12 CREDITWORTHINESS.

12.1 Credit Requirements.

The creditworthiness requirements in this section apply to the ISO's acceptance of Schedules, to all transactions in an ISO Market, to the payment of charges pursuant to the ISO Tariff (including the Grid Management Charge), and to establish credit limits for participation in any ISO auction of FTRs or CRRs and to CRR Holders for the holding of CRRs. Each Market Participant (including each Scheduling Coordinator, UDC, MSS, CRR Holder, or Candidate CRR Holder) or FTR Bidder shall secure its financial transactions with the ISO (including its participation in any auction of FTRs or CRRs and for the holding of CRRs) by maintaining an Unsecured Credit Limit and/or by posting Financial Security, the level of which constitutes the Market Participant's or FTR Bidder's Financial Security Amount. For each Market Participant or FTR Bidder, the sum of its Unsecured Credit Limit and its Financial Security Amount shall represent its Aggregate Credit Limit. Each Market Participant or FTR Bidder shall have the responsibility to maintain an Aggregate Credit Limit that is at least equal to its Estimated Aggregate Liability.

12.1.1 Unsecured Credit Limit.

Each Market Participant or FTR Bidder requesting an Unsecured Credit Limit shall submit an application to the ISO in the form specified on the ISO Home Page. The ISO shall determine the Unsecured Credit Limit for each Market Participant or FTR Bidder in accordance with the procedures set forth in the ISO Credit Policy & Procedures Guide posted on the ISO Home Page. The maximum Unsecured Credit Limit for any Market Participant or FTR Bidder shall be $250 million. In accordance with the procedures described in the ISO Credit Policy & Procedures Guide, each Market Participant or FTR Bidder requesting or maintaining an Unsecured Credit Limit is required to submit to the ISO or its agent financial statements and other information related to its overall financial health as directed by the ISO. Each Market Participant or FTR Bidder is responsible for the timely submission of its latest financial statements as well as other information that may be reasonably necessary for the ISO to conduct its evaluation. The ISO shall determine the Unsecured Credit Limit for each Market Participant or FTR Bidder as described in Sections 12.1.1A, 12.1.1A.1, 12.1.1A.2.

As a result of the ISO's credit evaluation, a Market Participant or FTR Bidder may be given an Unsecured Credit Limit by the ISO or denied an Unsecured Credit Limit with the ISO. Following the initial application and the establishment of an Unsecured Credit limit, the ISO will review each Market Participant's or FTR Bidder's Unsecured Credit Limit on a quarterly basis, unless that entity does not prepare quarterly statements, in which case the review will occur on an annual basis, and no entity shall be required to submit a new application. In addition, the ISO may review the Unsecured Credit Limit for any Market Participant or FTR Bidder whenever the ISO becomes aware of information that could indicate a Material Change in Financial Condition. In the event the ISO determines that the Unsecured Credit Limit of a Market Participant or FTR Bidder must be reduced as a result of a subsequent review, the ISO shall notify the Market Participant or FTR Bidder of the reduction, and shall, upon request, also provide the Market Participant or FTR Bidder with a written explanation of why the reduction was made.

12.1.1A Unsecured Credit Limit Calculation.

An Unsecured Credit Limit (UCL) for each Market Participant and FTR Bidder that is a Public/Private Corporation, a Governmental Entity, or a Local Publicly Owned Electric Utility and that requests an Unsecured Credit Limit is calculated as follows:

1. **Rated Public/Private Corporations –** The Unsecured Credit Limit is the lesser of $250 million or an amount equal to the Market Participant's or FTR Bidder's Tangible Net Worth (TNW) multiplied by a calculated percentage of TNW. The TNW percentage is comprised of 50 percent (50%) of the Market Participant's or FTR Bidder's Credit Rating Default Probability and 50 percent (50%) of the MKMV Default Probability.

2. **Unrated Public/Private Corporations** – The Unsecured Credit Limit is the lesser of $250 million or an amount equal to the Market Participant's or FTR Bidder's TNW multiplied by a calculated percentage of TNW. The TNW percentage is comprised of 100 percent of the MKMV Default Probability.

3. **Rated Governmental Entities** – The Unsecured Credit Limit is the lesser of $250 million or an amount equal to the Market Participant's or FTR Bidder's Net Assets (NA)

multiplied by a calculated percentage of NA. The NA percentage is comprised of 100 percent of the Market Participant's or FTR Bidder's Credit Rating Default Probability.

4. **(a) Unrated Governmental Entities Other Than Those that Receive Appropriations from the Federal Government or a State Government** – The Unsecured Credit Limit is the lesser of $250 million or an amount equal to a specified percentage of the Market Participant's or FTR Bidder's Net Assets if the Market Participant or FTR Bidder has a minimum of $25 million in Net Assets and its Times Interest Earned, Debt Service Coverage and Equity to Assets ratios (as those ratios are defined in Section A-2.3 of the ISO Credit Policy & Procedures Guide) meet or exceed minimums specified in the ISO Credit Policy & Procedures Guide.

(b) Unrated Governmental Entities that Receive Appropriations from the Federal Government or a State Government – The Unsecured Credit Limit is the lesser of $250 million dollars or the amount appropriated by the federal or relevant state government for the purpose of procuring energy and energy-related products and services for the applicable fiscal year. The Unrated Governmental Entity seeking to establish an Unsecured Credit Limit pursuant to this section shall provide documentation establishing its annual appropriations.

5. **Local Publicly Owned Electric Utilities** – A Local Publicly Owned Electric Utility with a governing body having ratemaking authority that has submitted an application for an Unsecured Credit Limit shall be entitled to an Unsecured Credit Limit of $1 million dollars without regard to its Net Assets. Such Local Publicly Owned Electric Utility shall be entitled to request an Unsecured Credit Limit based on Net Assets as provided in Section 12.1.1.A(3) or 12.1.1A(4) in order to establish an Unsecured Credit Limit as the greater of $1 million dollars or the amount determined as provided in this Section 12.1.1A(5). A public entity that is not a Local Publicly Owned Electric Utility is not entitled to an Unsecured Credit Limit of $1 million dollars under this Section 12.1.1A(5) but may seek to establish an Unsecured Credit Limit as provided in any other provision of the ISO Tariff that may apply.

Public entities, including Local Publicly Owned Electric Utilities, that operate through a Joint Powers Agreement, or a similar agreement acceptable to the ISO with the same legal force and effect, shall be entitled to aggregate or assign their Unsecured Credit Limits subject to the following limitations and requirements. A public entity that is a party to a Joint Powers Agreement or similar agreement and that is also participating independently in the ISO's markets with an established Unsecured Credit Limit shall not be entitled to assign or aggregate any portion of its Unsecured Credit Limit that the public entity is using to support financial liabilities associated with its individual participation in the ISO's markets. A Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate a portion of its Unsecured Credit Limit that is equal to or less than $1 million dollars with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign a portion of its Unsecured Credit Limit that is equal to or less than $1 million dollars to the Joint Powers Authority shall be entitled to do so. A Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate its Unsecured Credit Limit with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign a portion of its Unsecured Credit Limit to the Joint Powers Authority that exceeds $1 million dollars, and any public entity that is not a Local Publicly Owned Electric Utility that operates through a Joint Powers Agreement or similar agreement that desires to aggregate its Unsecured Credit Limit with one or more other Local Publicly Owned Electric Utilities that operate through that Joint Powers Agreement or similar agreement or to assign any portion of its Unsecured Credit Limit to the Joint Powers Authority, shall provide documentation that is acceptable to the

ISO and that demonstrates the Local Publicly Owned Electric Utility or public entity will assume responsibility for the financial liabilities of the Joint Powers Agency associated with the assigned or aggregated portion of the Unsecured Credit Limit. Such documentation may include a guaranty or similar instrument acceptable to the ISO.

Unsecured Credit Limits established pursuant to this Section 12.1.1A shall be subject to the ISO's consideration of the same qualitative factors that apply to all Market Participants and FTR Bidders as set forth in Section 12.1.1.1 and, accordingly, the ISO may adjust their Unsecured Credit Limits pursuant to Section 12.1.1. The $250 million hard cap on Unsecured Credit Limits specified in Section 12.1.1 has been set with respect to the length of the current ISO Payments Calendar, *i.e.*, a maximum of 95 Trading Days of charges outstanding. Upon implementation of payment acceleration (scheduled for 2008), the ISO expects to recommend a reduction in the $250 million hard cap. Any changes to the $250 million cap will require FERC approval of an amendment to the applicable provisions of the ISO Tariff.

12.1.1A.1 Maximum Percentage of Tangible Net Worth and Net Assets.

For Rated and Unrated Public/Private Corporations or Rated Governmental Entities, the maximum percentage of TNW or NA is 7.5 percent (7.5%) if the Market Participant's or FTR Bidder's Combined Default Probability is less than or equal to 0.06 percent (0.06%).

The Maximum Allowable Percentage of 7.5% is for the highest quality firms; that is, those Market Participants and FTR Bidders with a CDP of 0.06 percent or less. The Tangible Net Worth Percentage (TNWP) or Net Assets Percentage (NAP) that a Market Participant or FTR Bidder qualifies for will be reduced as its credit risk increases.

For Unrated Governmental Entities, the ISO may provide an Unsecured Credit Limit of up to 5 percent (5%) of NA.

With respect to either of these potential maximum percentages, a lesser amount of unsecured credit may be granted if the ISO becomes aware of information related to a Material Change in Financial Condition or other significant information that presents a significant risk to the creditworthiness of the entity.

12.1.1A.2 Unsecured Credit Limit Calculation Steps.

An eight-step process is used to determine Unsecured Credit Limits for Market Participants and FTR Bidders that are Rated Public/Private Corporations, Unrated Public/Private Corporations, and Rated Governmental Entities.

Step 1 – If the Market Participant or FTR Bidder has a credit rating(s) from one or more of the "Nationally Recognized Statistical Rating Organizations" (NRSRO), verify the rating(s) with the appropriate NRSRO.

Step 2 - Calculate the Market Participant's or FTR Bidder's Average Rating Default Probability (ARDP).

- **a.** ARDP is the sum of Credit Rating Default Probabilities divided by the total number of Credit Rating Default Probabilities used.
- **b.** The median default probability calculated by Moody's KMV (*i.e.*, MKMV) for Standard & Poor's and Moody's long-term credit rating classes is provided on the ISO Website at http://www.caiso.com/1bd8/1bd8b09916e50.html. Default probabilities are available from each NRSRO.
- **c.** Issuer ratings without the benefit of credit enhancement would be used in this assessment. Such ratings are also known as "counterparty" or "underlying" ratings.

Step 3 – Using MKMV's CreditEdge or RiskCalc software, obtain the Market Participant's or FTR Bidder's MKMV Default Probability (MKDP).

- **a.** Since MKMV calculates default probabilities directly, the MKMV Default Probability will be used without any mapping.

Step 4 – Calculate a Combined Default Probability (CDP) based on one of the following methodologies:

- **a.** CDP for Rated Public/Private Corporations = (ARDP * 50%) + (MKDP * 50%)
- **b.** CDP for Unrated Public/Private Corporations = MKDP * 100%
- **c.** CDP for Rated Governmentally Owned Utilities = ARDP * 100%

Step 5 – Calculate the Market Participant's or FTR Bidder's Tangible Net Worth Percentage (TNWP) or Net Assets Percentage (NAP).

a. TNWP = MAP * BDP / CDP for Rated/Unrated Public/Private Corporations

b. NAP = MAP * BDP / CDP for Rated Governmental Entities

Where:

MAP = Maximum Allowable Percentage;

BDP = Base Default Probability;

CDP = see Step 4 above; and

If the SC's CDP > 0.5%, the TNWP or NAP equals 0%

Step 6 – Calculate the Market Participant's or FTR Bidder's Tangible Net Worth or Net Assets.

a. TNW for Rated/Unrated Public/Private Corporations = Assets minus Intangibles (e.g., Good Will) minus Liabilities

b. NA for Rated Governmental Entities = Total Assets minus Total Liabilities

Step 7 – Calculate the Market Participant's or FTR Bidder's Unsecured Credit Limit.

a. UCL = TNW * TNWP for Rated/Unrated Public/Private Corporations

b. UCL = NA * NAP for Rated Governmental Entities

Step 8 – Adjust Unsecured Credit Limit downward, if warranted based on the ISO's review of factors in Section 12.1.1.1.

a. Final UCL = UCL from Step 7 * (0 - 100%)

12.1.1.1 Qualitative and Quantitative Credit Strength Indicators.

n determining a Market Participant's or FTR Bidder's Unsecured Credit Limit, the ISO may rely on information gathered from financial reporting agencies, the general/financial/energy press, and provided by the Market Participant or FTR Bidder to assess its overall financial health and its ability to meet its financial obligations. Information considered by the ISO in this process may include the following qualitative factors:

a) Applicant's history;

b) Nature of organization and operating environment;

c) Management;

d) Contractual obligations;

e) Governance policies;

f) Financial and accounting policies;

g) Risk management and credit policies;

h) Market risk including price exposures, credit exposures and operational exposures;

i) Event risk; and

j) The state or local regulatory environment.

