancillary Services between the Day-Ahead and Hour-Ahead Markets shall be limited to the estimated incremental Ancillary Service requirement associated with the increase between the Day-Ahead and Hour-Ahead Markets in that Scheduling Coordinator's scheduled Locational Load. Notwithstanding this limit on increases in Hour-Ahead self-provision, a Scheduling Coordinator may buy or sell Ancillary Services through Inter-Scheduling Coordinator Ancillary Service Trades in the Hour-Ahead Market;

(f) due to the design of the ISO's scheduling system, any specific resource can bid to supply a specific Ancillary Service or can self-provide such Ancillary Service but cannot do both in the same Settlement Period.

SP 9.2 Simultaneous Evaluation of Bids

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.

SP 9.3 Scheduling Ancillary Services Resources

(a) SCs are allowed to self-provide all or a portion of the following Ancillary Services to satisfy their obligations to the ISO:

(i) Regulation;

(ii) Spinning Reserve; and

(iii) Non-Spinning Reserve.

(b) The ISO will reduce the quantity of Ancillary Services it competitively procures by the corresponding amount of the Ancillary Services that SCs self-provide.

(c) The ISO shall prepare supplier schedules for Ancillary Services (both self-provided and purchased by the ISO) for the Day-Ahead Market and the Hour-Ahead Market.

(d) The Ancillary Services schedules shall contain the information set out in the SBP for each Settlement Period of the following Trading Day in the case of the Day-Ahead schedules or for a specific Settlement Period in the case of Hour-Ahead schedules.

(e) Once the ISO has given SCs notice of the Day-Ahead and Hour-Ahead schedules, these schedules represent binding commitments made in the reserve markets between the ISO and the SCs concerned. A Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent the Ancillary Service associated with a Generating Unit, Dispatchable Load, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replacement shall be the maximum of the Day-Ahead and Hour-Ahead Ancillary Service Marginal Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the region in which the Generating Unit or other resources on behalf of which the Scheduling Coordinator buys back the capacity, are located. The ISO will purchase the Ancillary Service concerned from another Scheduling

Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

(f) Any minimum Energy output associated with Regulation and Spinning Reserve services shall be the responsibility of the SC, as the ISO's auction does not compensate the SC for the minimum Energy output of its Generating Units or System Unit, if any, bidding to provide these services. Accordingly, the SCs shall adjust their Schedules to accommodate the minimum Energy outputs required by the Generating Units or System Units, if any, included in the Ancillary Services schedules.

(g) SCs providing one or more of the Ancillary Services cannot change the identification of the Generating Units System Units or external imports of System Resources, if any, or Dispatchable Load offered in the Day-Ahead Market, in the Hour-Ahead Market, or in the Real Time Market (except with respect to System Units, if any, in which case SCs are required to identify and disclose the resource specific information for all Generating Units and Dispatchable Load constituting the System Unit scheduled or bid into the ISO's Day-Ahead Market and Hour-Ahead Market as required in SP 3.3.2(e)).

SP 9.4 Ancillary Service Bid Evaluation and Pricing Terminology

Unless otherwise specifically described herein, the following terminology will apply:

$CapRes_{ijt}$	=	the Ancillary Service reserve reservation bid price (in $/MW).
$Cap_{ijt}max$	=	the maximum amount of reserve that can be scheduled by the ISO with respect to a SC's bid of that resource to supply Ancillary Services (in MW).
Cap_{ij}	=	that portion of an Ancillary Services bid (in MW), identified in the ISO's evaluation process, that may be used to meet the ISO's *Requirement* for a particular Ancillary Service ($Cap_{ijt} \leq Cap_{ijt}max$)
Requirement	=	the total amount of reserve that must be scheduled for a particular Ancillary Service required by the ISO in a Settlement Period (in MW).
i, j, t	=	Generating Unit i, Scheduling Coordinator j, Settlement Period t.

SP 9.5 Regulation Bid Evaluation and Pricing

SP 9.5.1 Regulation Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO will select Generating Units, System Units, and System Resources with the Regulation bids which minimize the sum of the total Regulation bids of the Generating Units, System Units, and System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Regulation bid must be greater than or equal to the required amount of Regulation; and

(ii) the amount of Regulation bid for each Generating Unit, System Unit, or System Resource must be less than or equal to that Generating Unit's, System Unit's, or System Resource's ramp rate times *Period* $_{minutes}$ where *Period* $_{minute}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes.

(b) The total Regulation bid for each Generating Unit, System Unit, or System Resource is calculated by multiplying the reserve reservation bid price by the sum of the amount of Regulation bid and an opportunity cost determined from the resource's Energy bid. Subject to any regional requirements, the ISO will accept winning Regulation bids in accordance with ISO Tariff Appendix K.

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

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

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

SP 9.5.2 Regulation Price Determination

The price payable to SCs for Regulation made available for upward and downward movement in accordance with the ISO's Ancillary Services schedules will, for each Generating Unit, System Unit, and System Resource concerned, be the regional Ancillary Service Marginal Price for Regulation calculated as follows:

$Pagc_{ijt} = ASMP_{xt}$

where:

the regional Ancillary Service Marginal Price ($ASMP_{xt}$) for Regulation is the marginal cost of reserving Regulation capacity from a Generating Unit, System Unit, or System Resource in that Ancillary Services Region based on the reservation bid price (i.e., $ASMP_{xt} = Max\ (CapRes_{ijt})$ in that Ancillary Services Region for Settlement Period t). In the absence of Regional Congestion, the regional Ancillary Service Marginal Prices will be equal.

SP 9.6 Spinning Reserves Bid Evaluation and Pricing

SP 9.6.1 Spinning Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO will select the Generating Units, System Units and external imports of System Resources with the Spinning Reserve bids which minimize the sum of the total Spinning Reserve bids of the Generating Units, System Units and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Spinning Reserve bid must be greater than or equal to the required amount of Spinning Reserve; and

(ii) the amount of Spinning Reserve bid for each Generating Unit, System Unit or external import of a System Resource must be less than or equal to that Generating Unit's, System Unit's ramp rate times 10 minutes.

(b) The total Spinning Reserve bid for each Generating Unit, System Unit or external import of a System Resource is calculated by multiplying the reserve reservation bid price by the sum of the amount of Spinning Reserve bid and an opportunity cost determined from the resource's Energy bid. Subject to any regional requirements, the ISO will select the winning Spinning Reserve bids in accordance with ISO Tariff Appendix K.

$$Min \sum_{i,j} Totalbid_{ijt}$$

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

SP 9.6.2 Spinning Reserves Price Determination

The price payable to SCs for Spinning Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit or external import of a System Resource concerned, be the regional Ancillary Service Marginal Price for Spinning Reserve calculated as follows:

$$Psp_{ijt} = ASMP_{xt}$$

where:

the regional Ancillary Service Marginal Price ($ASMP_{xt}$) for Spinning Reserve is the marginal cost of reserving Spinning reserve Generating Unit, System Unit or external import of a System Resource in that Ancillary Services Region based on the reservation bid price (i.e., $ASMP_{xt} = Max(CapRes_{ijt})$ in for Settlement Period t). In the absence of Inter-Regional Congestion, the regional ASMP will be equal.

SP 9.7 Non-Spinning Reserves Bid Evaluation and Pricing

SP 9.7.1 Non-Spinning Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Dispatchable Loads and external imports of System Resources with the Non-Spinning Reserve bids which minimize the sum of the total Non-Spinning Reserve bids of the Generating Units, System Units, Dispatchable Loads and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Non-Spinning Reserve bid must be greater than or equal to the required amount of Non-Spinning Reserve; and

(ii) the amount of Non-Spinning Reserve bid for each Generating Unit, System Unit, or Dispatchable Loads must be less than or equal to that Generating Unit's, System Unit's, or Dispatchable Load, or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 10 minutes and the time to synchronize in the case of a Generating Unit, or to interruption in the case of a Load.

(b) The total Non-Spinning Reserve bid for each Generating Unit, System Unit, Dispatchable Load or external import of a System Resource is calculated by multiplying the sum of the reserve reservation bid price and an opportunity cost determined from the resource's Energy bid where applicable by the amount of Non-Spinning Reserve bid. Subject to any locational requirements, the ISO will accept the winning Non-Spinning Reserve bids in accordance with ISO Tariff Appendix K.

$$Min \sum_{i,j} Totalbid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

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

SP 9.7.2 Non-Spinning Reserves Price Determination

The price payable to SCs for Non-Spinning Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit, Dispatchable Loads or external import of a System Resource concerned, be the regional Market Clearing Price for Non-Spinning Reserve calculated as follows:

$Pnonsp_{ijt} = ASMP_x$

where:

the regional Ancillary Service Marginal Price ($ASMP_{xt}$) for Non-Spinning Reserve is the marginal cost of reserving Non-Spinning reserve of a Generating Unit, System Unit, Dispatchable Load or external import of a System Resource in that Ancillary Service Region based on the reservation bid (i.e., $ASMP_{xt} = Max(CapRes_{ijt})$ in for Settlement Period t). In the absence of Regional Congestion, the regional ASMP will be equal.

SP 9.9 Existing Contracts – Ancillary Services Accountability

Certain Existing Contracts may have requirements for Ancillary Services which differ from the requirements of this SP 9. Each PTO will be responsible for recovering any deficits or crediting any surpluses associated with differences in assignment of Ancillary Services requirements, through its bilateral arrangements or its Transmission Owner's Tariff. The ISO will not undertake the settlement or billing of any such differences under any Existing Contract.

SP 10 DAY/HOUR-AHEAD INTER-ZONAL CONGESTION MANAGEMENT

SP 10.1 Congestion Management Assumptions

The Congestion Management process is based upon the following assumptions:

(a) Congestion Management will be performed as part of the simultaneous Energy and Ancillary Service markets and will make use of an AC optimal power flow (OPF) program that uses linear optimization techniques with active power (MW) controls only; and

(b) transmission capacity reserved under Existing Contracts will not be subject to the ISO's Congestion Management procedures.

SP 10.2 Congestion Management Process

(a) Congestion Management will involve adjusting Schedules to remove potential transmission security violations and Pathway constraints, minimizing the dispatch cost, as determined by the submitted Energy Bids that accompany the submitted Schedules. See the SBP for a general description of the use of Energy Bids to establish priorities.

(b) If Energy Bids are exhausted before Congestion is eliminated, the remaining Schedules will be adjusted based on default Energy Bids generated in accordance with Section 31.2.3.2.3.4.5 except for those uses of transmission service under Existing Contracts, which are curtailed in accordance with SP 7.3 and SP 7.4.

SP 10.3 Congestion Management Pricing

(a) The Energy Bids that the SCs submit constitute bids to manage Congestion.

(b) The ISO will determine the prices for the use of Congested Pathways using the Energy Bids. The ISO will collect Congestion Revenue from SCs for their Scheduled use of Congested Pathways. If Energy Bids are exhausted and Schedules are adjusted based on Default energy bids

(c) The ISO will rebate the Congestion Revenues collected through FTR holders. Point-To-Point Right FTR Holders shall be entitled to the difference in the Locational Marginal Prices (LMPs) between the Sink and the Source, multiplied by the awarded quantities at the Sink and Source. These Point-To-Point Rights may include multiple Sources and Sinks that have been aggregated into single Trading Hubs and are represented by a single price and quantity.

SP 11 REAL TIME ECONOMIC DISPATCH

SP 11.1 Sources of Imbalance Energy

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

(a) unused Energy Bids submitted to the Hour-Ahead Market;

(b) Energy bids associated with awarded Ancillary Services capacity; and

(c) Energy associated with capacity committed in the Residual Unit Commitment Process.

SP 11.2 Dispatching Energy Bids

The sources of Imbalance Energy described in SP 11.1 will be Dispatched in order to minimize the costs of imbalance energy subject to transmission and other resource constraints through the Security Constrained Economic Dispatch (SCED). SCED will also produce Locational Marginal Prices for Energy that reflect the marginal costs of Imbalance Energy at each Location in the ISO Controlled Grid. Dispatch of Imbalance Energy will be done without regard to the source of the Energy Bid except that Energy Bids associated with Spinning and Non-Spinning Reserve shall not be Dispatched stack during normal operating conditions if the capacity associated with such bids has been designated as available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency. In the event of an unplanned Outage, a Contingency or threatened or actual System Emergency, all Energy bids associated with Spinning and Non-Spinning Reserve may be Dispatched by SCED.

Where, in any Dispatch Interval, the highest decremental Energy Bid available is higher than the lowest available incremental Energy Bid, the SCED Software will eliminate the Price Overlap by actually dispatching for all those incremental and decremental bids which fall within the overlap.

References to incremental Energy Bids include references to Demand reduction bids, and for the purpose of applying this algorithm a reduction in Demand shall be treated as an equivalent increase in Generation.

SP 11.3 Use of the Imbalance Energy Bids

The Imbalance Energy Bids, as described in SP 11.2, can be used to supply Energy for:

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

(b) managing Congestion in real time;

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

(d) recovering Operating Reserves utilized in real time;

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

SP 12 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

any of which may submit comments and objections to the ISO within two weeks of the date of posting of the draft on the ISO Home Page.

SABP 2.3.4 Final Payments Calendar

No later than October 31st in each year, the ISO will publish pursuant to Section 11.24.1 of the ISO Tariff the final ISO Payments Calendar for the following calendar year, after considering the comments and objections received from Scheduling Coordinators, Black Start Generators, Participating TOs and Owners. The final ISO Payments Calendar will be posted on the ISO Home Page.

SABP 2.3.5 Update the Final Payments Calendar

If as a result of a tariff amendment approved by FERC the final ISO Payments Calendar developed in accordance with SABP 2.3.3 and 2.3.4 above is rendered inconsistent with the timing set forth in the tariff, the ISO shall update the final ISO Payments Calendar to make it consistent with the tariff as approved by FERC on the date on which the tariff amendment goes into effect. The ISO shall simultaneously send out a notice to market participants that the final ISO Payments Calendar has been revised.

SABP 2.3.6 Final Calendar Binding

The final ISO Payments Calendar shall be binding on the ISO and on Scheduling Coordinators, Black Start Generators, Participating TOs and Owners.

SABP 3 COMPUTATION OF CHARGES

SABP 3.1 Description of Charges to be Settled

The ISO shall, based on Final Day-Ahead and Hour-Ahead schedules, the Settlement Quality Meter Data it has received, or, if Settlement Quality Meter Data is not available, based on the best available information or estimate it has received, calculate the following:

(a) the amount due from each Scheduling Coordinator or other appropriate party for its share for the relevant month of the three components of the Grid Management Charge in accordance with Appendix A. These Charges shall accrue on a monthly basis.

(b) [Not Used]

(c) the amount due from and/or owed to each Scheduling Coordinator for the Charge for each Ancillary Service in accordance with Appendix C, for each of the Settlement Periods of Day 0.

(d) the amount due from and/or owed to each Scheduling Coordinator for Imbalance Energy in accordance with Tariff Section 31.4.3.4.4 and SABP Appendix D, for each of the Settlement Periods of Day 0.

(e) the amount due from and/or owed to each Scheduling Coordinator for Day-Ahead and/or Hour-Ahead Energy in accordance with Appendix E, for each of the Settlement Periods of Day 0.

(f) the amount due from each Scheduling Coordinator for Wheeling Out and Wheeling Through Charges and the amount owed to each Participating TO for these charges in accordance with Appendix F, for each of the Settlement Periods of Day 0.

(g) the amounts due from/to Scheduling Coordinators for Voltage Support (supplemental reactive power charges) for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(h) the monthly charges due from/to Scheduling Coordinators for long term voltage support provided by Owners of Reliability Must-Run Units in accordance with Appendix G.

(i) the amounts due from/to Scheduling Coordinators for the provision of Black Start Energy from Reliability Must-Run Units for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(j) the amounts due from/to Black Start Generators for the provision of Black Start Energy for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(k) the amount due from each UDC or MSS, or from a Scheduling Coordinator delivering Energy for the supply of Gross Load not directly connected to the facilities of a UDC or MSS, for the High Voltage Access Charge and Transition Charge in accordance with operating procedures posted on the ISO Home Page. These charges shall accrue on a monthly basis.

(l) the amounts due from Scheduling Coordinators for FERC Annual Charges.

(m) the payment or charges to FTR Holders associated with FTRs;

(n) the amount due to or from Scheduling Coordinators for the unrecovered costs associated with committing resources in the Day-Ahead and Hour-Ahead markets in accordance with Appendix H, for each of the Settlement Periods of Day 0.

(o) the amount due to or from Scheduling Coordinators for the capacity payments and unrecovered costs associated with committing resources in the Day-Ahead and Hour-Ahead Residual Unit Commitment in accordance with Section 31.4.3.4.4 and Appendix H, for each of the Settlement Periods of Day 0.

All of the data, information, and estimates the ISO uses to calculate these amounts shall be subject to the auditing requirements of Section 10.5 of the ISO Tariff.

The ISO shall calculate these amounts using the software referred to in SABP 2.1 except in cases of system breakdown when it shall apply the procedures set out in SABP 9 (Emergency Procedures).

SABP 3.1.1 Additional Charges and Payments

The ISO shall be authorized to levy additional charges or payments as special adjustments in regard to:

(a) amounts required to round up any invoice amount expressed in dollars and cents to the nearest whole dollar amount in order to clear the ISO Clearing Account. These charges will be allocated amongst Scheduling Coordinators over an interval determined by the ISO and pro rata based on metered Demand (including exports) during that interval;

(b) amounts in respect of penalties which may be levied by the ISO in accordance with the ISO Tariff. These charges will be levied on the Market Participants liable for payment of the penalty; and

(c) amounts required to reach an accounting trial balance of zero in the course of the Settlement process in the event that the charges calculated as due from ISO Debtors are lower

APPENDIX B

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APPENDIX C

SETTLEMENT OF ANCILLARY SERVICES

C.1. General Information

For each operating hour, the ISO must ensure that there are sufficient Ancillary Services available to maintain the reliability of the ISO Controlled Grid consistent with WSCC and NERC criteria. ISO Ancillary Services include Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve. Each of these services is settled separately.

C.1.1. Terms

Any reference to the term "Regulation" as used in Appendix C shall be read as referring to "Regulation Up" or "Regulation Down".

The term "Region" or "Regional" as used in Appendix C shall refer to the "Ancillary Service Region" as defined in the Master Definitions Supplement, Appendix A.

The term "Metered Demand" as used in Appendix C shall refer to metered load and real-time exports.

Ancillary Service Self-Provision

Scheduling Coordinators may chose to self-provide Ancillary Services to (i) reduce their own Net Ancillary Service Obligation and (ii) use the Excess Self-Provision to reduce other SC's Net Ancillary Service Obligation if such Excess Self-Provisions are Qualified.

Gross Ancillary Service Obligation

The Gross Ancillary Service Obligation for each service for each hour for each Scheduling Coordinator is the amount of Ancillary Services that it needs to secure either by self-provision or by ISO-provision. Each Scheduling Coordinator's obligation to pay Ancillary Service charges is based on metered demand adjusted for on-demand obligation and Inter-SC Ancillary Services trades.

Gross Ancillary Service Requirement

The Gross Ancillary Service Requirement for each service for each hour in each region in each of the market, i.e. the Day-Ahead Market and the Hour-Ahead Market, is the amount of capacity that needs to be secured by the ISO either through procurement or self-provision.

Net Ancillary Service Obligation

The Net Ancillary Service Obligation for each service for each hour for each Scheduling Coordinator is its Gross Ancillary Service Obligation minus the amount of Self-Provision accepted by the ISO in the Day-Ahead or the Hour-Ahead Market. The Net Ancillary Service Obligation is the basis for billing a given Ancillary Service.

Net Ancillary Service Requirement

The Net Ancillary Service Requirement for each Ancillary Service for each hour in each region in each market is the Gross Ancillary Service Requirement minus Qualified Ancilary Service Self-Provision.

Qualified Ancillary Service Self-Provision

Qualified Ancillary Service Self-Provision is the amount of self-provision that has been used to reduce the ISO's Gross Ancillary Service Requirement. In other words, it has been used to determine the Net Ancillary Service Requirement in either the Day-Ahead Market or the Hour-Ahead Market.

Qualified Excess Ancillary Service Self-Provision

The amount of self-provision that exceeds the Gross Ancillary Service Obligation of the Scheduling Coordinator is referred to as Excess Ancillary Service Self-Provision. Qualified Excess Ancillary Services Self-Provision will be compensed if it is used by the ISO to reduce the Gross Ancillary Service Requirement.

C.1.2. Payments

The ISO will purchase Ancillary Services for each Settlement Period in both the Day-Ahead and Hour-Ahead Markets. Separate payments will be calculated for each service for each Settlement Period and in each market for each resource providing Ancillary Services. The prices used to determine the payments are the Ancillary Service Marginal Prices, as determined by SCUC. The SCUC prices reflect a simultaneous procurement of Energy and Ancillary Services at least cost and take into account the substitutability of services.

C.1.3. Charges

The Ancillary Service Charges allocate the costs of purchasing Ancillary Services in the Day-Ahead and Hour-Ahead Markets to Scheduling Coordinators according to their share of the metered Load (for Regulation) or metered Demand (for Spinning and Non-Spinning Reserves).

Scheduling Coordinators shall be paid for their Qualifiied Excess Ancillary Services Self-Provision.

The user rates that are used in calculating Ancillary Service charges are based on the cost of meeting each Ancillary Service requirement.

C.1.4. Neutrality

Due to the difference between the basis for payment and charge of Ancillary Services, there is a need for a neutrality adjustment. Specifically, payment for the procurement of Ancillary Services is based on the ISO Demand Forecast, whereas the charge methodology is based on Metered Demand. Since the ISO Demand Forecast may be different than Metered Demand, there will be a difference, in total, between the two calculations and a need for a neutrality adjustment. The neutrality imbalance for each Ancillary Service will be allocated to all Scheduling Coordinators based on Demand (for Regulation) or Demand (for Spinning and Non-Spinning Reserve service.)