Material negative information in these areas may result in a reduction of up to 100% in the Unsecured Credit Limit that would otherwise be granted based on the eight-step process described in Section 12.1.1A. A Market Participant or FTR Bidder, upon request, will be provided a written analysis as to how the provisions in Section 12.1.1A and this section were applied in setting its Unsecured Credit Limit.

12.1.1.2 Financial Statements.

Market Participants and FTR Bidders requesting unsecured credit are required to provide financial statements so that a credit review can be completed. Based on availability, the Market Participant or FTR Bidder must submit a financial statement for the most recent financial quarter, as well as audited financial statements for the most recent three fiscal years, or the period of existence of the Market Participant or FTR Bidder, if shorter, to the ISO or the ISO's designee. If audited financial statements are not available, financial statements, as described below, should be submitted, signed and attested to by an officer of the Market Participant or FTR Bidder as a fair representation of the financial condition of the Market Participant or FTR Bidder in accordance with generally accepted accounting principles. The information should include, but is not limited to, the following:

a. If publicly traded:

i. Annual and quarterly reports on Form 10-K and Form 10-Q, respectively

ii. Form 8-K reports, if any

b. If privately held or governmentally owned:

i. Management's Discussion & Analysis (if available)

ii. Report of Independent Accountants (if available)

iii. Financial Statements, including:

- Balance Sheet
- Income Statement
- Statement of Cash Flows
- Statement of Stockholder's Equity

iv. Notes to Financial Statements

If the above information is available electronically on the Internet, the Market Participant or FTR Bidder may indicate in written or electronic communication where such statements are located for retrieval by the ISO or the ISO's designee.

12.1.1.3 Determination of Unsecured Credit Limits for Affiliates.

If any Market Participant or FTR Bidder requesting or maintaining an Unsecured Credit Limit is affiliated with one or more other entities subject to the credit requirements of this Section 12, the ISO may consider the overall creditworthiness and financial condition of such Affiliates when determining the applicable Unsecured Credit Limit. The ISO may determine that the maximum Unsecured Credit Limit specified in Section 12.1.1 applies to the combined activity of such Affiliates. In the event the ISO determines that the maximum Unsecured Credit Limit applies to the combined activity of the Affiliates and the Market Participant, the ISO shall inform the Market Participant in writing.

12.1.1.4 Notification of Material Change in Financial Condition.

Each Market Participant or FTR Bidder shall notify the ISO in writing of a Material Change in Financial Condition, within five (5) Business Days of when the Material Change in Financial Condition is known or reasonably should be known by the Market Participant or FTR Bidder. The provision to the ISO of a copy of a Form 10-K, 10-Q, or Form 8-K filed with the U.S. Securities and Exchange Commission shall satisfy the requirement of notifying the ISO of such Material Change in Financial Condition. Alternatively, the Market Participant may direct the ISO to the location of the information on their company website or the website of the U.S. Securities & Exchange Commission.

12.1.2 Financial Security and Financial Security Amount.

A Market Participant or FTR Bidder that does not have an Unsecured Credit Limit, or that has an Unsecured Credit Limit that is less than its Estimated Aggregate Liability, shall post Financial Security that is acceptable to the ISO and that is sufficient to ensure that its Aggregate Credit Limit (*i.e.*, the sum of its Unsecured Credit Limit and Financial Security Amount) is equal to or greater than its Estimated Aggregate Liability. The Financial Security posted by a Market Participant or FTR Bidder may be any combination of the following types of Financial Security provided in favor of the ISO and notified to the ISO under Section 12.3:

(a) an irrevocable and unconditional letter of credit issued by a bank or financial institution that is reasonably acceptable to the ISO;

(b) an irrevocable and unconditional surety bond issued by an insurance company that is reasonably acceptable to the ISO;

(c) an unconditional and irrevocable guaranty issued by a company that is reasonably acceptable to the ISO;

(d) a cash deposit standing to the credit of the ISO in an interest-bearing escrow account maintained at a bank or financial institution that is reasonably acceptable to the ISO;

(e) a certificate of deposit in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO;

(f) a payment bond certificate in the name of the ISO issued by a bank or financial institution that is reasonably acceptable to the ISO; or

(g) a prepayment to the ISO.

Financial Security instruments as listed above shall be in such form as the ISO may reasonably require from time to time by notice to Market Participants or FTR Bidders, or in such other form as has been evaluated and approved as reasonably acceptable by the ISO. The ISO shall publish and maintain standardized forms related to the types of Financial Security listed above on the ISO Home Page. The ISO shall require the use of standardized forms of Financial Security to the greatest extent possible.

12.1.2.1 Additional Procedures Regarding Certain Types of Financial Security.

(a) Unconditional and irrevocable guaranties: In those cases where a Market Participant or FTR Bidder is a subsidiary or affiliate of another entity and would like to utilize the consolidated financial statements and other relevant information of that entity for obtaining credit, a signed corporate guaranty is required. A guarantor would be considered reasonably acceptable and a corresponding Financial Security Amount would be set based on the guarantor's credit evaluation according to the same procedures that apply to the credit evaluation of a Market Participant or FTR Bidder.

(b) Cash deposits standing to the credit of the ISO in interest-bearing escrow accounts: Interest on a cash deposit standing to the credit of the ISO in an interest-bearing escrow account will accrue to the Market Participant's or FTR Bidder's benefit and will be added to the Market Participant's or FTR Bidder's prepayment account on a monthly basis. Should a Market Participant or FTR Bidder become delinquent in payments, the Market Participant's or FTR Bidder's outstanding account balance will be satisfied using deposited funds. The Market Participant or FTR Bidder must take care to replenish used funds to ensure that its Aggregate Credit Limit continues to exceed its Estimated Aggregate Liability.

(c) Prepayments to the ISO: Prepayments to the ISO will be held in an interest-bearing account or another investment acceptable to the Market Participant and the ISO, and interest on the investment will accrue at the rate as provided for in the investment. Interest will accrue to the Market Participant's benefit and will be added to the Market Participant's prepayment account on a monthly basis. Due to the additional administrative effort involved in tracking and posting interest on such prepayments, the use of this option is not encouraged.

12.1.2.2 Process for Evaluating Requests to Use Non-Standardized Forms of Financial Security.

A Market Participant or FTR Bidder that seeks permission to use a form for Financial Security other than one or more of the standardized forms posted on the ISO Home Page shall seek such permission in a written request to the ISO that explains the basis for the use of such non-standardized form. The ISO shall have ten (10) Business Days from receipt of such request to evaluate it and determine whether it will be approved as reasonably acceptable. If the ISO does not respond to such request within the ten (10) Business Day period, the request shall be deemed to have been denied. Until and unless the ISO approves the use of a non-standardized form for Financial Security, the Market Participant or FTR Bidder that submitted such request shall be required to use one of the standardized forms for Financial Security described in this Section 12.1.2.

12.1.2.3 Expiration of Financial Security.

Each Market Participant or FTR Bidder shall ensure that the financial instruments it uses for the purpose of providing Financial Security will not expire and thereby cause the Market Participant's or FTR Bidder's Aggregate Credit Limit to fall below the Market Participant's or FTR Bidder's Estimated Aggregate Liability. The ISO will treat a financial instrument that does not have an automatic renewal provision and that is not renewed or replaced within seven (7) days of its date of expiration as being out of compliance with the standards for Financial Security contained in this Section 12 and will deem the value of such financial instrument to be zero, and will draw upon such Financial Security prior to its stated expiration if deemed necessary by the ISO.

12.1.2.4 Risk of Loss of Financial Security Amounts Held and Invested by the ISO.

In accordance with the ISO's investment policy, the ISO will invest each Financial Security Amount of a Market Participant or FTR Bidder only in bank accounts, high-quality money market accounts, and/or U.S. Treasury/Agency securities unless a specific written request is received from the Market Participant or FTR Bidder for a different type of investment and the ISO provides its written consent to such alternative investment. A Market Participant or FTR Bidder that provides a Financial Security Amount that is held and invested by the ISO on behalf of the Market Participant or FTR Bidder will bear all risks that such Financial Security Amount will incur a loss of principal and/or interest as a result of the ISO's investment of such Financial Security Amount.

12.1.3 Self-Supply of UDC Demand.

Notwithstanding anything to the contrary in the ISO Tariff, a Scheduling Coordinator or UDC that is an Original Participating Transmission Owner or is a Scheduling Coordinator for an Original Participating Transmission Owner shall not be precluded by Section 12.3 from scheduling transactions that serve a UDC's Demand from –

(1) a resource that the UDC owns; and

(2) a resource that the UDC has under contract to serve its Demand.

12.1.4 Allocation of Aggregate Credit Limit for FTR Auction Participation.

An FTR Bidder may elect to allocate a portion of its Aggregate Credit Limit toward satisfying the credit requirements for participating in auctions of FTRs, as set forth in Section 36.2.6.

12.1.5 Estimated Aggregate Liability.

The ISO will periodically calculate the Estimated Aggregate Liability of each Market Participant and FTR Bidder, based on all charges and settlement amounts for which such Market Participant or FTR Bidder is liable or reasonably anticipated by the ISO to be liable for pursuant to the ISO Tariff. The Estimated Aggregate Liability for each Market Participant or FTR Bidder shall be determined and applied by the ISO consistent with the procedures set forth in the ISO Credit Policy & Procedures Guide posted on the ISO Home Page. The ISO shall upon request provide each Market Participant or FTR Bidder with information concerning the basis for the ISO's determination of its Estimated Aggregate Liability, and the ISO's determination may be disputed in accordance with the procedures set forth in the ISO Credit Policy & Procedures Guide. The ISO shall compare each Market Participant's or FTR Bidder's Estimated Aggregate Liability against its Aggregate Credit Limit on a periodic basis.

12.1.5A Calculation of Estimated Aggregate Liability.

12.1.5A.1 Calculation Methodology Based on the Level Posting Period.

Except as described in Section 12.1.5A.2, the ISO shall use the method described in this Section 12.1.5A.1 to calculate each Market Participant's Estimated Aggregate Liability. The Estimated Aggregate Liability is based on a "Level Posting Period" equal to 102 Trading Days, which represents the maximum number of Trading Days outstanding at a given time based on the ISO's Payments Calendar (95 Trading Days) plus seven Trading Days based on the allowable period for Market Participants to respond to ISO requests for additional collateral (five Business Days). The charges the ISO shall use to calculate Estimated Aggregate Liability shall be charges described or referenced in the ISO Tariff. The ISO shall calculate the Estimated Aggregate Liability for each Market Participant for a given Level Posting Period by aggregating the following obligations:

- Outstanding obligations – Any past-due open balances of amounts payable by and amounts receivable from the Market Participant, including unpaid FERC Annual Charge balances and excluding balances covered by bankruptcies.

- Invoice obligations – Obligations from either a preliminary or a final invoice that has been issue but not yet paid.
- Actual Settlement obligations – The Market Participant's preliminary and final Settlement obligations up to the date of the latest Preliminary Settlement Statement.
- Estimated obligations – Estimated charges for the Market Participant for the balance of the Level Posting Period. The ISO shall calculate estimated obligations for the Market Participant by multiplying (i) a daily average of published, actual Settlement charges for the Market Participant by (ii) the number of days remaining in the Level Posting Period for which actual Settlement data is unavailable. In calculating (i), above, the ISO shall separate the Market Participant's Settlement activity into daily market activity, monthly market activity, and Grid Management Charge activity, and shall determine the daily average of charges for each such type of activity separately based on the different frequencies with which charges for these types of activities are assessed. The daily average charges used in (i), above, shall normally be based on two months of available historical Settlement data for the Market Participant. The ISO may review the trend of Market Participant historical charges and determine that an alternative of one month or twelve months of historical charges would result in a more accurate estimate, and may use such data to calculate the daily average charges.

For a Market Participant that maintains multiple BAID numbers, the Estimated Aggregate Liability of the Market Participant as a legal entity shall be calculated by summing the Estimated Aggregate Liabilities for all such BAID numbers and comparing the sum of the Estimated Aggregate Liabilities to the Aggregate Credit Limit of the Market Participant. Market Participants may recommend changes to the liability estimates produced by the ISO's Estimated Aggregate Liability calculation through the dispute procedures described in Section 12.4.2.

12.1.5A.2 Calculation Methodology Applicable to New Market Participants.