C.2. Fundamental Formulas

C.2.1. ISO Payments to Scheduling Coordinators

C.2.1.1. Day-Ahead Market

C.2.1.1.1. Regulation

When the ISO purchases Regulation in the Day-Ahead Market, Scheduling Coordinators for Generating Units, System Units, and System Resources that provide this capacity will receive payments for each Settlement Period of the Day-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over a given Settlement Period will be the total quantity of Regulation capacity provided times the applicable Ancillary Service Marginal Price for that Settlement Period in that Ancillary Service Region. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. Regulation Up and Regulation Down payments shall be calculated separately. The payment for Scheduling Coordinator j for providing Regulation Up capacity from resource i in Ancillary Service Region x for Settlement Period t is calculated as follows:

$$AGCUpPayDA_{ijxt} = AGCUpQDA_{ijxt} \times PAGCUpDA_{jxt} - AGCUpCCDA_{ijxt}$$

where $AGCUpCCDA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator j for Regulation Up in the Day-Ahead Market from resource i at Scheduling Point x in Settlement Period t, calculated as follows:

$$AGCUpCCDA_{ijxt} = AGCUpQDA_{ijxt} \times PCCDA_{xt}$$

This Congestion Charge is booked as receivable in the FTR balancing account as Congestion Revenue.

The payment for Scheduling Coordinator j for providing Regulation Down capacity from resource i in Ancillary Service Region x for Settlement Period t is calculated as follows:

$$AGCDownPayDA_{ijxt} = AGCDownQDA_{ijxt} \times PAGCDownDA_{xt}$$

The total Regulation Up payment to each Scheduling Coordinator for a given Settlement Period in the Day-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period. The payment for Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t is calculated as follows:

$$AGCUpPayTotalDA_{jxt} = \sum_{i} AGCUpPayDA_{ijxt}$$

The total Regulation Down payment to each Scheduling Coordinator for a given Settlement Period in the Day-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCDownPayTotalDA_{jxt} = \sum_{i} AGCDownPayDA_{ijxt}$$

C.2.1.1.2. Spinning Reserve

When ISO purchases Spinning Reserve in the Day-Ahead Market, Scheduling Coordinators for Generating Units, System Units, and System Resources that provide this capacity will receive payments for each Settlement Period of the Day-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over a given Settlement Period will be the total quantity of Spinning Reserve capacity provided times the applicable Ancillary Service Marginal Price adjusted for Congestion Charges on interties if applicable for that Settlement Period in that Ancillary Service Region. The required Spinning Reserve capacity is defined in the Ancillary Services Requirements Protocol. The payment for Scheduling Coordinator *j* for providing Spinning Reserve from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$SpinPayDA_{ijxt} = SpinQDA_{ijxt} \times PSpinDA_{xt} - SpinCCDA_{ijxt}$$

where $SpinCCDA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for Spinning Reserve in the Day-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$$SpinCCDA_{xt} = SpinQDA_{ijxt} \times PCCDA_{xt}$$

This Congestion Charge is booked as receivable in the FTR balancing account as Congestion Revenue.

The total Spinning Reserve payment to each Scheduling Coordinator for a given Settlement Period in the Day-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$SpinPayTotalDA_{jxt} = \sum_{i} SpinPayDA_{ijxt}$$

C.2.1.1.3. Non-Spinning Reserve

When the ISO purchases Non-Spinning Reserve in the Day-Ahead Market, Scheduling Coordinators for Generating Units, System Units, Dispatchable Loads, and System Resources that provide this capacity will receive payments for each Settlement Period of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over a given Settlement Period will be the total quantity of Non-Spinning Reserve capacity provided times the applicable Ancillary Service Marginal Price adjusted for Congestion Charges on interties if applicable for that Settlement Period in that Ancillary Service Region. The required Non-Spinning Reserve capacity is defined in the Ancillary Services Requirements Protocol. The payment for Scheduling Coordinator *j* for providing Non-Spinning Reserve capacity from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$NonSpinPayDA_{ijxt} = NonSpinQDA_{ijxt} \times PNonSpinDA_{xt} - NonSpinCCDA_{ijxt}$$

where $NonSpinCCDA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for Non-Spinning Reserve in the Day-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$$NonSpinCCDA_{ijxt} = NonSpinQDA_{ijxt} \times PCCDA_{xt}$$

This Congestion Charge is booked as a receivable in the FTR Balancing Account as Congestion Revenue.

The total Non-Spinning Reserve payment to each Scheduling Coordinator for a given Settlement Period in the Day-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$NonSpinPayTotalDA_{jxt} = \sum_i NonSpinPayDA_{ijxt}$$

C 2.1.2. Hour-Ahead Market

C.2.1.1.4. Regulation

When the ISO purchases Regulation in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, System Units, and System Resources that provide this capacity will receive payment for the Settlement Period of the Hour-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over the Settlement Period will be the total quantity of Regulation capacity provided times the applicable Ancillary Service Marginal Price for that Settlement Period in that Ancillary Service Region. The required Regulation capacity is defined in the Ancillary Services Requirements Protocol. Regulation Up and Regulation Down payments shall be calculated separately. The payment for Scheduling Coordinator *j* for providing Regulation Up capacity from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCUpPayHA_{ijxt} = AGCUpQIHA_{ijxt} \times PAGCUpHA_{xt} - AGCUpCCHA_{ijxt}$$

where $AGCUpCCHA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for Regulation Up in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$$AGCUpCCHA_{ijxt} = AGCUpQIHA_{ijxt} \times PCCHA_{xt}$$

This Congestion Charge is booked as receivable in the FTR balancing account as Congestion Revenue.

The payment for Scheduling Coordinator *j* for providing Regulation Down from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCDownPayHA_{ijxt} = AGCDownQIHA_{ijxt} \times PAGCDownHA_{xt}$$

When a Scheduling Coordinator buys back, in the Hour-Ahead Market, Regulation capacity which it sold or self-provided to the ISO in the Day-Ahead Market, the buy-back charge will be the total quantity of Regulation capacity bought back times the greater of the Day-Ahead Ancillary Service Marginal Price and the Hour-Ahead Ancillary Service Marginal Price as applicable for that Settlement Period in that Ancillary Service Region. The payment to the ISO from Scheduling Coordinator *j* to buy back Regulation Up from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCUpReceiveHA_{ijxt} = AGCUpQDHA_{ijxt} \times \max(PAGCUpDA_{xt}, PAGCUpHA_{xt}) - AGCUpCPHA_{ijxt}$$

where $AGCUpCPHA_{ijxt}$ is the Congestion Payment to Scheduling Coordinator *j* for Regulation Up in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$$AGCUpCPHA_{ijxt} = AGCUpQDHA_{ijxt} \times PCCHA_{xt}$$

This Congestion payment is credited to the FTR Balancing Account as Congestion Revenue.

The payment to the ISO from Scheduling Coordinator *j* to buy back Regulation Down from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCDownReceiveHA_{ijxt} = AGCDownQDHA_{ijxt} \times \max(PAGCDownDA_{xt}, PAGCDownHA_{xt})$$

The total Regulation payment for the Settlement Period of the Hour-Ahead Market to each Scheduling Coordinator for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Regulation bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Settlement Period on behalf of resources located in the Ancillary Service Region.

The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCUpPayTotalHA_{jxt} = \sum_i AGCUpPayHA_{ijxt} - \sum_i AGCUp\,\mathrm{Re}\,ceiveHA_{ijxt}$$

$$AGCDownPayTotalHA_{jxt} = \sum_i AGCDownPayHA_{ijxt} - \sum_i AGCDown\,\mathrm{Re}\,ceiveHA_{ijxt}$$

C.2.1.1.5. Spinning Reserve

When the ISO purchases Spinning Reserve in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, System Units, and System Resources that provide this capacity will receive payments for the Settlement Period of the Hour-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over the Settlement Period will be the total quantity of Spinning Reserve capacity provided times the applicable Ancillary Service Marginal Price adjusted for Congestion Charges on interties if applicable for that Settlement Period in that Ancillary Service Region. The payment for Scheduling Coordinator *j* for providing Spinning Reserve capacity from resource i in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$SpinPayHA_{ijxt} = SpinQIHA_{ijxt} \times PSpinHA_{xt} - SpinCCHA_{ijxt}$$

where $SpinCCHA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for Spinning Reserve in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$$SpinCCHA_{ijxt} = SpinQIHA_{ijxt} \times PCCHA_{xt}$$

This Congestion Charge is booked as a receivable in the FTR Balancing Account as Congestion Revenue.

When a Scheduling Coordinator buys back in the Hour-Ahead Market Spinning Reserve which it sold or self-provided to the ISO in the Day-Ahead Market, the buy-back charge will be the total quantity of Spinning Reserve capacity bought back times the greater of the Regional Day-Ahead Ancillary Service Marginal Price and the Regional Hour-Ahead Ancillary Service Marginal Price as applicable for that Settlement Period in that Ancillary Service Region. The payment to the ISO from Scheduling Coordinator *j* to buy back Spinning Reserve from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$SpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} \times \max(PSpinDA_{xy}, PSpinHA_{xt}) - SpinCPHA_{ijxt}$$

where $SpinCPHA_{ijxt}$ is the Congestion Payment to Scheduling Coordinator *j* for Spinning Reserve in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$$SpinCPHA_{ijxt} = SpinQDHA_{ijxt} \times PCCHA_{xt}$$

This Congestion payment is credited to the FTR Balancing Account as Congestion Revenue.

The total Spinning Reserve payment to each Scheduling Coordinator for the Settlement Period of the Hour-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Settlement Period on behalf of resources located in the Ancillary Service Region. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$SpinPayTotalHA_{jxt} = \sum_i SpinPayHA_{ijxt} - \sum_i Spin\,\mathrm{Re}\,ceiveHA_{ijxt}$$

C.2.1.1.6. Non-Spinning Reserve

When the ISO purchases Non-Spinning Reserve in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, System Units, Dispatchable Loads, and System Resources that provide this capacity will receive payment for the Settlement Period of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over the Settlement Period will be the total quantity of Non-Spinning Reserve capacity provided times the applicable Ancillary Service Marginal Price adjusted for Congestion Charges on interties if applicable for that Settlement Period in that Ancillary Service Region. This payment for Scheduling Coordinator *j* for providing Non-Spinning Reserve capacity from a resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$NonSpinPayHA_{ijxt} = NonSpinQIHA_{ijxt} \times PNonSpinHA_{xt} - NonSpinCCHA_{ijxt}$$

where $NonSpinCCHA_{ijxt}$ is the Congestion Charge to Scheduling Coordinator *j* for providing Non-Spinning Reserve in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$$NonSpinCCHA_{ijxt} = NonSpinQIHA_{ijxt} \times PCCHA_{xt}$$

This Congestion Charge is booked as a receivable in the FTR Balancing Account as Congestion Revenue.