Each new Market Participant (and each Market Participant that has previously been inactive) is required to post an initial Financial Security Amount to cover a minimum of 14 Trading Days of estimated obligations as well as additional Financial Security as obligations are incurred. This initial posting requirement is based on anticipated scheduling/trading practices and overall volumes, and shall be considered to be equal to the Market Participant's Estimated Aggregate Liability. Until the amount of time elapsed from such Market Participant's initial participation in the ISO Market equals the maximum length of the ISO payment cycle (*i.e.*, 95 Trading Days), the ISO shall monitor the Market Participant's ongoing security requirement by comparing its actual obligations against its estimated obligations to determine if the Market Participant must provide any additional Financial Security Amount in order to ensure that its Estimated Aggregate Liability does not exceed its Aggregate Credit Limit. Once the amount of time elapsed from the Market Participant's initial participation in the ISO Market equals 95 Trading Days, the ISO shall begin calculating the Market Participant's Estimated Aggregate Liability pursuant to Section 12.1.5A.1.

12.1.5A.3 Special Circumstances.

12.1.5A.3.1 Daily Adjustments and Disputes.

Charges associated with daily adjustments and disputes that are regularly calculated by the ISO Settlement system will be included in the ISO's determinations of Estimated Aggregate Liability as the charges are calculated.

12.1.5A.3.2 FERC Refund Orders.

The ISO will assess its ability to reasonably calculate the charges associated with a refund before the ISO's Settlement system is re-run. If the ISO can reasonably apportion the refund charges to specific Market Participants, it will include the amounts in its calculation of Estimated Aggregate Liability for those Market Participants and will request Financial Security from them accordingly. If the ISO determines that complexities of a FERC refund order preclude the ISO from reasonably being able to include refunds in its calculation of Estimated Aggregate Liability, the ISO will not request Financial Security associated with the required refunds until the refunds are processed through the ISO Settlement system. However, if feasible, the ISO will make available to Market Participants, for informational purposes only, an aggregate forecast of the effect that providing the refunds will have on the ISO's calculation of Estimated Aggregate Liability.

12.1.5A.3.3 ISO ADR Procedures.

The ISO will handle transactions associated with the ISO ADR Procedures in the same manner as transactions associated with refunds provided pursuant to Section 12.1.5A.3.2.

12.1.5A.4 FTR Auction Financial Security Requirements.

The credit requirements related to participation in the ISO's annual Firm Transmission Rights (FTR) auction shall be the same as those for other market obligations. Auction requirements are set forth in the FTR Bidders Manual published annually by the ISO. A FTR Bidder's Aggregate Credit Limit must be sufficient to not only cover ongoing estimated liabilities but also the liabilities resulting from potential winning bids. Each FTR Bidder may choose to designate a portion of their Unsecured Credit Limit and/or posted Financial Security specifically for the FTR auction by notifying the ISO of the FTR Bidder's intent. Alternatively, the FTR Bidder may choose to post additional Financial Security solely to cover their participation in the FTR auction by notifying the ISO of the purpose for the additional Financial Security.

12.2 Review of Creditworthiness.

The ISO may review the creditworthiness of any Market Participant or FTR Bidder which delays or defaults in making payments due under the ISO Tariff and, as a consequence of that review, may require such Market Participant or FTR Bidder, whether or not it an Unsecured Credit Limit, to provide credit support in the form of any of the following types of Financial Security:

(a) an irrevocable and unconditional letter of credit by a bank or financial institution reasonably acceptable to the ISO;

(b) a cash deposit standing to the credit of an interest-bearing escrow account maintained at a bank or financial institution designated by the ISO;

(c) an irrevocable and unconditional surety bond posted by an insurance company reasonably acceptable to the ISO;

(d) a payment bond certificate in the name of the ISO from a financial institution designated by the ISO; or

(e) a prepayment to the ISO.

The ISO may require the Market Participant or FTR Bidder to maintain such Financial Security for at least one (1) year from the date of such delay or default.

12.3 Posting and Releases of Financial Security.

Each Market Participant or FTR Bidder required to provide a Financial Security Amount under Section 12.1.2 shall notify the ISO of the initial Financial Security Amount that it wishes to provide at least fifteen (15) days in advance and shall ensure that the ISO has received such Financial Security Amount prior to the date the Market Participant commences activity through the ISO, or the date the FTR Bidder participates in the applicable auction of FTRs. A Market Participant or FTR Bidder may at any time increase its Financial Security Amount by providing additional Financial Security in accordance with Section 12.1.2. A Market Participant or FTR Bidder may request that its Financial Security Amount be reduced or released by making its request not fewer than fifteen (15) days prior to the date on which the reduction ore release is requested to occur. The ISO shall evaluate the request and inform the Market Participant or FTR Bidder within ten (10) Business Days either that a reduction or release of the Financial Security Amount is permissible, that a reduction or release of the Financial Security Amount is impermissible, or that the ISO requires more information from the Market Participant or FTR Bidder in order to make its determination. The ISO may decline to reduce or release a Financial Security Amount or may release a lesser amount for any of the following reasons:

(a) The Estimated Aggregate Liability for the Market Participant or FTR Bidder cannot be accurately determined due to a lack of supporting settlement charge information.

(b) The most recent liabilities of the Market Participant or FTR Bidder are volatile to a significant degree and a reduction or release of the Financial Security Amount would present a high likelihood that, after the Financial Security Amount was reduced or released, the Estimated Aggregate Liability for the Market Participant or FTR Bidder, as calculated by the ISO, would exceed its Aggregate Credit Limit.

(c) The Market Participant has provided notice or otherwise demonstrated that it is terminating or significantly reducing its participation in the ISO markets. The ISO may retain a portion of the Financial Security Amount to ensure that the Market Participant is adequately secured with respect to pending liabilities that relate to settlement re-runs or other liabilities for which the Market Participant may be responsible under this ISO Tariff.

12.4 Calculation of Ongoing Financial Security Requirements.

Following the date on which a Market Participant commences trading, if the Market Participant's Estimated Aggregate Liability, as calculated by the ISO, at any time exceeds its Aggregate Credit Limit, the ISO shall direct the Market Participant to post an additional Financial Security Amount within five (5) Business Days that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability. The ISO shall also notify a Market Participant if at any time its Estimated Aggregate Liability exceeds 90% of its Aggregate Credit Limit. For the purposes of calculating the Market Participant's Estimated Aggregate Liability, the ISO shall include (1) outstanding charges for Trading Days for which Settlement data is available, and (2) an estimate of charges for Trading Days for which Settlement data is not yet available. To estimate charges for Trading Days for which Settlement data is not yet available, the ISO will consider available historical Settlement data, and other available operational and market data as described in the ISO Credit Policy & Procedures Guide posted on the ISO Home Page.

12.4.1 Review of an ISO Request for an Additional Financial Security Amount.

A Market Participant has five (5) Business Days to review an ISO request for additional Financial Security and submit proposed changes that must be agreed to by the ISO. Within the five (5) Business Days, the Market Participant must either demonstrate to the ISO's satisfaction that the ISO's Financial Security request is entirely or partially unnecessary, or post the required Financial Security Amount calculated by the ISO. If the ISO and the Market Participant are unable to agree on the appropriate level of Financial Security during the five (5) Business Day review period, the Market Participant must post the additional Financial Security and may continue with the dispute process described in Section 12.4.2. Any excess Financial Security amounts will be returned to the Market Participant if the dispute process finds in favor of the Market Participant.

12.4.2 Dispute Process Regarding an ISO Request for an Additional Security Amount.

Market Participants may dispute the Estimated Aggregate Liability calculated by the ISO and, as a result, the ISO may reduce or cancel a requested Financial Security adjustment. The following steps are required for a Market Participant to dispute a Financial Security request resulting from the ISO's calculation of Estimated Aggregate Liability:

(1) Request by the Market Participant to review the ISO calculation.

(2) A reasonable and compelling situation presented, as determined by the Market Participant's ISO client representative.

(3) Documentation of facts and circumstances that evidence that the ISO's calculation of Estimated Aggregate Liability results in an excessive and unwarranted Financial Security posting requirement.

(4) Approval by the ISO Manager and/or Director of Customer Services and Industry Affairs and approval by the ISO Treasurer.

(5) The ISO may decline to adjust the initial Estimated Aggregate Liability, as calculated by the ISO, if the Market Participant has had Financial Security shortfalls in the past 12 months (*i.e.*, it has been shown that the Market Participant's Aggregate Credit Limit at times during the preceding 12 months has been insufficient to cover the Market Participant's Estimated Aggregate Liability).

In no such case shall an ISO request for increased Financial Security remain outstanding for more than five (5) Business Days. Either the above process is to be completed within five (5) Business Days from the date of the ISO request for additional Financial Security, or the Market Participant is to post additional Financial Security within the five (5) Business Days and continue this process, which may result in a return of posted Financial Security back to the Market Participant if the results of the dispute process are found to favor the Market Participant.

Factors for consideration in the event this dispute process is utilized include: weighing the risk of using the lower figure to the potential detriment of market creditors if the Market Participant is under-secured and defaults, against the desire not to impose additional potentially unwarranted costs on a Market Participant; equity and consistency of treatment of Market Participants in the dispute process; and the evidentiary value of the information provided by the Market Participant in the dispute process.

12.5 ISO Enforcement Actions Regarding Under-Secured Market Participants.

If a Market Participant's Estimated Aggregate Liability, as calculated by the ISO, at any time exceeds its Aggregate Credit Limit, the ISO may take any or all of the following actions:

(a) The ISO may withhold a pending payment distribution.

(b) The ISO may limit trading, which may include rejection of Schedules and/or limiting other ISO market activity, including limiting eligibility to participate in a CRR Allocation or CRR Auction. In such case, the ISO shall notify the Market Participant of its action and the Market Participant shall not be entitled to participate in the ISO's markets or CRR Auctions or submit further Schedules or otherwise participate in the ISO's markets until the Market Participant posts an additional Financial Security Amount that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability.

(c) The ISO may require the Market Participant to post an additional Financial Security Amount in lieu of an Unsecured Credit Limit for a period of time.

(d) The ISO may restrict, suspend, or terminate the Market Participant's CRR Entity Agreement or Service Agreement.

(e) The ISO may resell the CRR Holder's CRRs in whole or in part, including any Long Term CRRs, in a subsequent CRR Auction or bilateral transaction, as appropriate.

(f) The ISO will not implement the transfer of a CRR if the transferee or transferor has an Estimated Aggregate Liability in excess of their Aggregate Credit Limit.

In addition, the ISO may restrict or suspend a Market Participant's right to schedule or require the Market Participant to increase its Financial Security Amount if at any time such Market Participant's potential additional liability for Imbalance Energy and other ISO charges is determined by the ISO to be excessive by comparison with the likely cost of the amount of Energy scheduled by the Market Participant.

12.6 Credit Obligations Applicable to CRRs.

12.6.1 Credit Requirements for CRR Allocations.

Subject to applicable requirements of Section 36.9.2 concerning the prepayment of Wheeling Access Charges, Load-Serving Entities eligible to participate in any CRR Allocation are not required to provide additional Financial Security in advance of a CRR Allocation.

12.6.2 Credit Requirements for CRR Auctions.

To establish available credit for participating in any CRR Auction, each Candidate CRR Holder must have an Unsecured Credit Limit or have provided Financial Security in a form consistent with Section 12.1.2 of this ISO Tariff. Each Candidate CRR Holder that participates in a CRR Auction shall ensure that its Aggregate Credit Limit in excess of its Estimated Aggregate Liability is the greater of $500,000 or the sum of the absolute values of all of its bids for CRRs submitted in the relevant CRR Auction. A Candidate CRR Holder that fails to satisfy this requirement shall not be permitted to participate in the relevant CRR Auction.

12.6.3 Credit Requirements for the Holding of CRRs.

12.6.3.1 Credit Requirements Generally.

(a) Each CRR Holder, whether it obtains CRRs through a CRR Allocation or a CRR Auction, must maintain an Aggregate Credit Limit in excess of its Estimated Aggregate Liability including the credit requirement of the CRR portfolio determined as described in this Section 12.6.3. CRR Holders obtaining CRRs in the initial CRR Allocation will be required to comply with the credit requirements associated with such CRRs as determined by the ISO after completion of the initial CRR Auction. The ISO shall issue a market notice after completion of the initial CRR Auction to announce that CRR Holders obtaining CRRs in the initial CRR Allocation must comply with such credit requirements.

(b) Each CRR Holder shall be required to ensure that its Aggregate Credit Limit is sufficient to satisfy the credit requirements described in this Section 12.6.3. CRRs are evaluated on a portfolio basis as follows. If a CRR Holder owns more than one CRR, such CRR Holder shall be subject to an overall credit requirement that is equal to the sum of the individual credit requirements applicable to each of the CRRs held by such CRR Holder. If this sum is positive, the amount will be added to the CRR Holder's Estimated Aggregate Liability. However, if the sum is negative, the CRR Holder's Estimated Aggregate Liability shall not be reduced.