When a Scheduling Coordinator buys back in the Hour-Ahead Market Non-Spinning Reserve which it sold or self-provided to the ISO in the Day-Ahead Market, the buy-back charge will be the total quantity of Non-Spinning Reserve capacity bought back times the greater of the Regional Day-Ahead Ancillary Service Marginal Price and the Regional

Hour-Ahead Ancillary Service Marginal Price as applicable for that Settlement Period in that Ancillary Service Region.

This payment to the ISO from Scheduling Coordinator *j* to buy back Non-Spinning Reserve from resource *i* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$NonSpinReceiveHA_{ijxt} = NonSpinQDHA_{ijxt} \times \max(PNonSpinDA_{xy}, PNonSpinHA_{xt}) - NonSpinCPHA_{ijxt}$

where $NonSpinCPHA_{ijxt}$ is the Congestion Payment to Scheduling Coordinator *j* for Non-Spinning Reserve in the Hour-Ahead Market from resource *i* at Scheduling Point *x* in Settlement Period *t*, calculated as follows:

$NonSpinCPHA_{ijxt} = NonSpinQDHA_{ijxt} \times PCCHA_{xt}$

This Congestion payment is credited to the FTR Balancing Account as Congestion Revenue.

The total Non-Spinning Reserve payment to each Scheduling Coordinator for the Settlement Period of the Hour-Ahead Market for all the resources that it represents in a given Ancillary Service Region is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Ancillary Service Region for the Settlement Period and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Non-Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Settlement Period on behalf of resources located in the Ancillary Service Region. The payment for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$NonSpinPayTotalHA_{jxt} = \sum_i NonSpinPayHA_{ijxt} - \sum_i NonSpin\text{Re}\,ceiveHA_{ijxt}$$

C.2.2. ISO Allocation of Charges toScheduling Coordinators

C.2.2.1. Regulation Up

The ISO will charge the total cost of procuring Regulation in the Day-Ahead and Hour-Ahead Markets, through the application of a charge to each Scheduling Coordinator for each Settlement Period at the ISO Control Area level. This charge will be computed by multiplying the Regulation user rate for the Settlement Period by the Scheduling Coordinator's Net Regulation Obligation for the same period.

The Regulation user rate is calculated by dividing the total procurement cost for the Net Regulation Capacity Requirement in all Ancillary Service Regions, for the Settlement Period, by the total Net Regulation Requirement for the Settlement Period in all Ancillary Service Regions. Regulation Up and Regulation Down payments shall be calculated separately.

The Regulation Up user rate for Settlement Period t is calculated as follows:

$$AGCUpRate_t = \frac{AGCUpPayNetReqDA_t + AGCUpPayNetReqHA_t}{AGCUpNetReqDA_t + AGCUpNetReqHA_t}$$

where $AGCUpNetReqDA_t$ is the Net Regulation Up Requirement for the Settlement Period *t* in the Day-Ahead Market for the ISO Control Area. It is the sum of all the Regional Net Regulation Up Requirement in the Day-Ahead Market as follows:

$$AGCUpNetReqDA_t = \sum_y AGCUpNetReqDA_{yt}$$

$AGCUpPayNetReqDA_t$ is the cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period *t* incurred in the Day-Ahead Market in all the Regions. It is calculated as follows:

$$AGCUpPayNetReqDA_t = \sum_y AGCUpPayNetReqDA_{yt}$$

$AGCUpPayNetReqDA_{yt}$ is the cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Day-Ahead Market in Region *y*. It is calculated as follows:

$$AGCUpPayNetReqDA_{yt} = AGCUpNetReqDA_{yt} \times PAGCUpDA_{yt}$$

where:

$AGCUpNetReqDA_{yt}$ is the Net Regulation Up Requirement for the Settlement Period t in the Day-Ahead Market for Region y.

$PAGCUpDA_{yt}$ is the Ancillary Service Marginal Price for Regulation Up for the Settlement Period *t* incurred in the Day-Ahead Market for Region *y*.

$AGCUpNetReqHA_t$ is the Net Regulation Up Requirement for the Settlement Period *t* in the Hour-Ahead Market for all the Regions. It is the sum of all the Regional Net Regulation Up Requirement as follows:

$$AGCUpNetReqHA_t = \sum_z AGCUpNetReqHA_{zt}$$

$AGCUpPayNetReqHA_t$ is the cost of Regulation Up procurement to meet net Regulation Up Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market in all the Regions. It is calculated as follows:

$$AGCUpPayNetReqHA_t = \sum_z AGCUpPayNetReqHA_{zt}$$

$AGCUpPayNetReqHA_{zt}$ is the cost of Regulation Up procurement to meet net Regulation Up Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market in Region *z*. It is calculated as follows:

$$AGCUpPayNetReqDA_{zt} = AGCUpNetReqHA_{zt} \times PAGCUpHA_{zt} - AGCUpReceiveHA_{zt}$$

where:

$AGCUpNetReqHA_{zt}$ is the total incremental Net Requirement of Regulation Up for the Settlement Period *t* in the Hour-Ahead Market for Region *z*.

$PAGCUpHA_{zt}$ is the Ancillary Service Marginal Price for Regulation Up for the Settlement Period *t* incurred in the Hour-Ahead Market for Region *z*.

$AGCUpReceiveHA_{zt}$ is the Total charges for Hour-Ahead Buyback of Regulation Up for the Settlement Period t for Region z.

The Regulation Up charge for Scheduling Coordinator *j* for Settlement Period *t* is calculated as follows:

$$AGCUpChg_{jt} = AGCUpNetOblig_{jt} \times AGCUpRate_{t}$$

$AGCUpNetOblig_{jt}$ is the Net Regulation Up Obligation for Scheduling Coordinator *j* for Settlement Period *t*. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Regulation Up.

$$AGCUpNetOblig_{jt} = AGCUpGrossOblig_{jt} - AGCUpQualifySelf_{jt}$$

where:

$AGCUpGrossOblig_{jt}$ is the gross Regulation Up Obligation for Scheduling Coordinator *j* for Settlement Period *t*.

$AGCUpQualifySelf_{jt}$ is the Qualified Self-Provision of Regulation Up for Scheduling Coordinator *j* for Settlement Period *t*.

$$AGCUpQualifySelf_{jt} = AGCUpQualifySelfDA_{jt} + AGCUpQualifySelfHA_{jt}$$

$AGCUpQualifySelfDA_{jt}$ = The Qualified Day-Ahead Self-Provision of Regulation Up for Scheduling Coordinator *j* for Settlement Period *t*.

$$AGCUpQualifySelfDA_{jt} = \sum_{y} AGCUpQualifySelfDA_{jyt}$$

$AGCUpQualifySelfHA_{jt}$ = The Qualified Hour-Ahead Self-Provision of Regulation Up for Scheduling Coordinator *j* for Settlement Period *t*.

$$AGCUpQualifySelfHA_{jt} = \sum_{z} AGCUpQualifySelfHA_{jzt}$$

where

$AGCUpQualifySelfDA_{jyt}$ is the Qualified Day-Ahead Self-Provision of Regulation Up for Scheduling Coordinator *j* in Region *y* for Settlement Period *t*.

$AGCUpQualifySelfHA_{jzt}$ is the Qualified Hour-Ahead Self-Provision of Regulation Up for Scheduling Coordinator *j* in Region *z* for Settlement Period *t*.

The ISO will charge each Scheduling Coordinator a Regulation Up Neutrality Adjustment Charge for each Settlement Period according to Demand.

$$AGCUpNeutraAdjChg_{jt} = MeteredLoad_{jt} \times AGCUpNeutraAdjRate_t$$

where:

$AGCUpNeutraAdjChg_{jt}$ is the Regulation Up Neutrality Adjustment Charge to Scheduling Coordinator *j* for Settlement Period *t*.

$MeteredLoad_{jt}$ is the Demand of Scheduling Coordinator *j* for Settlement Period *t*.

$AGCUpNeutraAdjRate_t$ is the Regulation Up Neutrality Adjustment Rate for Settlement Period *t*. The rate is the difference between the total amount of charge and the total amount of payment for the service divided by the total Demand of the ISO control area as follows.

$$AGCUpNeutraAdjRate_t = \frac{AGCUpChgTotal_t - AGCUpPayTotal_t - AGCUpCCTotal_t}{MeteredLoadTotal_t}$$

where:

$AGCUpChgTotal_t$ is the total amount of charges collected by the ISO from Scheduling Coordinators for provision of Regulation Up Service for the Settlement Period *t*.

$$AGCUpChgTotal_t = \sum_j AGCUpChg_{jt}$$

$AGCUpPayTotal_t$ is the total amount of payment from the ISO to Scheduling Coordinators for procuring Regulation Up Service for the Settlement Period *t* in both the Day-Ahead and the Hour-Ahead Markets.

$$AGCUpPayTotal_t = \sum_j \sum_x \left(AGCUpPayTotalDA_{jxt} + AGCUpPayTotalHA_{jxt}\right)$$

$AGCUpCCTotal_t$ is the total amount of Congestion charge incurred to the ISO for procuring Regulation Up over Congested interties for Settlement Period *t*. This amount shall be transferred into the FTR Balancing Account to balance the Congestion charge receivables booked in the Day-Ahead Market and the Hour-Ahead Market when Regulation Up is procured.

$$AGCUpCCTotal_t = \sum_j \sum_x \sum_i AGCUpCCDA_{ijxt} + \sum_j \sum_x \sum_i \left(AGCUpCCHA_{ijxt} - AGCUpCPHA_{ijxt}\right)$$

C.2.2.2. Regulation Down

The Regulation Down user rate in Ancillary Service Region *x* for Settlement Period *t* is calculated as follows:

$$AGCDownRate_t = \frac{AGCDownPayNetReqDA_t + AGCDownPayNetReqHA_t}{AGCDownNetReqDA_t + AGCDownNetReqHA_t}$$

where:

$AGCUpNetReqDA_t$ is the Net Regulation Down Requirement for the Settlement Period *t* in the Day-Ahead Market. It is the sum of all the Regional Net Regulation Down Requirement as follows:

$$AGCDownNetReqDA_t = \sum_y AGCDownNetReqDA_{yt}$$

$AGCDownPayNetReqDA_t$ is the cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period *t* incurred in the Day-Ahead Market. It is calculated as follows:

$$AGCDownPayNetReqDA_t = \sum_y AGCDownPayNetReqDA_{yt}$$

$AGCDownPayNetReqDA_{yt}$ is the cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period *t* incurred in the Day-Ahead Market in Region *y*. It is calculated as follows:

$$AGCDownPayNet\,\mathrm{Re}\,qDA_{yt} = AGCDownNet\,\mathrm{Re}\,qDA_{yt} \times PAGCDownDA_{yt}$$

where:

$AGCDownNetReqDA_{yt}$ is the Net Regulation Down Requirement for the Settlement Period *t* in the Day-Ahead Market for Region *y*.

$PAGCDownDA_{yt}$ is the Ancillary Service Marginal Price for Regulation Down for the Settlement Period *t* incurred in the Day-Ahead Market for Region *y*.

$AGCDownNetReqHA_t$ is the Net Regulation Down Requirement for the Settlement Period *t* in the Hour-Ahead Market. It is the sum of all the Regional Net Regulation Down Requirement as follows:

$$AGCDownNetReqHA_t = \sum_z AGCDownNetReqHA_{zt}$$

$AGCDownPayNetReqHA_t$ is the cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market. It is calculated as follows:

$$AGCDownPayNetReqHA_t = \sum_z AGCDownPayNetReqHA_{zt}$$

$AGCDownPayNetReqHA_{zt}$ is the cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market in Region *z*. It is calculated as follows:

$$AGCDownPayNet\mathrm{Re}\,qDA_{zt} = AGCDownNet\mathrm{Re}\,qHA_{zt} \times PAGCDownHA_{zt} - AGCDown\mathrm{Re}\,ceiveHA_{zt}$$

where:

$AGCDownNetReqHA_{zt}$ is the total incremental Net Requirement of Regulation Down for the Settlement Period *t* in the Hour-Ahead Market for Region *z*.

$PAGCDownHA_{zt}$ is the Ancillary Service Marginal Price for Regulation Down for the Settlement Period *t* incurred in the Hour-Ahead Market for Region *z*.

$AGCDownReceiveHA_{zt}$ is the total charges for Hour-Ahead Buyback of Regulation Down for the Settlement Period *t* for Region *z*.

The Regulation Down capacity charge for Scheduling Coordinator *j* for Settlement Period *t* is calculated as follows:

$$AGCDownChg_{jt} = AGCDownNetOblig_{jt} \times AGCDownRate_t$$

$AGCDownNetOblig_{jt}$ is the The Net Regulation Down Obligation for Scheduling Coordinator j for Settlement Period *t*. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Regulation Down.

$$AGCDownNetOblig_{jt} = AGCDownGrossOblig_{jt} - AGCDownQualifySelf_{jt}$$

where:

$AGCDownGrossOblig_{jt}$ is the The Gross Regulation Down Obligation for Scheduling Coordinator *j* for Settlement Period *t*.

$AGCDownQualifySelf_{jt}$ is the The Qualified Self-Provision of Regulation Down for Scheduling Coordinator *j* for Settlement Period *t*.

$$AGCDownQualifySelf_{jt} = AGCDownQualifySelfDA_{jt} + AGCDownQualifySelfHA_{jt}$$

$AGCDownQualifySelfDA_{jt}$ is the The Qualified Day-Ahead Self-Provision of Regulation Down for Scheduling Coordinator *j* for Settlement Period *t*.

$$AGCDownQualifySelfDA_{jt} = \sum_{y} AGCDownQualifySelfDA_{jyt}$$

$AGCDownQualifySelfHA_{jt}$ is the The Qualified Hour-Ahead Self-Provision of Regulation Down for Scheduling Coordinator *j* for Settlement Period *t*.

$$AGCDownQualifySelfHA_{jt} = \sum_{z} AGCDownQualifySelfHA_{jzt}$$

where:

$AGCDownQualifySelfDA_{jyt}$ is the The Qualified Day-Ahead Self-Provision of Regulation Down for Scheduling Coordinator *j* in Region *y* for Settlement Period *t*.

$AGCDownQualifySelfHA_{jzt}$ is the Qualified Hour-Ahead Self-Provision of Regulation Down for Scheduling Coordinator *j* in Region *z* for Settlement Period *t*.

The ISO will charge each Scheduling Coordinator a Regulation Down Neutrality Adjustment Charge for each Settlement Period according to Demand.

$$AGCDownNeutraAdjChg_{jt} = MeteredLoad_{jt} \times AGCDownNeutraAdjRate_{t}$$

where:

$AGCDownNeutraAdjChg_{jt}$ is the Regulation Down Neutrality Adjustment Charge to Scheduling Coordinator *j* for Settlement Period *t*.

$MeteredLoad_{jt}$ is the Demand of Scheduling Coordinator j for Settlement Period *t*.

$AGCDownNeutraAdjRate_{t}$ is the Regulation Down Neutrality Adjustment Rate for Settlement Period *t*. The rate is the difference between the total amount of charge and the total amount of payment for the service divided by the total Demand of the ISO control area as follows.

$$AGCDownNeutraAdjRate_{t} = \frac{AGCDownChgTotal_{t} - AGCDownPayTotal_{t}}{MeteredLoadTotal_{t}}$$

where:

$AGCDownChgTotal_{t}$ is the total amount of charges collected by the ISO from Scheduling Coordinators for provision of Regulation Down Service for the Settlement Period *t*.

$$AGCDownChgTotal_{t} = \sum_{j} AGCDownChg_{jt}$$

$AGCDownPayTotal_{t}$ is the total amount of payment from the ISO to Scheduling Coordinators for procuring Regulation Down Service for the Settlement Period *t* in both the Day-Ahead and the Hour-Ahead Markets.

$$AGCDownPayTotal_t = \sum_j \sum_x \left(AGCDownPayTotalDA_{jxt} + AGCDownPayTotalHA_{jxt}\right)$$

C.2.2.3. Spinning Reserve

The ISO will charge the cost of procuring Spinning Reserve in the Day-Ahead and Hour-Ahead Markets, through the application of a charge to each Scheduling Coordinator for each Settlement Period at the ISO Control Area level. This charge will be computed by multiplying the Spinning Reserve user rate for the Settlement Period by the Scheduling Coordinator's Net Spinning Reserve Obligation for the same period.

The Spinning Reserve user rate is calculated by dividing the total cost to the ISO for purchasing the Net Spinning Reserve Requirement, for the Settlement Period, by the Net Spinning Reserve Requirement for the Settlement Period.

The Spinning Reserve user rate for Settlement Period t is calculated as follows:

$$SpinRate_t = \frac{SpinPayNetReqDA_t + SpinPayNetReqHA_t}{SpinNetReqDA_t + SpinNetReqHA_t}$$

where:

$SpinNetReqDA_t$ is the Net Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market. It is the sum of all the Regional Net Spinning Reserve Requirement as follows:

$$SpinNetReqDA_t = \sum_y SpinNetReqDA_{yt}$$

$SpinPayNetReqDA_t$ is the cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period *t* incurred in the Day-Ahead Market. It is calculated as follows:

$$SpinPayNetReqDA_t = \sum_y SpinPayNetReqDA_{yt}$$

$SpinPayNetReqDA_{yt}$ is the cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market in Region *y*. It is calculated as follows:

$$SpinPayNetReqDA_{yt} = SpinNetReqDA_{yt} \times AvgPSpinDA_{yt}$$

where:

$SpinNetReqDA_{yt}$ is the Net Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market for Region *y*.

$AvgPSpinDA_{yt}$ is the average price for Spinning Reserve for the Settlement Period *t* in the Day-Ahead Market for Region *y*.

$$AvgPSpinDA_{yt} = \frac{\sum_{k \in I_y} SpinQDA_{kt} \times PSpinDA_{kt}}{\sum_{k \in I_y} SpinQDA_{kt}}$$

$SpinQDA_{kt}$ is the quantity of procurement for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point *k* which is connected directly to Region *y*.

$PSpinDA_{kt}$ is the Ancillary Service Marginal Price of Spin for the Settlement Period *t* in the Day-Ahead Market in Region *y* or at Scheduling Point k which is connected directly to Region *y*.

I_y is the set of Ancillary Service Regions that consist of Region y itself and the Scheduling Points that are connected directly to Region *y*.

$SpinNetReqHA_t$ is the Net Spinning Reserve Requirement for the Settlement Period *t* in the Hour-Ahead Market. It is the sum of all the Regional Net Spinning Reserve Requirement as follows:

$$SpinNetReqHA_t = \sum_z SpinNetReqHA_{zt}$$

$SpinPayNetReqHA_t$ is the cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market. It is calculated as follows:

$$SpinPayNetReqHA_t = \sum_z SpinPayNetReqHA_{zt}$$

$SpinPayNetReqHA_{zt}$ is the cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market in Region z. It is calculated as follows:

$$SpinPayNet\,\mathrm{Re}\,qDA_{zt} = SpinNet\,\mathrm{Re}\,qHA_{yt} \times AvgPSpinHA_{kt}$$

where:

$SpinNetReqHA_{zt}$ is the Net Spinning Reserve Requirement for the Settlement Period *t* in the Hour-Ahead Market for Region z.

$AvgPSpinHA_{zt}$ is the average price for Spinning Reserve for the Settlement Period *t* in the Hour-Ahead Market for Region z.

$$AvgPSpinHA_{zt} = \frac{\sum_{k \in I_z} \left(SpinQIHA_{kt} \times PSpinHA_{kt} - SpinReceiveHA_{kt} \right)}{\sum_{k \in I_z} \left(SpinQIHA_{kt} - SpinQDHA_{kt} \right)}$$

$SpinQIHA_{kt}$ is the quantity of Incremental Procurement for the Settlement Period t in the Hour-Ahead Market in Region *z* or at Scheduling Point k which is connected directly to Region *z*.

$PSpinHA_{kt}$ is the Ancillary Service Marginal Price of Spin for the Settlement Period t in the Hour-Ahead Market in Region *z* or at Scheduling Point *k* which is connected directly to Region *z*.

$SpinReceiveHA_{kt}$ is the total charges for Hour-Ahead Buyback of Spinning Reserve for the Settlement Period *t* for Region *z* or Scheduling Point k which is connected directly to Region *z*.

I_z is the set of Ancillary Service Regions that consist of Region *z* itself and the Scheduling Points that are connected directly to Region *z*.

The Spinning Reserve capacity charge for Scheduling Coordinator j for Settlement Period *t* is calculated as follows:

$$SpinChg_{jt} = SpinNetOblig_{jt} \times SpinRate_t$$

$SpinNetOblig_{jt}$ is the Net Spinning Reserve Obligation for Scheduling Coordinator *j* for Settlement Period *t*. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Spinning Reserve.

$$SpinNetOblig_{jt} = SpinGrossOblig_{jt} - SpinQualifySelf_{jt}$$

where:

$SpinGrossOblig_{jt}$ is the gross Spinning Reserve Obligation for Scheduling Coordinator *j* for Settlement Period *t*.

$SpinQualifySelf_{jt}$ is the Qualified Self-Provision of Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$SpinQualifySelf_{jt} = SpinQualifySelfDA_{jt} + SpinQualifySelfHA_{jt}$$

$SpinQualifySelfDA_{jt}$ is the Qualified Day-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$SpinQualifySelfDA_{jt} = \sum_{y} SpinQualifySelfDA_{jyt}$$

$SpinQualifySelfHA_{jt}$ is the Qualified Hour-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$SpinQualifySelfHA_{jt} = \sum_{z} SpinQualifySelfHA_{jzt}$$

where:

$SpinQualifySelfDA_{jyt}$ is the Qualified Day-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator *j* in Region *y* for Settlement Period *t*.

$SpinQualifySelfHA_{jzt}$ is the Qualified Hour-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator *j* in Region *z* for Settlement Period *t*.

The ISO will charge each Scheduling Coordinator a Spinning Reserve Neutrality Adjustment Charge for each Settlement Period according to Metered Demand.

$$SpinNeutraAdjChg_{jt} = MeteredDemand_{jt} \times SpinNeutraAdjRate_t$$

where:

$SpinNeutraAdjChg_{jt}$ is the Spinning Reserve Neutrality Adjustment Charge to Scheduling Coordinator j for Settlement Period *t*.