(c) The ISO shall reevaluate the credit requirements for holding CRRs, and shall adjust the credit requirements accordingly, not less than monthly. The ISO may adjust the credit requirements for holding CRRs with terms of one year or less more frequently than monthly at the ISO's discretion to account for changes in the monthly auction prices for CRRs. The ISO may also adjust the credit requirements for holding Long Term CRRs annually to reflect the number of years remaining in the term of any Long Term CRR, to reflect the changes in auction prices of one-year CRRs in annual auctions, and to reflect updates to Credit Margins based on actual Locational Marginal Price data derived from market operations.

(d) In cases where the ownership of a CRR is to be transferred through either the Secondary Registration System or through load migration, the ISO shall evaluate and adjust the credit requirements for both the current owner of the CRR and the prospective owner of the CRR as appropriate prior to the transfer. If additional Financial Security is required from either the current or prospective owner, the transfer will not be completed until such Financial Security has been provided to and accepted by the ISO.

12.6.3.2 Calculation of the Credit Amount Required to Hold a CRR With a Term of One Year or Less.

Each CRR Holder that holds a CRR with a term of one year or less shall be subject to a credit requirement ($/MW) equal to the negative of the most recent CRR Auction Price of such CRR plus the Credit Margin for such CRR.

12.6.3.3 Calculation of the Credit Amount Required to Hold a Long Term CRR.

Each CRR Holder that holds a Long Term CRR shall be subject to a credit requirement ($/MW) equal to (i) the negative of the most recent CRR Auction Price of a CRR with the same source and sink as the Long Term CRR but with only a one-year term, plus (ii) the Credit Margin calculated for the one-year CRR. If there is less than one year remaining in the term of a Long Term CRR, the credit requirement shall be determined pursuant to Section 12.6.3.2.

12.6.3.4 Calculation of Credit Margin.

The Credit Margin ($/MW) for a CRR is equal to (i) the Expected Congestion Revenue minus (ii) the Fifth Percentile Congestion Revenue of such CRR. Both values will be based on the probability distribution of Congestion revenue of such CRR calculated using historical Locational Marginal Price data, when available, and proxy values, including data taken from Locational Marginal Price studies conducted by the ISO, until such time as historical Locational Marginal Price data is available, with the details of such calculation published in a Business Practice Manual. The ISO may reassess its determinations regarding the Credit Margin determination at any time and shall require additional Financial Security if the reassessment results in an increase in a CRR Holder's Estimated Aggregate Liability that is not covered by a CRR Holder's Aggregate Credit Limit (consisting of the CRR Holder's Unsecured Credit Limit and/or Financial Security).

13 DISPUTE RESOLUTION.

13.1 Applicability.

13.1.1 General Applicability.

Except as limited below or otherwise as limited by law (including the rights of any party to file a complaint with FERC under the relevant provisions of the FPA), the ISO ADR Procedures shall apply to all disputes between parties which arise under the ISO Documents except where the decision of the ISO is stated in the provisions of this ISO Tariff to be final. The ISO ADR Procedures shall not apply to:

13.1.1.1 Disputes arising under contracts which pre-date the ISO Operations Date, except as the disputing parties may otherwise agree;

13.1.1.2 Disputes as to whether rates and charges set forth in this ISO Tariff are just and reasonable under the FPA.

13.1.2 Disputes Involving Government Agencies.

13.1.2.1 If a party to a dispute is a government agency the procedures herein which provide for the resolution of claims and arbitration of disputes are subject to any limitations imposed on the agency by law, including but not limited to the authority of the agency to effect a remedy. If the governmental agency is a federal entity, the procedures herein shall not apply to disputes involving issues arising under the United States Constitution.

13.1.3 Injunctive and Declaratory Relief.

Where the court having jurisdiction so determines, use of the ISO ADR Procedures shall not be a condition precedent to a court action for injunctive relief nor shall the provisions of California Code of Civil Procedures sections 1281 et seq. apply to such court actions.

13.2 Negotiation and Mediation.

13.2.1 Negotiation.

The ISO and Market Participants (party or parties) shall make good-faith efforts to negotiate and resolve any dispute between them arising under ISO Documents prior to invoking the ISO ADR Procedures outlined herein. Each party shall designate an individual with authority to negotiate the matter in dispute to participate in such negotiations.

13.2.2 Statement of Claim.

In the event a dispute is not resolved through such good-faith negotiations, any one of the parties may submit a statement of claim, in writing, to each other disputing party, the ISO ADR Committee, and the ISO Governing Board, which submission shall commence the ISO ADR Procedures. The statement of claim shall set forth in reasonable detail (i) each claim, (ii) the relief sought, including the proposed award, if applicable, (iii) a summary of the grounds for such relief and the basis for each claim, (iv) the parties to the dispute, and (v) the individuals having knowledge of each claim. The other parties to the dispute shall similarly submit their respective statements of claim within fourteen (14) days of the date of the initial statement of claim or such longer period as the chair of the ISO ADR Committee may permit following an application by the responding party. If any responding party wishes to submit a counterclaim in response to the statement of claim, it shall be included in such party's responsive statement of claim. A summary of the statements of claim shall be published by the ISO in the ISO newsletter or WEnet, and any other method adopted by the ISO ADR Committee. No Market Participant shall be considered as having received notice of a claim decided or relief granted by a decision made under these procedures unless the summary of the statements of claim published by the ISO includes such claim or relief.

13.2.3 Selection of Mediator.

After submission of the statements of claim, the parties may request mediation, if at least 75% of the disputing parties so agree, except that where a dispute involves three parties, at least two of the parties must agree to mediation. If the parties agree to mediate, the chair of the ISO ADR Committee shall distribute to the parties by facsimile or other electronic means a list containing the names of at least seven prospective mediators with mediation experience, or with technical or business experience in the electric power industry, or both, as he or she shall deem appropriate to the dispute. The parties shall either agree upon a mediator from the list provided or from any alternative source, or alternate in striking names from the list with the last name on the list becoming the mediator. The first party to strike off a name from the list shall be determined by lot. The parties shall have seven days from the date of receipt of the ISO ADR Committee chair's list of prospective mediators to complete the mediator selection process and appoint the mediator, unless the time is extended by mutual agreement. The mediator shall comply with the requirements of Section 13.3.2.

13.2.4 Mediation.

The mediator and representatives of the disputing parties, with authority to settle the dispute, shall within fourteen (14) days after the mediator's date of appointment schedule a date to mediate the dispute. Matters discussed during the mediation shall be confidential and shall not be referred to in any subsequent proceeding. With the consent of all disputing parties, a resolution may include referring the dispute directly to a technical body (such as a WECC technical advisory panel) for resolution or an advisory opinion, or referring the dispute directly to FERC. The ISO shall publish notice of the referral of the dispute in the ISO newsletter or WEnet, and any other method adopted by the ISO ADR Committee.

13.2.5 Demand for Arbitration.

If the disputing parties have not succeeded in negotiating a resolution of the dispute within thirty (30) days of the initial statement of claim or, if within that period the parties agreed to mediate, within thirty (30) days of the parties first meeting with the mediator, such parties shall be deemed to be at impasse and any such disputing party may then commence the arbitration process, unless the parties by mutual agreement agree to extend the time. A party seeking arbitration shall provide notice of its demand for arbitration to the other disputing parties, the ISO ADR Committee and the ISO Governing Board, which shall publish notice of such demand in the ISO newsletter or electronic bulletin board, and any other method adopted by the ISO ADR Committee.

13.3 Arbitration.

13.3.1 Selection of Arbitrator.

13.3.1.1 Disputes Under $1,000,000.

Where the total amount of claims and counterclaims in controversy is less than $1,000,000 (exclusive of costs and interest), the disputing parties shall select an arbitrator from a list containing the names of at least 10 qualified individuals supplied by the ISO ADR Committee, or if the ISO is a party to the dispute, the names of at least ten (10) qualified individuals supplied by the American Arbitration Association within 14 days following submission of the demand for arbitration. If the parties cannot agree upon an arbitrator within the stated time, they shall take turns striking names from the list of proposed arbitrators. The first party to strike-off a name shall be determined by lot. This process shall be repeated until one name remains on the list, and that individual shall be the designated arbitrator.

13.3.1.2 Disputes of $1,000,000 or Over.

Where the total amount of claims and counterclaims in controversy is $1,000,000 or more (exclusive of interest and costs), the disputing parties may agree on any person to serve as a single arbitrator, or shall endeavor in good faith to agree on a single arbitrator from a list of ten (10) qualified individuals provided by the ISO ADR Committee, or if the ISO is a party to the dispute, the names of at least ten (10) qualified individuals supplied by the American Arbitration Association within fourteen (14) days following submission of the demand for arbitration. If the parties are unable to agree on a single arbitrator within the stated time, the party or parties demanding arbitration, and the party or parties responding to the demand for arbitration, shall each designate an arbitrator. Each designation shall be from the ISO ADR Committee list of arbitrators no later than the tenth (10th) day thereafter. The two arbitrators so chosen shall then choose a third arbitrator.

13.3.2 Disclosures Required of Arbitrators.

The designated arbitrator(s) shall be required to disclose to the parties any circumstances which might preclude him or her from rendering an objective and impartial determination. Each designated arbitrator shall disclose:

13.3.2.1 Any direct financial or personal interest in the outcome of the arbitration;

13.3.2.2 Any information required to be disclosed by California Code of Civil Procedure Section 1281.9.; and

13.3.2.3 Any existing or past financial, business, professional, or personal interest that are likely to affect impartiality or might reasonably create an appearance of partiality or bias. The designated arbitrator shall disclose any such relationships that he or she personally has with any party or its counsel, or with any individual whom they have been told will be a witness. They should also disclose any such relationship involving members of their families or their current employers, partners, or business associates. All designated arbitrators shall make a reasonable effort to inform themselves of any interests or relationships described above. The obligation to disclose interests, relationships, or circumstances that might preclude an arbitrator from rendering an objective and impartial determination is a continuing duty that requires the arbitrator to disclose, at any stage of the arbitration, any such interests, relationships, or circumstances that arise, or are recalled or discovered. If, as a result of the continuing disclosure duty, an arbitrator makes a disclosure which is likely to affect his or her partiality, or might reasonably create an appearance of partiality or bias or if a party independently discovers the existence of such circumstances, a party wishing to object to the continuing use of the arbitrator must provide written notice of its objection to the other parties within ten (10) days of receipt of the arbitrator's disclosure or the date of a party's discovery of the circumstances giving rise to that party's objection. Failure to provide such notice shall be deemed a waiver of such objection. If a party timely provides a notice of objection to the continuing use of the arbitrator the parties shall attempt to agree whether the arbitrator should be dismissed and replaced in the manner described in Section 13.3.1. If within ten (10) days of a party's objection notice the parties have not agreed how to proceed the matter shall be referred to the ISO ADR Committee for resolution.

13.3.3 **Arbitration Procedures.**

The ISO ADR Committee shall compile and make available to the arbitrator and the parties standard procedures for the arbitration of disputes, which procedures (i) shall include provision, upon good cause shown, for intervention or other participation in the proceeding by any party whose interests may be affected by its outcome, (ii) shall conform to the requirements specified herein, and (iii) may be modified or adopted for use in a particular proceeding as the arbitrator deems appropriate, in accordance with Section 13.3.4. The procedures adopted by the ISO ADR Committee shall be based on the latest edition of the American Arbitration Association Commercial Arbitration Rules, to the extent such rules are not inconsistent with this Section 13. Except as provided herein, all parties shall be bound by such procedures.

13.3.4 Modification of Arbitration Procedures.

In determining whether to modify the standard procedures for use in the pending matter, the arbitrator shall consider (i) the complexity of the dispute, (ii) the extent to which facts are disputed, (iii) the extent to which the credibility of witnesses is relevant to a resolution, (iv) the amount in controversy, and (v) any representations made by the parties. Alternatively, the parties may, by mutual agreement, modify the standard procedures. In the event of a disagreement between the arbitrator and the agreement of the parties regarding arbitration procedures to be utilized, the parties' agreement shall prevail.

13.3.5 Remedies.

13.3.5.1 Arbitrator's Discretion.

The arbitrator shall have the discretion to grant the relief sought by a party, or determine such other remedy as is appropriate, unless the parties agree to conduct the arbitration "baseball" style. Unless otherwise expressly limited herein, the arbitrator shall have the authority to award any remedy or relief available from FERC, or any other court of competent jurisdiction. Where any ISO Document leaves any matter to be agreed between the parties at some future time and provides that in default of agreement the matter shall be referred to the ISO ADR Procedures, the arbitrator shall have authority to decide upon the terms of the agreement which, in the arbitrator’s opinion, it is reasonable that the parties should reach, having regard to the other terms of the ISO Document concerned and the arbitrator’s opinion as to what is fair and reasonable in all the circumstances.