$MeteredDemand_{jt}$ is the metered demand of Scheduling Coordinator *j* for Settlement Period *t*.

$SpinNeutraAdjRate_t$ is the Spinning Reserve Neutrality Adjustment Rate for Settlement Period *t*. The rate is the difference between the total amount of charge and the total amount of payment adjusted by the total congestion charge for the service divided by the total Metered Demand of the control area as follows.

$$SpinNeutraAdjRate_t = \frac{SpinChgTotal_t - SpinPayTotal_t - SpinCCTotal_t}{MeteredDemandTotal_t}$$

where:

$SpinChgTotal_t$ is the total amount of charges collected by the ISO from Scheduling Coordinators for provision of Spinning Reserve Service for the Settlement Period *t*.

$$SpinChgTotal_t = \sum_j SpinChg_{jt}$$

$SpinPayTotal_t$ is the total amount of payment from the ISO to Scheduling Coordinators for procuring Spinning Reserve Service for the Settlement Period *t* in both the Day-Ahead and the Hour-Ahead Markets.

$$SpinPayTotal_t = \sum_j \sum_x \left(SpinPayTotalDA_{jxt} + SpinPayTotalHA_{jxt}\right)$$

$SpinCCTotal_t$ is the total amount of Congestion Charge incurred to the ISO for procuring Spinning Reserve over Congested interties for the Settlement Period t. This amount should be transferred into the FTR Balancing Account to balance the Congestion Charge receivables booked in the Day-Ahead Market and the Hour-Ahead Market when the Spinning Reserves are procured.

$$SpinCCTotal_t = \sum_j \sum_x \sum_i SpinCCDA_{ijxt} + \sum_j \sum_x \sum_i \left(SpinCCHA_{ijxt} - SpinCPHA_{ijxt}\right)$$

C.2.2.4. Non-Spinning Reserve

The ISO will charge the cost of procuring Non-Spinning Reserve in the Day-Ahead and Hour-Ahead Markets, through the application of a charge to each Scheduling Coordinator for each Settlement Period at the ISO Control Area level. This charge will be computed by multiplying the Non-Spinning Reserve user rate for the Settlement Period by the

Scheduling Coordinator's Net Non-Spinning Reserve Obligation for the same period.

The Non-Spinning Reserve user rate is calculated by dividing the total cost to the ISO for purchasing the Net Non-Spinning Reserve Requirement, for the Settlement Period, by the Net Non-Spinning Reserve Requirement for the Settlement Period.

The Non-Spinning Reserve user rate for Settlement Period *t* is calculated as follows:

$$NonSpinRate_t = \frac{NonSpinPayNetReqDA_t + NonSpinPayNetReqHA_t}{NonSpinNetReqDA_t + NonSpinNetReqHA_t}$$

where:

$NonSpinNetReqDA_t$ is the Net Non-Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market. It is the sum of all the Regional Net Non-Spinning Reserve Requirement as follows:

$$NonSpinNetReqDA_t = \sum_y NonSpinNetReqDA_{yt}$$

$NonSpinPayNetReqDA_t$ is the cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period *t* incurred in the Day-Ahead Market. It is calculated as follows:

$$NonSpinPayNetReqDA_t = \sum_y NonSpinPayNetReqDA_{yt}$$

$NonSpinPayNetReqDA_{yt}$ is the cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market in Region *y*. It is calculated as follows:

$$NonSpinPayNet\,\mathrm{Re}\,qDA_{yt} = NonSpinNet\,\mathrm{Re}\,qDA_{yt} \times AvgPNonSpinDA_{yt}$$

where:

$NonSpinNetReqDA_{yt}$ is the Net Non-Spinning Reserve Requirement for the Settlement Period *t* in the Day-Ahead Market for Region *y*.

$AvgPNonSpinDA_{yt}$ is the average price for Non-Spinning Reserve for the Settlement Period *t* in the Day-Ahead Market for Region *y*.

$$AvgPNonSpinDA_{yt} = \frac{\sum_{k \in I_y} NonSpinQDA_{kt} \times PNonSpinDA_{kt}}{\sum_{k \in I_y} NonSpinQDA_{kt}}$$

$NonSpinQDA_{kt}$ is the quantity of procurement for the Settlement Period t in the Day-Ahead Market in Region *y* or at Scheduling Point *k* which is connected directly to Region *y*.

$PNonSpinDA_{kt}$ is the Ancillary Service Marginal Price of Non-Spinning Reserve for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point *k* which is connected directly to Region *y*.

I_y = The set of Ancillary Service Regions that consist of Region y itself and the Scheduling Points that are connected directly to Region *y*.

$NonSpinNetReqHA_t$ is the Net Non-Spinning Reserve Requirement for the Settlement Period *t* in the Hour-Ahead Market. It is the sum of all the Regional Net Non-Spinning Reserve Requirement as follows:

$$NonSpinNetReqHA_t = \sum_z NonSpinNetReqHA_{zt}$$

$NonSpinPayNetReqHA_t$ is the cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market. It is calculated as follows:

$$NonSpinPayNetReqHA_t = \sum_z NonSpinPayNetReqHA_{zt}$$

$NonSpinPayNetReqHA_{zt}$ is the cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period *t* incurred in the Hour-Ahead Market in Region *z*. It is calculated as follows:

$$NonSpinPayNet\,\mathrm{Re}\,qDA_{zt} = NonSpinNet\,\mathrm{Re}\,qHA_{zt} \times AvgPNonSpinHA_{zt}$$

where:

$NonSpinNetReqHA_{zt}$ is the Net Non-Spinning Reserve Requirement for the Settlement Period *t* in the Hour-Ahead Market for Region *z*.

$AvgPNonSpinHA_{zt}$ is the average Pprice for Non-Spinning Reserve for the Settlement Period *t* in the Hour-Ahead Market for Region *z*.

$$AvgPNonSpinHA_{zt} = \frac{\sum_{k \in I_z} \left(NonSpinQIHA_{kt} \times PNonSpinHA_{kt} - NonSpin\,\mathrm{Re}\,ceiveHA_{kt}\right)}{\sum_{k \in I_z} \left(NonSpinQIHA_{kt} - NonSpinQDHA_{kt}\right)}$$

$NonSpinQIHA_{kt}$ is the quantity of incremental procurement for the Settlement Period *t* in the Hour-Ahead Market in Region *z* or at Scheduling Point *k* which is connected directly to Region z.

$PNonSpinHA_{kt}$ is the Ancillary Service Marginal Price of Non-Spinning Reserve for the Settlement Period *t* in the Hour-Ahead Market in Region *z* or at Scheduling Point *k* which is connected directly to Region *z*.

$NonSpinReceiveHA_{kt}$ is the total charges for Hour-Ahead Buyback of Non-Spinning Reserve for the Settlement Period *t* for Region *z* or Scheduling Point *k* which is connected directly to Region z.

I_z is the set of Ancillary Service Regions that consist of Region *z* itself and the Scheduling Points that are connected directly to Region *z*.

The Non-Spinning Reserve capacity charge for Scheduling Coordinator *j* for Settlement Period *t* is calculated as follows:

$$NonSpinChg_{jt} = NonSpinNetOblig_{jt} \times NonSpinRate_t$$

$NonSpinNetOblig_{jt}$ is the Net Non-Spinning Reserve Obligation for Scheduling Coordinator *j* in Ancillary Service Region *x* for Settlement Period *t*. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Non-Spinning Reserve.

$$NonSpinNetOblig_{jt} = NonSpinGrossOblig_{jt} - NonSpinQualifySelf_{jt}$$

where:

$NonSpinGrossOblig_{jt}$ is the gross Non-Spinning Reserve Obligation for Scheduling Coordinator *j* for Settlement Period *t*.

$NonSpinQualifySelf_{jt}$ is the Qualified Self-Provision of Non-Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$NonSpinQualifySelf_{jt} = NonSpinQualifySelfDA_{jt} + NonSpinQualifySelfHA_{jt}$$

$NonSpinQualifySelfDA_{jt}$ is the Qualified Day-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$NonSpinQualifySelfDA_{jxt} = NonSpinQualifySelfDA_{jyt} \times \frac{NonSpinGrossOblig_{jxt}}{NonSpinGrossOblig_{jyt}}$$

$NonSpinQualifySelfHA_{jt}$ is the Qualified Hour-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator *j* for Settlement Period *t*.

$$NonSpinQualifySelfHA_{jt} = \sum_{z} NonSpinQualifySelfHA_{jzt}$$

where:

$NonSpinQualifySelfDA_{jyt}$ = The Qualified Day-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator j in Region y for Settlement Period t.

$NonSpinQualifySelfHA_{jzt}$ = The Qualified Hour-Ahead Self-Provision of Non-Spinning Reserve for Scheduling Coordinator j in Region z for Settlement Period t.

The ISO will charge each Scheduling Coordinator a Non-Spinning Reserve Neutrality Adjustment Charge for each Settlement Period according to Metered Demand.

$$NonSpinNeutraAdjChg_{jt} = MeteredDemand_{jt} * NonSpinNeutraAdjRate_t$$

where

$NonSpinNeutraAdjChg_{jt}$ = Non-Spinning Reserve Neutrality Adjustment Charge to Scheduling Coordinator j for Settlement Period t.

$MeteredDemand_{jt}$ = the metered demand of Scheduling Coordinator j for Settlement Period t.

$NonSpinNeutraAdjRate_t$ = the Non-Spinning Reserve Neutrality Adjustment Rate for Settlement Period t. The rate is the difference between the total amount of charge and the total amount of payment adjusted by the total congestion charge for the service divided by the total Metered Demand of the control area as follows.

$$NonSpinNeutraAdjRate_t = \frac{NonSpinChgTotal_t - NonSpinPayTotal_t - NonSpinCCTotal_t}{MeteredDemandTotal_t}$$

where

$NonSpinChgTotal_t$ = Total amount of charges collected by the ISO from Scheduling Coordinators for provision of Non-Spinning Reserve Service for the Settlement Period t.

$$NonSpinChgTotal_t = \sum_j NonSpinChg_{jt}$$

$NonSpinPayTotal_t$ = Total amount of payment from the ISO to Scheduling Coordinators for procuring Non-Spinning Reserve Service for the Settlement Period t in both the Day-Ahead and the Hour-Ahead Markets.

$$NonSpinPayTotal_t = \sum_j \sum_x \left(NonSpinPayTotalDA_{jxt} + NonSpinPayTotalHA_{jxt}\right)$$

$NonSpinCCTotal_t$ is the total amount of Congestion Charge incurred to the ISO for procuring Non-Spinning Reserve over Congested interties for the Settlement Period *t*. This amount should be transferred into the FTR Balancing Account to balance the Congestion Charge receivables booked in the Day-Ahead Market and the Hour-Ahead Market when the Non-Spinning Reserves are procured.

$$NonSpinCCTotal_t = \sum_j \sum_x \sum_i NonSpinCCDA_{ijxt} + \sum_j \sum_x \sum_i \left(NonSpinCCHA_{ijxt} - NonSpinCPHA_{ijxt}\right)$$

C 2.3. Default User Rate

If, in any Settlement Period, no quantity of Regulation, Spinning Reserve, or Non-Spinning Reserve is purchased in the Day-Ahead or Hour-Ahead Markets due to excess self-provision in all Ancillary Service Regions, then in lieu of the user rate determined in accordance with this

Appendix C the user rate for the affected Ancillary Service for that Settlement Period in the region shall be determined to be zero.

C.3. Meaning of Terms in Formulae

C.3.1. $AGCUpPayDA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing Regulation Up capacity in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.2. $AGCDownPayDA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing Regulation Down capacity in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.3. $AGCUpQDA_{ijxt}$ – MW

The total quantity of Regulation Up capacity provided in the ISO Day-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.4. $AGCDownQDA_{ijxt}$ – MW

The total quantity of Regulation Down capacity provided in the ISO Day-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.5. $PAGCUpDA_{xt}$ - $/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those Units subject to the cap for Regulation Up Capacity in the Day-Ahead Market for Settlement Period t in Ancillary Service Region x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Regulation Up Capacity in Ancillary Service Region x for Settlement Period t.

C.3.6. $PAGCDownDA_{xt}$ - $/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those Units subject to the cap for Regulation Down Capacity in the Day-Ahead Market for Settlement Period t in Ancillary Service Region x. In the case of Capacity not included in the ISO's Final Day-Ahead

Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Regulation Down Capacity in Ancillary Service Region x for Settlement Period t.

C.3.7. $AGCUpPayTotalDA_{jxt}$ - $

The total payment for Regulation Up capacity to Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

$AGCDownPayTotalDA_{jxt}$ - $

The total payment for Regulation Down capacity to Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.8. $AGCUpPayHA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Regulation Up capacity in the Hour-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

$AGCDownPayHA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Regulation Down capacity in the Hour-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.9. $AGCUpReceiveHA_{ijxt}$ - $

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead Regulation Up capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.10. $AGCDownReceiveHA_{ijxt}$ - $

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead Regulation Down capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.11. $AGCUpQIHA_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Regulation Up capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.12. $AGCDownQIHA_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Regulation Down capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.13. $AGCUpQDHA_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Regulation Up capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.14. $AGCDownQDHA_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Regulation Down capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.15. $PAGCUpHA_{xt}$ - $/MW

The Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Regulation Up capacity in the Hour-Ahead Market for Settlement Period t in Ancillary Service Region x. On buyback condition, MCP applies.

C.3.16. $PAGCDownHA_{xt}$ - $/MW

The Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Regulation Down capacity in the Hour-Ahead Market for Settlement Period t in Ancillary Service Region x. On buyback condition, MCP applies.

C.3.17. $AGCUpPayTotalHA_{jxt}$ - $

The total payment for incremental (additional to Day-Ahead) Regulation Up capacity to Scheduling Coordinator j in the Hour-Ahead Market in Ancillary Service Region x for Settlement Period t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Regulation Up capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.18. $AGCDownPayTotalHA_{jxt}$ - $

The total payment for incremental (additional to Day-Ahead) Regulation Down capacity to Scheduling Coordinator j in the Hour-Ahead Market in Ancillary Service Region x for Settlement Period t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Regulation Down capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.19. $SpinPayDA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing Spinning Reserve capacity in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.20. $SpinQDA_{ijxt}$ – MW

The total quantity of Spinning Reserve capacity provided in the Day-Ahead Market by resource i represented by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities..

C.3.21. $PSpinDA_{xt}$ -$/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Day-Ahead Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for Spinning Reserve Capacity in Ancillary Service Region x for Settlement Period t. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Spinning Reserve Capacity in Ancillary Service Region x for Settlement Period t.

C.3.22. $SpinPayTotalDA_{jxt}$ - $

The total payment to Scheduling Coordinator j for Spinning Reserve capacity in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.23. $SpinPayHA_{ijxt}$ - $

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.24. $SpinReceiveHA_{ijxt}$ - $

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.25. $SpinQIHA_{ijxt}$ – MW

The total quantity of incremental (additional to Day-Ahead) Spinning Reserve capacity provided in the Hour-Ahead Market by resource i represented by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.26. $SpinQDHA_{ijxt}$ – MW

The total quantity of decremental (less than Day-Ahead) Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.27. $PSpinHA_{xt}$ -\$/MW

The Hour-Ahead Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Spinning Reserve capacity in Ancillary Service Region x for Settlement Period t. On Buyback condition, MCP applies charge for HA.

C.3.28. $SpinPayTotalHA_{jxt}$ - \$

The total payment to Scheduling Coordinator j for incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market in Ancillary Service Region x for Settlement Period t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.29. $NonSpinPayDA_{ijxt}$ - \$

The payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.30. $NonSpinQDA_{ijxt}$ – MW

The total quantity of Non-Spinning Reserve capacity provided from resource i in the Day-Ahead Market by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.31. $PNonSpinDA_{xt}$ - \$/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Day-Ahead Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for Non-Spinning Reserve Capacity for Settlement Period t in Ancillary Service Region x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 2.5.21, the bid price for the unit for Non-Spinning Reserve Capacity in Ancillary Service Region x for Settlement Period t.

C.3.32. **NonSpinPayTotalDA$_{jxt}$ - $**

The total payment to Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.33. **NonSpinPayHA$_{ijxt}$ - $**

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.34. **NonSpinReceiveHA$_{ijxt}$ - $**

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Ancillary Service Region x for Settlement Period t.

C.3.35. **NonSpinQIHA$_{ijxt}$ – MW**

The total quantity of incremental (additional to Day-Ahead) Non-Spinning Reserve capacity provided from resource i in the Hour-Ahead Market by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.36. **NonSpinQDHA$_{ijxt}$ – MW**

The total quantity of decremental (less than Day-Ahead) Non-Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Ancillary Service Region x for Settlement Period t, not including self-provided quantities.

C.3.37. **PNonSpinHA$_{xt}$ - $/MW**

The Hour-Ahead zonal Ancillary Service Marginal Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Non-Spinning Reserve capacity for Settlement Period t in Ancillary Service Region x. On Buyback condition MCP applies.

C.3.38. **NonSpinPayTotalHA$_{jxt}$ - $**

The total payment to Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market in Ancillary Service Region x for Settlement Period t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Ancillary Service Region x for Settlement Period t.

C.3.39. **PCCDA$_{xt}$ - $/MW**

Price of Congestion Charge in the Day-Ahead Market at Scheduling Point x for Settlement Period t.

C.3.40. $PCCHA_{xt}$ - $/MW

Price of Congestion Charge in the Hour-Ahead Market at Scheduling Point x for Settlement Period t.

C.3.41. AGCUpRatet - $/MW

The Regulation Up user rate for Settlement Period t.

C.3.42. $AGCUpNetReqDA_t$ – MW

Net Regulation Up Requirement for the Settlement Period t in the Day-Ahead Market. It is the sum of all the Regional Net Regulation Up Requirement.

C.3.43. $AGCUpPayNetReqDA_t$ - $

Cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Day-Ahead Market.

C.3.44. $AGCUpPayNetReqDA_{yt}$ - $

Cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Day-Ahead Market in Region y.

C.3.45. $AGCUpNetReqDA_{yt}$ – MW

Net Regulation Up Requirement for the Settlement Period t in the Day-Ahead Market for Region y .

C.3.46. $PAGCUpDA_{yt}$ - $/MW

Ancillary Service Marginal Price for Regulation Up for the Settlement Period t incurred in the Day-Ahead Market for Region y.

C.3.47. $AGCUpNetReqHA_t$ – MW

Net Regulation Up Requirement for the Settlement Period t in the Hour-Ahead Market. It is the sum of all the Regional Net Regulation Up Requirement.

C.3.48. $AGCUpPayNetReqHA_t$ - MW

Cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Hour-Ahead Market.

C.3.49. $AGCUpPayNetReqHA_{zt}$ - $

Cost of Regulation Up procurement to meet Net Regulation Up Requirement for the Settlement Period t incurred in the Hour-Ahead Market in Region z.

C.3.50. **$AGCUpNetReqHA_{yt}$ – MW**

Total incremental Net Requirement of Regulation Up for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.51. **$PAGCUpHA_{yt}$ - $/MW**

Ancillary Service Marginal Price for Regulation Up for the Settlement Period t incurred in the Hour-Ahead Market for Region z.

C.3.52. **$AGCUpReceiveHA_{yt}$ - $**

Total charges for Hour-Ahead Buyback of Regulation Up for the Settlement Period t for Region z.

C.3.53. **$AGCUpNetOblig_{jt}$ – MW**

The Net Regulation Up Obligation for Scheduling Coordinator j for Settlement Period t. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Regulation Up.

C.3.54. **$AGCUpGrossOblig_{jt}$ – MW**

The Gross Regulation Up Obligation for Scheduling Coordinator j for Settlement Period t.

C.3.55. **$AGCUpQualifySelf_{jt}$ – MW**

The Qualified Self-Provision of Regulation Up for Scheduling Coordinator j for Settlement Period t.

C.3.56. **$AGCUpQualifySelfDA_{jt}$ – MW**

The Qualified Day-Ahead Self-Provision of Regulation Up for Scheduling Coordinator j for Settlement Period t.

C.3.57. **$AGCUpQualifySelfHA_{jt}$ – MW**

The Qualified Hour-Ahead Self-Provision of Regulation Up for Scheduling Coordinator j for Settlement Period t.

C.3.58. **$AGCUpQualifySelfDA_{jyt}$ – MW**

The Qualified Day-Ahead Self-Provision of Regulation Up for Scheduling Coordinator j in Region y for Settlement Period t.

C.3.59. **$AGCUpQualifySelfHA_{jzt}$ – MW**

The Qualified Hour-Ahead Self-Provision of Regulation Up for Scheduling Coordinator j in Region z for Settlement Period t.

C.3.60. $AGCUpGrossOblig_{jyt}$ – MW

The Gross Regulation Up Obligation for Scheduling Coordinator j in Region y (defined in Day-Ahead) for Settlement Period t.

C.3.61. $AGCUpGrossOblig_{jzt}$ – MW

The Gross Regulation Up Obligation for Scheduling Coordinator j in Region z (defined in Hour-Ahead) for Settlement Period t.

C.3.62. Regulation Up Neutrality Adjustment Rate – $/MW

The ISO will charge each Scheduling Coordinator a Regulation Up Neutrality Adjustment Charge in proportion to Demand. The rate for this charge is the difference between the total amount that the ISO pays out and the total amount that the ISO collects divided by the total Demand of the ISO Control Area.

C.3.63. $AGCDownRate_t$ - $/MW

Regulation Down user rate for Settlement Period t is calculated.

C.3.64. $AGCUpNetReqDA_t$ – MW

Net Regulation Down Requirement for the Settlement Period t in the Day-Ahead Market. It is the sum of all the Regional Net Regulation Down Requirement.

C.3.65. $AGCDownPayNetReqDA_t$ - $

Cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period t incurred in the Day-Ahead Market.