13.3.5.2 "Baseball" Arbitration.

If the parties agree to conduct the arbitration "baseball" style, the parties shall submit to the arbitrator and exchange with each other their last best offers in the form of the award they consider the arbitrator should make, not less than seven (7) days in advance of the date fixed for the hearing, or such other date as the arbitrator may decide. If a party fails to submit its last best offer in accordance with this Section, that party shall be deemed to have accepted the offer proposed by the other party. The arbitrator shall be limited to awarding only one of the proposed offers, and may not determine an alternative or compromise remedy.

13.3.6 Summary Disposition.

The procedures for arbitration of a dispute shall provide a means for summary disposition of a demand for arbitration, or a response to a demand for arbitration, that in the reasoned opinion of the arbitrator does not have a good faith basis in either law or fact. If the arbitrator determines that a demand for arbitration or response to a demand for arbitration does not have a good faith basis in either law or fact, the arbitrator shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator to the prevailing party. A determination made under this Section is subject to appeal pursuant to Section 13.4.

13.3.7 Discovery Procedures.

The procedures for the arbitration of a dispute shall include adequate provision for the discovery of relevant facts, including the taking of testimony under oath, production of documents and other things, the presentation of evidence, the taking of samples, conducting of tests, and inspection of land and tangible items. The nature and extent of such discovery shall be determined as provided herein and shall take into account (i) the complexity of the dispute, (ii) the extent to which facts are disputed, (iii) the extent to which the credibility of witnesses is relevant to a resolution, and (iv) the amount in controversy. The forms and methods for taking such discovery shall be as described in the Federal Rules of Civil Procedure, except as modified pursuant to Section 13.3.4.

13.3.8 Evidentiary Hearing.

The arbitration procedures shall provide for an evidentiary hearing, with provision for the cross-examination of witnesses, unless all parties consent to the resolution of the matter on the basis of a written record. The forms and methods for taking evidence shall be determined by the arbitrator(s) and modified pursuant to Section 13.3.4. The arbitrator may require such written or other submissions from the parties as he or she may deem appropriate, including submission of direct and rebuttal testimony of witnesses in written form. The arbitrator may exclude any evidence that is irrelevant, immaterial, unduly repetitious or prejudicial, or privileged. The arbitrator shall compile a complete evidentiary record of the arbitration which shall be available to the parties on its completion upon request.

13.3.9 Confidentiality.

Subject to the other provisions of this ISO Tariff, any party may claim that information contained in a document otherwise subject to discovery is "Confidential" if such information would be so characterized under the Federal Rules of Evidence. The party making such claim shall provide to the arbitrator in writing the basis for its assertion. If the claim of confidentiality is confirmed by the arbitrator, he or she shall establish requirements for the protection of such documents or other information designated as "Confidential" as may be reasonable and necessary to protect the confidentiality and commercial value of such information. Any party disclosing information in violation of these provisions or requirements established by the arbitrator, unless such disclosure is required by federal or state law or by a court order, shall thereby waive any right to introduce or otherwise use such information in any judicial, regulatory, or other legal or dispute resolution proceeding, including the proceeding in which the information was obtained.

13.3.10 Timetable.

Promptly after the appointment of the arbitrator, the arbitrator shall set a date for the issuance of the arbitration decision, which shall be no later than six months (or such date as the parties and the arbitrator may agree) from the date of the appointment of the arbitrator, with other dates, including the dates for an evidentiary hearing or other final submissions of evidence, set in light of this date. The date for the evidentiary hearing or other final submission of evidence shall not be changed, absent extraordinary circumstances. The arbitrator shall have the power to impose sanctions, including dismissal of the proceeding, for dilatory tactics or undue delay in completing the arbitration proceedings.

13.3.11 Decision.

13.3.11.1 Except as provided below with respect to "baseball" style arbitration, the arbitrator shall issue a written decision granting the relief requested by one of the parties, or such other remedy as is appropriate, if any, and shall include findings of fact and law. The arbitration decision shall be based on (i) the evidence in the record, (ii) the terms of the relevant ISO Documents, (iii) applicable United States federal law, including the FPA and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) applicable state law. Additionally, the arbitrator may consider relevant decisions in previous arbitration proceedings. A summary of the disputed matter and the arbitrator's decision shall be published in an ISO newsletter or electronic bulletin board and any other method adopted by the ISO ADR Committee, and maintained by the ISO ADR Committee.

13.3.11.2 In arbitration conducted "baseball" style, the arbitrator shall issue a written decision adopting one of the awards proposed by the parties, and shall include findings of fact and law. The arbitration decision shall be based on (i) the evidence in the record, (ii) the terms of the relevant ISO Documents, (iii) applicable United States federal law, including the FPA and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) applicable state law. If the arbitrator concludes that no proposed award is consistent with the factors enumerated in (i) through (iv) above, or addresses all of the issues in dispute, the arbitrator shall specify how each proposed award is deficient and direct that the parties submit new proposed awards that cure the identified deficiencies. A summary of the disputed matter and the arbitrator's decision shall be published in an ISO newsletter or electronic bulletin board, and any other method adopted by the ISO ADR Committee. An award shall not be deemed to be precedential.

13.3.11.3 Where a panel of arbitrators is appointed pursuant to Section 13.3.1.2, a majority of the arbitrators must agree on the decision.

13.3.12 Compliance.

Unless the arbitrator's decision is appealed under Section 13.4, the disputing parties shall, upon receipt of the decision, immediately take whatever action is required to comply with the award to the extent the award does not require regulatory action. An award that is not appealed shall be deemed to have the same force and effect as an order entered by the FERC or any court of competent jurisdiction.

13.3.13 Enforcement.

Following the expiration of the time for appeal of an award pursuant to Section 13.4.3, any party may apply to FERC or any court of competent jurisdiction for entry and enforcement of judgment based on the award.

13.3.14 Costs.

The costs of the time, expenses, and other charges of the arbitrator shall be borne by the parties to the dispute, with each side on an arbitrated issue bearing its pro-rata share of such costs, and each party to an arbitration proceeding bearing its own costs and fees. If the arbitrator determines that a demand for arbitration or response to a demand for arbitration was made in bad faith, the arbitrator shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator to the prevailing party. Notwithstanding the above, at the discretion of the arbitrator, the winning party in any dispute which has resulted in the enforcement of an important right affecting the public interest shall not be required to pay any of the costs of the arbitrator and may recover such of its own reasonable attorney fees, expert witness fees and other reasonable costs from the losing party to the dispute if (a) a significant benefit, whether pecuniary or non-pecuniary, has been conferred on the general public, (b) the necessity and financial burden of private enforcement are such as to make the award appropriate, and (c) such fees should not, in the interest of justice, be paid out of the recovery.

13.4 Appeal of Award.

13.4.1 Basis for Appeal.

A party may apply to the FERC or any court of competent jurisdiction to hear an appeal of an arbitration award only upon the grounds that the award is contrary to or beyond the scope of the relevant ISO

Documents, United States federal law, including, without limitation, the FPA, and any FERC regulations and decisions, or state law. Appeals shall, unless otherwise ordered by FERC or the court of competent jurisdiction, conform to the procedural limitations set forth in this Section 13.4.

13.4.2 Appellate Record.

The parties intend that FERC or the court of competent jurisdiction should afford substantial deference to the factual findings of the arbitrator. No party shall seek to expand the record before the FERC or court of competent jurisdiction beyond that assembled by the arbitrator, except (i) by making reference to legal authority which did not exist at the time of the arbitrator's decision, or (ii) if such party contends the decision was based upon or affected by fraud, collusion, corruption, misconduct or misrepresentation.

13.4.3 Procedures for Appeals.

13.4.3.1 If a party to an arbitration desires to appeal an award, it shall provide a notice of appeal to the ISO Governing Board, all parties and the arbitrator within 14 days following the date of the award. The appealing party must likewise provide notice to the ISO ADR Committee, which shall publish notice of the appeal in an ISO newsletter or on WEnet, and any other method adopted by the ISO ADR Committee.

Within ten (10) days of the filing of the notice of appeal, the appealing party must file an appropriate application, petition or motion with the FERC to trigger review under the FPA or with a court of competent jurisdiction. Such filing shall state that the subject matter has been the subject of an arbitration pursuant to the relevant ISO Document.

13.4.3.2 Within 30 days of filing the notice of appeal (or such period as FERC or the court of competent jurisdiction may specify) the appellant shall file the complete evidentiary record of the arbitration and a copy of the award with FERC or with the court of competent jurisdiction. The appellant shall serve copies of a description of all materials included in the submitted evidentiary record.

13.4.4 Award Implementation.

Implementation of the award shall be deemed stayed pending an appeal unless and until, at the request of a party, the FERC or the court of competent jurisdiction to which an appeal has been filed, issues an order dissolving, shortening, or extending such stay. However, a summary of each appeal shall be published in an ISO newsletter or electronic bulletin board, and any other method adopted by the ISO ADR Committee.

13.4.5 Judicial Review of FERC Orders.

FERC orders resulting from appeals shall be subject to judicial review pursuant to the FPA.

13.5 Allocation of Awards Payable by or to the ISO.

13.5.1 Allocation of an Award.

If the ISO must pay an award to a party pursuant to good faith negotiations or the ISO ADR Procedures, the ISO will recover the amount of the award from Market Participants and Scheduling Coordinators. If the ISO receives an award from a party pursuant to good faith negotiations or the ISO ADR Procedures, the ISO will flow back the amount of the award to Market Participants and Scheduling Coordinators.

13.5.2 Timing of Adjustments.

Upon determination that an award is payable by or to the ISO pursuant to good faith negotiations or the ISO ADR Procedures, the ISO shall calculate the amounts payable to and receivable from the party, Market Participants, and Scheduling Coordinators, as soon as reasonably practical, and shall show any required adjustments as a debit or a credit in a subsequent Preliminary Settlement Statement or, in the case of an amount payable by the ISO to a party, as soon as the ISO and that party may agree.

13.5.3 Method of Allocation.

13.5.3.1 Allocation to Market Participants.

The ISO will use best efforts to determine which Market Participant(s) is or are responsible for and/or benefit from payment of an award by or to the ISO and to allocate receipt of or payment for the award equitably to such Market Participant(s). In undertaking the allocation, the ISO shall consider the extent of a Market Participant's participation in affected markets and the ISO Tariff in effect on the applicable Trading Day(s), and may consider any other relevant factor, including but not limited to, applicable contracts.

13.5.3.2 Residual Amounts.

Any awards for which the ISO is unable to identify Market Participants in accordance with 13.5.3.1 and any award amounts that the ISO is unable to collect that are not covered by Section 11.16.1 will be allocated to all Scheduling Coordinators through Neutrality Adjustments.

14 FORCE MAJURE INDEMNIFICATION AND LIMITATIONS ON LIABILITY.

14.1 Uncontrollable Forces.

14.1.1 An Uncontrollable Force means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm, flood, earthquake, explosion, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond the reasonable control of the ISO or Market Participant which could not be avoided through the exercise of Good Utility Practice. Neither the ISO nor a Market Participant will be considered in default of any obligation under this ISO Tariff if prevented from fulfilling that obligation due to the occurrence of an Uncontrollable Force.

14.1.2 In the event of the occurrence of an Uncontrollable Force, which prevents the ISO or a Market Participant from performing any of its obligations under this ISO Tariff, the affected entity shall (i) if it is the ISO, immediately notify the Market Participants in writing of the occurrence of such Uncontrollable Force and, if it is a Market Participant, immediately notify the ISO in writing of the occurrence of such Uncontrollable Force, (ii) not be entitled to suspend performance of its obligations under this ISO Tariff in any greater scope or for any longer duration than is required by the Uncontrollable Force, (iii) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform and resume full performance of its obligations hereunder, (iv) in the case of the ISO, keep the Market Participants apprised of such efforts, and in the case of the Market Participants, keep the ISO apprised of such efforts, in each case on a continual basis and (v) provide written notice of the resumption of its performance of its obligations hereunder.

Notwithstanding any of the foregoing, the settlement of any strike, lockout or labor dispute constituting an Uncontrollable Force shall be within the sole discretion of the entity involved in such strike, lockout or labor dispute and the requirement that an entity must use its best efforts to mitigate the effects of the Uncontrollable Force and/or remedy its inability to perform and resume full performance of its obligations hereunder shall not apply to strikes, lockouts, or labor disputes.

14.2 Market Participant's Indemnity.

Each Market Participant, to the extent permitted by law, shall indemnify the ISO and hold it harmless against all losses, damages, claims, liabilities, costs or expenses (including legal expenses) arising from any act or omission of the Market Participant except to the extent that they result from the ISO's default under this ISO Tariff or negligence or intentional wrongdoing on the part of the ISO or of its officers, directors or employees.

14.3 Limitation on Liability.

14.3.1 Liability for Damages.

Except as provided for in Section 13.3.14, the ISO shall not be liable in damages to any Market Participant for any losses, damages, claims, liability, costs or expenses (including legal expenses) arising from the performance or non-performance of its obligations under this ISO Tariff, including but not limited to any adjustments made by the ISO in Inter-Scheduling Coordinator Trades, except to the extent that they result from negligence or intentional wrongdoing on the part of the ISO.

14.3.2 Exclusion of Certain Types of Loss.

The ISO shall not be liable to any Market Participant under any circumstances for any consequential or indirect financial loss including but not limited to loss of profit, loss of earnings or revenue, loss of use, loss of contract or loss of goodwill except to the extent that it results from except to the extent that it results from negligence or intentional wrongdoing on the part of the ISO.

14.4 Potomac Economics, Ltd. Limitation Of Liability.

Potomac Economics, Ltd. shall not be liable in damages to any Market Participant for any losses, damages, claims, liability, costs or expenses (including legal expenses) arising from its calculation of reference levels under its Consultant Agreement with the ISO dated as of September 3, 2002, except to the extent that they result from negligence or intentional wrongdoing of Potomac Economics, Ltd.

15 REGULATORY FILINGS.

Any amendment or other modification of any provision of this ISO Tariff must be in writing and approved by the ISO Governing Board in accordance with the bylaws of the ISO. Any such amendment or modification shall be effective upon the date it is permitted to become effective by FERC. Nothing contained herein shall be construed as affecting, in any way, the right of the ISO to furnish its services in accordance with this ISO Tariff, or any tariff, rate schedule or Scheduling Coordinator Agreement which results from or incorporates this ISO Tariff, unilaterally to make an application to FERC for a change in rates, terms, conditions, charges, classifications of service, Scheduling Coordinator Agreement, rule or regulation under FPA Section 205 and pursuant to the FERC's rules and regulations promulgated thereunder. Nothing contained in this ISO Tariff or any Scheduling Coordinator Agreement shall be construed as affecting the ability of any Market Participant receiving service under this ISO Tariff to exercise its rights under Section 206 of the FPA and FERC's rules and regulations thereunder.

16 EXISTING CONTRACTS.

16.1 Existing Contracts for Transmission Service.

16.1.1 In accordance with Section 16.2 each Participating TO and holder of transmission rights under an Existing Contract will work with the ISO to develop operational protocols (which shall be based on existing protocols and procedures to the extent possible) which allow existing contractual rights to be exercised in accordance with Section 16.2 in a way that: (i) maintains the existing scheduling and curtailment priorities under the Existing Contract; (ii) is minimally burdensome to the ISO (i.e., creates the least impact on the ISO's preferred operational protocols, rules and procedures); (iii) to the extent possible, imposes no additional financial burden on either the Participating TO or the contract rights holder (beyond that in the Existing Contract); (iv) consistent with the terms of the Existing Contracts, makes as much transmission capacity not otherwise utilized by the holder of the transmission rights as possible available to the ISO for allocation to Market Participants; (v) is minimally burdensome to the

Participating TO and the holder of the transmission rights from an operational point of view; and (vi) does not require the ISO to interpret or underwrite the economics of the Existing Contract.

16.1.2 The ISO will accept valid Schedules from a Responsible Participating TO that is the Scheduling Coordinator for the Existing Contract rights holders, or from Existing Contract rights holders that are Scheduling Coordinators, or that are represented by a Scheduling Coordinator other than the Responsible Participating TO. Schedules submitted by Scheduling Coordinators to the ISO which include the use of Existing Rights must be submitted in accordance with Section 16.1, Section 16.2, and Section 30.2.7. The ISO may refuse to accept Schedules submitted pursuant to Existing Contracts which do not meet the requirements of the principles, protocols and rules referred to in this Section 16.1 and Section 16.2. The ISO will implement Sections 16.1 and 16.2 with respect to Existing Contracts after the close of the Hour-Ahead Market and in real time.

16.1.3 The ISO will, if requested, advise parties to Existing Contracts regarding the operational aspects of any Existing Contract renegotiations that they undertake.

16.2 ISO Administration of Existing Contracts for Transmission Service.

16.2.1 Continuation of Rights and Obligations of Non-Participating TOs Under Existing Contracts.

16.2.1.1 The transmission service rights and obligations of Non-Participating TOs under Existing Contracts, including all terms, conditions and rates of the Existing Contracts, as they may change from time to time under the terms of the Existing Contracts, will continue to be honored by the parties to those contracts, for the duration of those contracts. For the purpose of Section 16.2, the transmission service rights of Non-Participating TOs are called “Existing Rights.”

16.2.1.2 If a Participating TO is a party to an Existing Contract under which Existing Rights are provided, the Participating TO shall attempt to negotiate changes to the Existing Contract to align the contract’s scheduling and operating provisions with the ISO’s scheduling and operational procedures, rules and protocols, to align operations under the contract with ISO operations, and to minimize the contract parties' costs of administering the contract while preserving their financial rights and obligations as defined in Section 16.2.2.

In addition, the Participating TO shall attempt to negotiate changes to provisions in the Existing Contract to ensure that whenever transmission services under the Existing Contract are used to deliver power to a Market Participant that is subject to Access Charges under this Tariff, no duplicative charge for access to the ISO Controlled Grid will be charged under the Existing Contract. For purposes of such negotiations, there shall be a presumption that any charges in an Existing Contract that were designed to recover the embedded cost of transmission facilities within the ISO Controlled Grid will be fully recovered through the Access Charges established under Section 26.1 of this Tariff.

16.2.1.3 If a Non-Participating TO has an Existing Contract with a Participating TO under which the Non-Participating TO's transmission facilities are subject to use by the Participating TO, the Non-Participating TO's rights to the use and ownership of its facilities shall remain unchanged, regardless of the Participating TO's act of turning over the Participating TO's entitlement to use the Non-Participating TO's facilities to the extent possible to the Operational Control of the ISO.

16.2.1.4 If the parties to an Existing Contract are unable to reach agreement on the changes needed to meet the requirements of Section 16.2.1.2 or Section 16.2.1.3, any disputes related thereto shall be addressed using the dispute resolution provisions of the Existing Contract, including any remedies as are provided by law. The rights of the parties to seek changes or to challenge such changes, under the FPA or as otherwise provided by law, are preserved consistent with the terms of the Existing Contract. Unless and until the necessary changes to the Existing Contract are made, all terms and conditions of the Existing Contracts will continue to be honored by the parties to the contracts.

16.2.1A Conversion of Participating TOs' Rights and Obligations Under Existing Contracts.

16.2.1A.1 Parties who are entitled to transmission service rights under Existing Contracts and who choose to become Participating TOs must, at the time of becoming a Participating TO exercise those rights by converting them to "Converted Rights", which are described in Section 16.2.2. A party who ceases to be a Participating TO at or before the end of the five year period beginning at the ISO Operations Date shall be entitled to resume service under any Existing Contract to which it is then a party, so long as that contract has not expired or been terminated. For the purposes of Sections 16.1 and 16.2, Pacific Gas & Electric Company, Southern California Edison Company and San Diego Gas & Electric Company will be deemed to have converted all rights that they may hold under Existing Contracts to Converted Rights as described in Section 16.2.2 with effect from the ISO Operations Date. Schedules that utilize Converted Rights shall be submitted by a Scheduling Coordinator that has been certified in accordance with Section 4.5.1.

16.2.1A.2 As part of the conversion referred to in Section 16.2.1A.1, modifications to an Existing Contract may be needed. Any required modifications must be agreed upon by all parties to the contract. Failure of the parties to reach agreement on the modifications required under Section 16.2.1A.1 shall be addressed using the dispute resolution provisions of the Existing Contract, including any remedies as are provided by law consistent with the terms of the Existing Contract. The rights of the parties to challenge such changes, under the FPA or as otherwise provided by law, are preserved.

16.2.2 Converted Rights.

16.2.2.1 A recipient of transmission service under an Existing Contract that chooses to become a Participating TO and convert its rights to ISO transmission service, and the Participating TO which provides the transmission service under the Existing Contract shall change the terms and conditions of the contract to provide that:

16.2.2.1.1 The recipient of the transmission service received under an Existing Contract that has converted its rights to ISO transmission service shall turn over Operational Control of its transmission entitlement to the ISO for management by the ISO in accordance with the ISO's scheduling, Congestion Management, curtailment and other ISO Protocols;

16.2.2.1.2 The recipient of the transmission service under an Existing Contract that has converted its rights to ISO transmission service shall obtain all future transmission services within, into (starting at the ISO Controlled Grid), out of, or through the ISO Controlled Grid using the ISO's scheduling and operational procedures and protocols and the ISO Tariff and any applicable TO Tariff, provided that this provision shall not affect the rights, if any, of the contract parties to extend Existing Contracts.

16.2.2.1.3 [Not Used]

16.2.2.1.4 For the capacity represented by its rights, the recipient of firm transmission service under an Existing Contract that has converted its rights to ISO transmission service shall be entitled to receive the Usage Charge revenues for the capacity (and/or alternatives to such revenues, such as physical transmission rights or transmission congestion contracts, should they exist) and all Wheeling revenue credits throughout the term that the capacity is available under the Existing Contract. The recipient of less than firm service shall receive these revenues in proportion to the degree of firmness and the terms and conditions of their service.

16.2.2.1.5 The recipient of the transmission service received under an Existing Contract that has converted its rights to ISO transmission service shall continue to have the obligation to pay the provider of the service for its transmission service at the rates provided in the Existing Contract, as they may change from time to time under the terms of the Existing Contract, or as mutually agreed between the contract

parties, through the term of the contract, subject to the terms and conditions of the contract, including the rights of the parties to the contract to seek unilateral or other changes pursuant to Section 205 or Section 206 of the Federal Power Act and the FERC's Rules and Regulations or as otherwise provided by law.

16.2.2.2 Other aspects of such an Existing Contract may also need to be changed. If the parties to the contract are unable to negotiate such changes, they shall seek appropriate changes through the mechanisms provided within the contract, including the rights, if any, to seek unilateral or other changes pursuant to Section 205 or Section 206 of the Federal Power Act and the FERC's Rules and Regulations or as otherwise provided by law.

16.2.3 ISO Treatment of Non-Participating TOs Existing Rights.

16.2.3.1 For the purposes of Section 16.2, Existing Rights fall into one of three general categories: firm transmission service, non-firm transmission service, and conditional firm transmission service. The parties to an Existing Contract shall notify the ISO which Existing Rights fall into each category, through the operating instructions described in this section and in Section 16.2.4A.

(i) For each Existing Contract, the party providing transmission service (the "Responsible PTO") shall be responsible for the submission of transmission rights/curtailment instructions to the ISO on behalf of the holders of Existing Rights, unless the parties to the Existing Contract agree otherwise. For the purposes of this ISO Tariff, such otherwise agreed party will be acting in the role of Responsible PTO.

(ii) In accordance with the ISO Tariff, the parties to Existing Contracts will attempt to jointly develop and agree on any instructions that will be submitted to the ISO. To the extent there is more than one Participating TO providing transmission service under an Existing Contract or there is a set of Existing Contracts which are interdependent from the point of view of submitting instructions to the ISO involving more than one Participating TO, the relevant Participating TOs will designate a single Participating TO as the Responsible PTO and will notify the ISO accordingly. If no such Responsible PTO is designated by the relevant Participating TOs or the ISO is not notified of such designation, the ISO shall designate one of them as the Responsible PTO and notify the relevant Participating TOs accordingly.

(iii) The parties to an Existing Contract shall also be responsible to submit to the ISO any other necessary operating instructions based on their contract interpretations needed by the ISO to enable the ISO to perform its duties.

16.2.3.1.1 The ISO will have no role in interpreting Existing Contracts. The parties to an Existing Contract will, in the first instance, attempt jointly to agree on any operating instructions that will be submitted to the ISO. In the event that the parties to the Existing Contract cannot agree upon the operating instructions submitted by the parties to the Existing Contract, the dispute resolution provisions of the Existing Contract, if applicable, shall be used to resolve the dispute; provided that, until the dispute is resolved, and unless the Existing Contract specifies otherwise, the ISO shall implement the Participating TO's operating instructions. If both parties to an Existing Contract are Participating TOs and the parties cannot agree to the operating instructions submitted by the parties, until the dispute is resolved, and unless the Existing Contract specifies otherwise, the ISO shall implement the operating instructions of the first Participating TO for which the Existing Contract is an Encumbrance.