C.3.66. $AGCDownPayNetReqDA_{yt}$ - $

Cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period t incurred in the Day-Ahead Market in Region y.

C.3.67. $AGCDownNetReqDA_{yt}$ – MW

Net Regulation Down Requirement for the Settlement Period t in the Day-Ahead Market for Region y.

C.3.68. $PAGCDownDA_{yt}$ - $/MW

Ancillary Service Marginal Price for Regulation Down for the Settlement Period t incurred in the Day-Ahead Market for Region y.

C.3.69. $AGCDownNetReqHA_t$ – MW

Net Regulation Down Requirement for the Settlement Period t in the Hour-Ahead Market. It is the sum of all the Regional Net Regulation Down Requirement.

C.3.70. **$AGCDownPayNetReqHA_t$ - $**

Cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period t incurred in the Hour-Ahead Market.

C.3.71. **$AGCDownPayNetReqHA_{zt}$ - $**

Cost of Regulation Down procurement to meet Net Regulation Down Requirement for the Settlement Period t incurred in the Hour-Ahead Market in Region z.

C.3.72. **$AGCDownNetReqHA_{zt}$ – MW**

Total incremental Net Requirement of Regulation Down for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.73. **$PAGCDownHA_{zt}$ - $/MW**

Ancillary Service Marginal Price for Regulation Down for the Settlement Period t incurred in the Hour-Ahead Market for Region z.

C.3.74. **$AGCDownReceiveHA_{zt}$ - $**

Total charges for Hour-Ahead buy-back of Regulation Down for the Settlement Period t for Region z.

C.3.75. **$AGCDownNetOblig_{jt}$ – MW**

The Net Regulation Down Obligation for Scheduling Coordinator j for Settlement Period t. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Regulation Down.

C.3.76. **$AGCDownGrossOblig_{jt}$ – MW**

The Gross Regulation Down Obligation for Scheduling Coordinator j for Settlement Period t.

C.3.77. **$AGCDownQualifySelf_{jt}$ – MW**

The Qualified Self-Provision of Regulation Down for Scheduling Coordinator j for Settlement Period t.

C.3.78. **$AGCDownQualifySelfDA_{jt}$ – MW**

The Qualified Day-Ahead Self-Provision of Regulation Down for Scheduling Coordinator j for Settlement Period t.

C.3.79. **$AGCDownQualifySelfHA_{jt}$ – MW**

The Qualified Hour-Ahead Self-Provision of Regulation Down for Scheduling Coordinator j for Settlement Period t.

C.3.80. **AGCDownQualifySelfDA$_{jyt}$ – MW**

The Qualified Day-Ahead Self-Provision of Regulation Down for Scheduling Coordinator j in Region y for Settlement Period t.

C.3.81. **AGCDownQualifySelfHA$_{jzt}$ – MW**

The Qualified Hour-Ahead Self-Provision of Regulation Down for Scheduling Coordinator j in Region z for Settlement Period t.

C.3.82. **AGCDownGrossOblig$_{jyt}$ – MW**

The Gross Regulation Down Obligation for Scheduling Coordinator j in Region y (defined in Day-Ahead) for Settlement Period t.

C.3.83. **AGCDownGrossOblig$_{jzt}$ – MW**

The Gross Regulation Down Obligation for Scheduling Coordinator j in Region z (defined in Hour-Ahead) for Settlement Period t.

C.3.84. **AGCDownNeutraAdjRate - $/MW**

The ISO will charge each Scheduling Coordinator a Regulation Down Neutrality Adjustment Charge in proportion to Demand. The rate for this charge is the difference between the total amount that the ISO pays out and the total amount that the ISO collects divided by the total Demand of the ISO Control Area.

C.3.85. **SpinRate$_t$ - $/MW**

The Spinning Reserve user rate for Settlement Period t.

C.3.86. **SpinNetReqDA$_t$ – MW**

Net Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market. It is the sum of all the Regional Net Spinning Reserve Requirement.

C.3.87. **SpinPayNetReqDA$_t$ - $**

Cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period t incurred in the Day-Ahead Market.

C.3.88. **SpinPayNetReqDA$_{yt}$ - $**

Cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market in Region y.

C.3.89. **SpinNetReqDA$_{yt}$ – MW**

Net Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market for Region y.

C.3.90. **$AvgPSpinDA_{yt}$ - $/MW**

Average Price for Spinning Reserve for the Settlement Period t in the Day-Ahead Market for Region y.

C.3.91. **$SpinQDA_{kt}$ – MW**

Quantity of procurement for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point k which is connected directly to Region y.

C.3.92. **$PSpinDA_{kt}$ - $/MW**

Ancillary Service Marginal Price of Spin for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point k which is connected directly to Region y.

C.3.93. **$PCCDA_{kt}$ – $/MW**

Price of Congestion Charge for the Settlement Period t in the Day-Ahead Market at Scheduling Point k which is connected directly to Region y.

C.3.94. **$SpinNetReqHA_t$ – MW**

Net Spinning Reserve Requirement for the Settlement Period t in the Hour-Ahead Market. It is the sum of all the Regional Net Spinning Reserve Requirement.

C.3.95. **$SpinPayNetReqHA_t$ - $**

Cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period t incurred in the Hour-Ahead Market.

C.3.96. **$SpinPayNetReqHA_{zt}$ - $**

Cost of Spinning Reserve procurement to meet Net Spinning Reserve Requirement for the Settlement Period t incurred in the Hour-Ahead Market in Region z.

C.3.97. **$SpinNetReqHA_{zt}$ – MW**

Net Spinning Reserve Requirement for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.98. **$AvgPSpinHA_{zt}$ - $/MW**

Average Price for Spinning Reserve for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.99. **$SpinQIHA_{kt}$ – MW**

Quantity of Incremental Procurement for the Settlement Period t in the Hour-Ahead Market in Region z or at Scheduling Point k which is connected directly to Region z.

C.3.100. **$PSpinHA_{kt}$ - $/MW**

Ancillary Service Marginal Price of Spinning Reserve for the Settlement Period t in the Hour-Ahead Market in Region z or at Scheduling Point k which is connected directly to Region z.

C.3.101. **$PCCHA_{kt}$ – $/MW**

Price of Congestion Charge for the Settlement Period t in the Hour-Ahead Market at Scheduling Point k which is connected directly to Region z.

C.3.102. **$SpinReceiveHA_{kt}$ - $**

Total charges for Hour-Ahead buyback of Spinning Reserve for the Settlement Period t for Region z or Scheduling Point k which is connected directly to Region z.

C.3.103. **$SpinNetOblig_{jt}$ – MW**

The Net Spinning Reserve Obligation for Scheduling Coordinator j for Settlement Period t. The Charge is negative when the Scheduling Coordinator has Excess Qualified Self-Provision of Spinning Reserve.

C.3.104. **$SpinGrossOblig_{jt}$ – MW**

The Gross Spinning Reserve Obligation for Scheduling Coordinator j for Settlement Period t.

C.3.105. **$SpinQualifySelf_{jt}$ – MW**

The Qualified Self-Provision of Spinning Reserve for Scheduling Coordinator j for Settlement Period t.

C.3.106. **$SpinQualifySelfDA_{jt}$ – MW**

The Qualified Day-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator j for Settlement Period t.

C.3.107. **$SpinQualifySelfHA_{jt}$ – MW**

The Qualified Hour-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator j for Settlement Period t.

C.3.108. **$SpinQualifySelfDA_{jyt}$ – MW**

The Qualified Day-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator j in Region y for Settlement Period t.

C.3.109. $SpinQualifySelfHA_{jzt}$ – MW

The Qualified Hour-Ahead Self-Provision of Spinning Reserve for Scheduling Coordinator j in Region z for Settlement Period t.

C.3.110. $SpinGrossOblig_{jyt}$ – MW

The Gross Spinning Reserve Obligation for Scheduling Coordinator j in Region y (defined in Day-Ahead) for Settlement Period t.

C.3.111. $SpinGrossOblig_{jzt}$ – MW

The Gross Spinning Reserve Obligation for Scheduling Coordinator j in Region z (defined in Hour-Ahead) for Settlement Period t.

C.3.112. SpinNeutraAdjRate - $/MW

The ISO will charge each Scheduling Coordinator a Spinning Reserve Neutrality Adjustment Charge according to Metered Demand. The rate for this charge is the difference between the total amount that the ISO pays out and the total amount that the ISO collects divided by the total Metered Demand of the control area.

C.3.113. NonSpinRate – $/MW

The Non-Spinning Reserve user rate for Settlement Period t.

C.3.114. $NonSpinNetReqDA_t$ – MW

Net Non-Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market. It is the sum of all the Regional Net Non-Spinning Reserve Requirement.

C.3.115. $NonSpinPayNetReqDA_t$ - $

Cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period t incurred in the Day-Ahead Market.

C.3.116. $NonSpinPayNetReqDA_{yt}$ - $

Cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market in Region y.

C.3.117. $NonSpinNetReqDA_{yt}$ – MW

Net Non-Spinning Reserve Requirement for the Settlement Period t in the Day-Ahead Market for Region y.

C.3.118. $AvgPNonSpinDA_{yt}$ - $/MW

Average Price for Non-Spinning Reserve for the Settlement Period t in the Day-Ahead Market for Region y.

C.3.119. **$NonSpinQDA_{kt}$ – MW**

Quantity of procurement for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point k which is connected directly to Region y.

C.3.120. **$PNonSpinDA_{kt}$ - $/MW**

Ancillary Service Marginal Price of Non-Spinning Reserve for the Settlement Period t in the Day-Ahead Market in Region y or at Scheduling Point k which is connected directly to Region y.

C.3.121. **$NonSpinNetReqHA_{t}$ – MW**

Net Non-Spinning Reserve Requirement for the Settlement Period t in the Hour-Ahead Market. It is the sum of all the Regional Net Non-Spinning Reserve Requirement.

C.3.122. **$NonSpinPayNetReqHA_{t}$ - $**

Cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period t incurred in the Hour-Ahead Market.

C.3.123. **$NonSpinPayNetReqHA_{zt}$ - $**

Cost of Non-Spinning Reserve procurement to meet Net Non-Spinning Reserve Requirement for the Settlement Period t incurred in the Hour-Ahead Market in Region z.

C.3.124. **$NonSpinNetReqHA_{zt}$ – MW**

Net Non-Spinning Reserve Requirement for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.125. **$AvgPNonSpinHA_{zt}$ - $/MW**

Average Price for Non-Spinning Reserve for the Settlement Period t in the Hour-Ahead Market for Region z.

C.3.126. **$NonSpinQIHA_{kt}$ – MW**

Quantity of Incremental Procurement for the Settlement Period t in the Hour-Ahead Market in Region z or at Scheduling Point k which is connected directly to Region z.

C.3.127. **$PNonSpinHA_{kt}$ – $/MW**

Ancillary Service Marginal Price of Non-Spinning Reserve for the Settlement Period t in the Hour-Ahead Market in Region z or at Scheduling Point k which is connected directly to Region z.

C.3.128. **$NonSpinReceiveHA_{kt}$ - $**