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

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

16.2.3.4 All contractual provisions that have been communicated to the ISO in writing in accordance with Section 16.2.3.1 by the parties to the Existing Contracts, shall be honored by the ISO and the parties to the Existing Contracts and shall be implemented in accordance with the terms and conditions of the relevant Existing Contracts so notified.

16.2.3.4.1 The holders of Existing Rights will not be responsible for paying Usage Charges related to those rights, nor will they be entitled to receive Usage Charge revenues related to those rights.

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

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

16.2.3.4.4 **[Not Used]**

16.2.3.4.5 Parties with Existing Rights shall continue to pay for Transmission Losses or Ancillary Services requirements in accordance with such Existing Contracts as they may be modified or changed in accordance with the terms of the Existing Contract. Likewise the Participating TOs shall continue to provide Transmission Losses and any other Ancillary Services to the holder of the rights under an Existing Contract as may be required by the Existing Contracts. To the extent that Transmission Losses or Ancillary Service requirements associated with Existing Rights are not the same as those under the

ISO's rules and protocols, the ISO will not charge or credit the Participating TO for any cost differences between the two, but will provide the parties to the Existing Contracts with details of its Transmission Losses and Ancillary Services calculations to enable them to determine whether the ISO's calculations result in any associated shortfall or surplus and to enable the parties to the Existing Contracts to settle the differences bilaterally or through the relevant TO Tariff. Each Participating TO will be responsible for recovering any deficits or crediting any surpluses associated with differences in assignment of Transmission Loss requirements and/or Ancillary Services requirements, through its bilateral arrangements or its Transmission Owner's Tariff.

16.2.4 ISO Protocols Shall Accommodate Existing Rights.

The ISO will implement the provisions of Section 16.2.3. The objective will be to ensure that under the ISO Tariff, Existing Rights will enjoy the same relative priorities vis-à-vis new, ISO-provided transmission uses, as they would under the Existing Contracts and the FERC Order 888 tariffs. Under the ISO Tariff:

16.2.4A Existing scheduling rules, curtailment priorities and any other relevant terms and conditions associated with the scheduling and day-to-day implementation of transmission rights will be documented in sets of operating instructions provided to the ISO by the parties to the Existing Contracts. The documentation of these operating instructions, and disputes related to these operating instructions, will be handled in accordance with the terms of Section 16.2.3.1.1.

16.2.4A.1 The responsible Participating TO with respect to an Existing Contract or set of interdependent Existing Contracts is required to submit to the ISO, in accordance with the timing requirements of Section 16.2.4A.2 and 16.2.4A.3, the instructions that are necessary to implement the exercise of Existing Rights in accordance with the ISO Tariff. The operating instructions will be submitted to the ISO electronically, by the Responsible PTO, utilizing a form provided by the ISO in a format similar to the one set out in the Standard Template – Transmission Rights/Curtailment Instructions in Appendix M. The instructions will include the following information at a minimum and such other information as the ISO may reasonably require to enable it to carry out its functions under the ISO Tariff and ISO Protocols (the letters below correspond with the letters of the instructions template in the Standard Template – Transmission Rights/Curtailment Instructions in Appendix M:

(a) a unique contract reference number (Existing Contract reference number that will be assigned by the ISO and communicated to the Responsible PTO on the completed instruction and that references a single Existing Contract or a set of interdependent Existing Contracts; the provisions of Section 30.4.2 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 Zones in which the point(s) of receipt and point(s) of delivery are located);

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

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

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

(i) type(s) of service, by rights holder, by Existing Contract (firm, conditional firm, or non-firm), with priorities for firm and conditional firm transmission services indicated in Schedules using Adjustment Bids as described in this ISO Tariff;

(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 Scheduling Coordinator 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 Scheduling Coordinator 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 Section 7.4.12. Any such instructions submitted to the ISO must be clear, unambiguous, and not require the ISO to make any judgments or interpretations as to the meaning intent, results, or purpose of the curtailment procedures or the Existing Contract (otherwise, they will not be accepted by the ISO); and

(p) any special procedures relating to curtailments during emergency conditions. Any such instructions submitted to the ISO must be clear, unambiguous, and not require the ISO to make any judgments or interpretations as to the meaning, intent, results, or purpose of the curtailment procedures or the Existing Contract (otherwise, they will not be accepted by the ISO).

16.2.4A.2 The Responsible PTOs shall submit the operating 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 16.1 or 16.2. The ISO will not accept Schedules which include the use of Existing Rights, unless the Responsible PTO has provided the ISO with the information required in the Transmission Control Agreement and this Section 16.2.4, including transmission rights/curtailment instructions supplied in a form and by means of communication specified by the ISO.

16.2.4A.3 Updates or changes to the operating 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. 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.

16.2.4B To the extent that the operating instructions can be exercised independently of the ISO by the parties to the Existing Contract and the results forwarded to the ISO, the operating instructions

shall be exercised by the Participating TOs, and the outcomes shall be forwarded to the ISO. The determination of whether the operating instructions can be "exercised independently of the ISO by the parties to the Existing Contract" shall be made using the same procedures described in Section 16.2.3.1.1.

16.2.4C To the extent that the operating instructions can not be exercised independently of the ISO and the results forwarded to the ISO (because, for example, they require iteration with the ISO's scheduling process, would unduly interfere with the ISO's real-time management of curtailments or would unduly interfere with the ability of the holder of rights to exercise its rights), the operating instructions will be provided to the ISO for day-to-day implementation. These instructions will be provided by the Responsible PTO to the ISO for implementation unless the parties to the Existing Contracts otherwise agree that the rights holder will do so. For these instructions, the Scheduling Coordinators representing the holders of Existing Rights will submit their Schedules to the ISO for implementation in accordance with the instructions. In this case, the ISO shall act as the scheduling agent for the Participating TOs with regard to Existing Rights.

16.2.4D The ISO shall determine, based on the information provided by the Participating TOs and contract rights holders under Sections 16.2.4B and 16.2.4C, the transmission capacities that (i) must be reserved for firm Existing Rights, (ii) may be allocated for use as ISO transmission service (i.e., new firm uses), (iii) must be reserved by the ISO for conditional firm Existing Rights, and (iv) remain for any non-firm Existing Rights for which a Participating TO has no discretion over whether or not to provide such non-firm service.

16.2.4E The ISO shall coordinate the scheduling of Existing Rights with the scheduling of ISO transmission service, using the ISO's Day-Ahead scheduling rules and protocols. In doing so, the ISO shall subtract, from the capacity that is available for the ISO to schedule in the ISO's Day-Ahead scheduling process, an appropriate amount of transmission capacity reflecting the amount and nature of the Existing Rights.

16.2.4F For those Existing Rights the use of which has not been scheduled by the rights-holders by the start of the ISO's Hour-Ahead scheduling process, the ISO shall coordinate the scheduling of Existing Rights with the scheduling of ISO transmission service, using the ISO's Hour-Ahead scheduling protocols. In doing so, the ISO may, at its own discretion, consider as available for the ISO to schedule in its Hour-Ahead scheduling process, any or all of the transmission capacity associated with Existing Rights the use of which has not been scheduled by the rights-holders in the ISO's Hour-Ahead scheduling process.

16.2.4G The ISO shall recognize that the obligations, terms or conditions of Existing Contracts may not be changed without the voluntary consent of all parties to the contract (unless such contract may be changed pursuant to any applicable dispute resolution provisions in the contract or pursuant to Section 205 or Section 206 of the FPA and the FERC's Rules and Regulations or as otherwise provided by law).

16.2.4H The parties to Existing Contracts shall remain liable for their performance under the Existing Contracts. The ISO shall be liable in accordance with the provisions of this ISO Tariff for any damage or injury caused by its non-compliance with the operating instructions submitted to it pursuant to this Section 16.2.

16.2.4l Unless specified otherwise, in the event that the dispute resolution mechanisms prescribed in an Existing Contract, including all recourses legally available under the contract, can not, in the first instance, result in a resolution of such a dispute, the ISO's ADR Procedure will be used to resolve any disputes between the ISO and the Participating TO regarding any aspects of the implementation of Section 16.1 and 16.2, including the reasonableness of a Participating TO's operating instructions or any other decision rules which the Participating TO may submit to the ISO as part of the operational protocols. The transmission rights-holder(s) under the Existing Contract shall have standing to participate in the ISO ADR Procedure.

16.2.4.1 Allocation of Forecasted Total Transfer Capabilities.

16.2.4.1.1 Prioritization of Transmission Uses.

The following rules are designed to enable the ISO to honor Existing Contracts in accordance with Sections 16.1 and 16.2 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 Section 23, 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 addition, Generation, Inter-Scheduling Coordinator Energy Trade imports or external imports in one Zone must be matched by an equal magnitude of Demand, Inter-Scheduling Coordinator Energy Trade exports or external exports in an adjacent Zone (see Section 16.2.4.1.2 for a summary of allowable linkages). Scheduling and curtailment priorities associated with each category will be defined by Scheduling Coordinators through the use of contract usage templates submitted as part of their Schedules.

(a) Transmission capacity for Schedules will be made available to holders of firm Existing Rights in accordance with this Section and the terms and conditions of their Existing Contracts. In the event that the firm uses of these rights must be curtailed, they will be curtailed on the basis of priority expressed in contract usage templates. So as not to be curtailed before any other scheduled use of Congested Inter-Zonal Interface capacity, the ISO's Congestion Management software will assign high priced Adjustment Bids to the scheduled uses (for example, a difference of $130,000/MWh to $140,000/MWh for Demand or external exports and a difference of -$130,000/MWh to -$140,000/MWh for Generation or external imports). This range will be reserved strictly for use in association with the prioritization of firm Existing Rights to use available Inter-Zonal Interface transmission capacity. These high priced Adjustment Bids are only for the ISO's use, in the context of Inter-Zonal Congestion Management, in recognizing the various levels of priority that may exist among the scheduled uses of firm transmission service. These high priced Adjustment Bids will not affect any other rights under Existing Contracts. To the extent that the MW amount exceeds the MW amount specified in the Existing Contract, the excess scheduled amount will be treated as a new firm use of ISO transmission services as described in (b) below. Note that, in some instances, for a particular Inter-Zonal Interface, there may be multiple Scheduling Coordinators submitting Schedules under several different Existing Contracts on behalf of several Existing Contract rights holders. In these circumstances, and to the extent the rights holders desire to coordinate the prioritization of their firm uses of the Inter-Zonal Interface, their Scheduling Coordinators will make the arrangements among themselves ahead of the ISO's scheduling process. In the absence of a valid contract usage template associated with Existing Contract rights, the ISO will treat the scheduled use of transmission service as a "price-taker" of ISO transmission service subject to Usage Charges.

(b) ISO transmission service (i.e., "new firm uses") will be priced in accordance with the ISO Tariff. Usage Charges associated with the ISO's Congestion Management procedures, as described in Section 27.1.1.5, will be based on Adjustment Bids. In the absence of an Adjustment Bid, the ISO will treat the scheduled "new firm use" of ISO transmission service as a price taker paying the Usage Charge established by the highest valued use of transmission capacity between the relevant Zones.

(c) Transmission capacity will be made available to holders of conditional firm Existing Rights in a manner similar to that done prior to the ISO Operations Date; that is, allocated, as available, based on the agreed priority. The levels of priority will be expressed in the contract usage templates associated with the Schedules. To the extent that the MW amount in a schedule exceeds the MW amount specified in the contract usage template, the excess scheduled amount will be treated as a new firm use of ISO transmission services as described in (b) above. Note that, in some instances, for a particular Inter-Zonal Interface, there may be multiple Scheduling Coordinators submitting Schedules under several different

Existing Contracts on behalf of several Existing Contract rights holders. In these circumstances, and to the extent the rights holders desire to coordinate the prioritization of their conditional firm uses of the Inter-Zonal Interface, their Scheduling Coordinators 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. Non-firm uses of transmission capacity under Existing Contracts will be indicated in Schedules submitted by Scheduling Coordinators as $0.00/MWh Adjustment Bids. Therefore, there will be no contract reference number associated with non-firm Existing Contract rights.

16.2.4.1.2 Allowable Linkages.

As indicated in Section 16.2.4.1.1, Generation, Inter-Scheduling Coordinator Energy Trade imports or external imports in one Zone must be matched by an equal magnitude of Demand, Inter-Scheduling Coordinator Energy Trade exports or external exports in the same Zone or in an adjacent Zone.

16.2.4.2 The Day-Ahead Process.

16.2.4.2.1 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 Scheduling Coordinators on behalf of the rights holders for conformity with the instructions previously provided by the Responsible PTO. Invalid Schedules will be rejected and the ISO will immediately communicate the results of each Scheduling Coordinator's validation to that Scheduling Coordinator via WEnet.

16.2.4.2.2 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).

16.2.4.2.3 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 by subtracting, from the total transfer capability of the Inter-Zonal Interface, the unused portions of capacity applicable to firm Existing Rights. For purposes of Congestion Management, the total transfer capability of the Inter-Zonal Interface 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, two hours ahead of the Settlement Period).

16.2.4.2.4 Allocation of Inter-Zonal Interface Capacities.

In the ISO's Congestion Management analysis of the Day-Ahead Market, for each Inter-Zonal Interface:

(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 Section 16.2.4.1.1) to the extent necessary;

(c) if Congestion still exists after curtailing all lower priority schedules (e.g. requesting non-firm and conditional firm uses of transmission service under Existing Contracts), the remaining transmission capacity (that is not already reserved as firm Existing Rights) is priced based upon Adjustment Bids. To the extent there are insufficient Adjustment 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), pro rata, 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, pro rata, 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 Section 16.2.4.1.1) to the extent necessary.

16.2.4.3 The Hour-Ahead Process.

16.2.4.3.1 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. Invalid schedules will be rejected and the ISO will immediately communicate the results of each Scheduling Coordinator's validation to that Scheduling Coordinator via WEnet.

16.2.4.3.2 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).

16.2.4.3.3 Acceptance of Firm Transmission Schedules.

Before allocating any remaining transmission capacity under the following provisions of this Section 16.2, the ISO will accept Schedules associated with firm Existing Rights (subject to validation under 16.2.4.3.1), allocating transmission capacity for use by these rights holders.

16.2.4.3.4 Reservation of Firm Transmission Capacity.

The ISO will adjust the total transfer capabilities of Inter-Zonal Interfaces with respect to firm Existing Rights as it does in its Day-Ahead process described in this Section 16.2. 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 Section 16.2.4.4.

16.2.4.3.5 Allocation of Inter-Zonal Interface Capacities.

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

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

(b) if all scheduled uses of transmission service do not fit within the total transfer capability, scheduled uses of non-firm Existing Rights will be curtailed, pro rata, 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 Section 16.2.4.1.1) to the extent necessary;

(c) if Congestion still exists after curtailing all lower priority schedules (e.g. representing non-firm and conditional firm uses of transmission service under Existing Contracts), the remaining transmission capacity (the subject of firm Existing Rights) is priced based upon Adjustment Bids. To the extent there are insufficient Adjustment 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), pro rata, 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 Section 16.2.4.1.1) to the extent necessary.

16.2.4.4 The ISO's Real-Time Process.

Consistent with Section 16.2.4.3.4, the ISO will honor those scheduling flexibilities that may be exercised by holders of Existing Rights through their respective Scheduling Coordinators 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 Sections 16.2.4.4.1 and 16.2.4.4.2 will occur during the three hours following the ISO's receipt of Preferred Hour-Ahead Schedules (that is, from two hours ahead of the start of the Settlement Period through the end of such Settlement Period).

16.2.4.4.1 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 Scheduling Coordinator 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 Scheduling Coordinator 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. The ISO will manually adjust the Scheduling Coordinator's schedule to conform with the other Control Area's net schedule in real time, and the notifying Scheduling Coordinator will be responsible for and manage any resulting Energy imbalance. These Imbalance Energy deviations will be priced and accounted to the Scheduling Coordinator representing the holder of Existing Rights in accordance with the Section 11.

16.2.4.4.2 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 Scheduling Coordinator representing the holder of Existing Rights in accordance with the Section 11.

17 [Not Used]

18 [Not Used]

19 DEMAND FORECASTS.

19.1 Scheduling Coordinator and Load-Serving Entity Demand Forecast Responsibilities.

19.1.1 Applicability to Scheduling Coordinators and Load-Serving Entities.

This Section 19.1 shall apply to each Scheduling Coordinator that must submit a Demand Forecast pursuant to Sections 4.5.3.7, 31.1.4.1 or the provisions of Section 40, and each Load-Serving Entity on whose behalf such Demand Forecasts are submitted.

19.1.2 Avoiding Duplication.

Each Scheduling Coordinator submitting a Demand Forecast to the ISO, and each Load-Serving Entity on whose behalf such Demand Forecast is submitted, shall ensure, to the best of their ability, that any Demand Forecast submitted to the ISO is not duplicated in another Scheduling Coordinator's Demand Forecast.

19.1.3 Required Performance.

Each Scheduling Coordinator submitting a Demand Forecast to the ISO, and each Load-Serving Entity on whose behalf such Demand Forecast is submitted, shall take all necessary actions to provide a Demand Forecast that reflects reasonable forecast accuracy standards. Scheduling Coordinators may develop and submit Demand Forecasts earlier than the timeline specified in Section 31.1.4.1 as appropriate to implement WECC-compliant weekend and holiday Demand Forecasts and scheduling practices.

[NOT USED]

[NOT USED]

19.2 ISO Responsibilities.

19.2.1 ISO Advisory Control Area Demand Forecasts.

The ISO will develop and publish on the ISO website and supply to the Scheduling Coordinators advisory Demand Forecasts comprised of Hourly Demand Forecasts for each Congestion Zone for each Settlement Period of the relevant Trading Day. The ISO will publish this information in accordance with the timing requirements set forth in this ISO Tariff.

19.2.2 ISO Annual Reports of Demand and Resources.

On an annual basis in accordance with the requirements of the WECC, the ISO will publish on its website reports that provide estimates of resource availability, peak Demand levels, and reserve capacity during anticipated peak Demand conditions for the ISO Control Area for the summer and any other specified seasons.

20 CONFIDENTIALITY.

20.1 ISO.

The ISO shall maintain the confidentiality of all of the documents, data and information provided to it by any Market Participant that are treated as confidential or commercially sensitive under Section 20.2; provided, however, that the ISO need not keep confidential: (1) information that is explicitly subject to data exchange through WEnet pursuant to Section 6 of this ISO Tariff; (2) information that the ISO or the Market Participant providing the information is required to disclose pursuant to this ISO Tariff, or applicable regulatory requirements (provided that the ISO shall comply with any applicable limits on such disclosure); or (3) information that becomes available to the public on a non-confidential basis (other than as a result of the ISO's breach of this ISO Tariff).

20.2 Confidential Information.

The following information provided to the ISO by Scheduling Coordinators shall be treated by the ISO as confidential:

(a) individual bids for Supplemental Energy;

(b) individual Adjustment Bids for Congestion Management which are not designated by the Scheduling Coordinator as available;

(c) individual bids for Ancillary Services;

(d) transactions between Scheduling Coordinators;

(e) individual Generator Outage programs unless a Generator makes a change to its Generator Outage program which causes Congestion in the short term (i.e. one month or less), in which case, the ISO may publish the identity of that Generator.

(f) Demand Forecast and other hourly data provided by Scheduling Coordinators to the ISO pursuant to Sections 4.5.3.7 and 31.1.4.

The following information provided to the ISO by Scheduling Coordinators or Market Participants for purposes of the Interim Reliability Requirements Program shall be treated by the ISO as confidential:

(a) Annual and monthly Resource Adequacy Plans pursuant to Sections 40.2.1 and 40.2.2, respectively, and Supply Plans pursuant to Section 40.6; however, any Planning Reserve Margin information required by Section 40.4 and any Qualifying Capacity eligibility criteria information required by Section 40.5.1 contained in the Resource Adequacy Plans and/or Supply Plans shall not be treated as confidential.

(b) Demand Forecast and other hourly data provided pursuant to Section 40.3.

(c) Information on existing import contracts, and any trades or sales of allocated import capacity, provided pursuant to Section 40.5.2.2.

(d) Information reported by non-Participating Generators pursuant to Sections 40.6A.3 and 40.7.3.

(e) Information submitted through the dispute or discrepancy resolution process pursuant to Section 40.2.3.

20.3 Other Parties.

No Market Participant shall have the right hereunder to receive from the ISO or to review any documents, data or other information of another Market Participant to the extent such documents, data or information is to be treated as in accordance with Section 20.2; provided, however, a Market Participant may receive

and review any composite documents, data, and other information that may be developed based upon such confidential documents, data, or information, if the composite document does not disclose such confidential data or information relating to an individual Market Participant and provided, however, that the ISO may disclose information as provided for in its bylaws.

20.4 Disclosure.

Notwithstanding anything in this Section 20 to the contrary,

(a) The ISO: (i) shall publish individual bids for Supplemental Energy, individual bids for Ancillary Services, and individual Adjustment Bids, provided that such data are published no sooner than six (6) months after the Trading Day with respect to which the bid or Adjustment Bid was submitted and in a manner that does not reveal the specific resource or the name of the Scheduling Coordinator submitting the bid or Adjustment Bid, but that allows the bidding behavior of individual, unidentified resources and Scheduling Coordinators to be tracked over time; and (ii) may publish data sets analyzed in any public report issued by the ISO or by the Market Surveillance Committee, provided that such data sets shall be published no sooner than six (6) months after the latest Trading Day to which data in the data set apply, and in a manner that does not reveal any specific resource or the name of any Scheduling Coordinator submitting bids or Adjustment Bids included in such data sets.

(b) If the ISO is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 20, the ISO may disclose such information; provided, however, that as soon as the ISO learns of the disclosure requirement and prior to making such disclosure, the ISO shall notify any affected Market Participant of the requirement and the terms thereof. The Market Participant may, at its sole discretion and own cost, direct any challenge to or defense against the disclosure requirement and the ISO shall cooperate with such affected Market Participant to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The ISO shall cooperate with the affected Market Participant to obtain proprietary or confidential treatment of confidential information by the person to whom such information is disclosed prior to any such disclosure.

(c) The ISO may disclose confidential or commercially sensitive information, without notice to an affected Market Participant, in the following circumstances:

(i) If the FERC, or its staff, during the course of an investigation or otherwise, requests information that is confidential or commercially sensitive. In providing the information to FERC or its staff, the ISO shall take action consistent with 18 C.F.R. §§ 1b.20 and 388.112, and request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The ISO shall provide the requested information to the FERC or its staff within the time provided for in the request for information. The ISO shall notify an affected Market Participant within a reasonable time after the ISO is notified by FERC or its staff that a request for disclosure of, or decision to disclose, the confidential or commercially sensitive information has been received, at which time the ISO and the affected Market Participant may respond before such information would be made public; or

(ii) In order to maintain reliable operation of the ISO Control Area, the ISO may share critical operating information, system models, and planning data with other WECC Reliability Coordinators, who have executed the Western Electricity Coordinating Council

Confidentiality Agreement for Electric System Data, or are subject to similar confidentiality requirements; or

(iii) In order to maintain reliable operation of the ISO Control Area, the ISO may share individual Generating Unit Outage information with the operations engineering and/or the outage coordination division(s) of other Control Area operators, Participating TOs, MSS Operators and other transmission system operators engaged in the operation and maintenance of the electric supply system whose system is significantly affected by the Generating Unit and who have executed the Western Electricity Coordinating Council Confidentiality Agreement for Electric System Data.

(d) Information submitted through Resource Adequacy Plans pursuant to Sections 40.2.1 and 40.2.2, Supply Plans pursuant to Section 40.6, and the dispute or discrepancy resolution process pursuant to Section 40.2.3 may be provided to:

(i) the Scheduling Coordinator(s) and/or Market Participant(s) involved in the dispute or discrepancy pursuant to Section 40.2.3, only to the limited extent necessary to identify the disputed transaction and relevant counterparty or counterparties.

(ii) the regulatory entity, whether the CPUC or a Local Regulatory Authority, with jurisdiction over a Load Serving Entity involved, pursuant to Section 40.2.3, in a dispute or discrepancy, or otherwise is identified by the ISO as exhibiting a potential deficiency in demonstrating compliance with Resource Adequacy rules adopted by the CPUC or Local Regulatory Authority, as applicable. The information provided shall be limited to the particular dispute, discrepancy or deficiency.

20.5 Confidentiality.

The ISO shall implement and maintain a system of communications with Scheduling Coordinators that includes the strict use of passwords for access to data to ensure compliance with Section 20. Access within the ISO to such data on ISO's communications systems, including databases and backup files, shall be strictly limited to authorized ISO personnel through the use of passwords and other appropriate means.

21 SCHEDULE VALIDATION TOLERANCES.

21.1 Temporary Simplification of Schedule Validation Tolerances.

Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, a Schedule shall be treated as a Balanced Schedule when aggregate Generation, adjusted for Transmission Losses, is within 20 MW of aggregate Demand, or such lower amount, greater than 1 MW, as may be established from time to time by the ISO. The ISO may establish the Schedule validation tolerance level at any time, between a range from 1 MW to 20 MW, by giving seven days' notice published on the ISO's "Home Page," at http://www.ISO.com or such other Internet address as the ISO may publish from time to time.

21.2 Application.

Notwithstanding any other provision in this Tariff, including the ISO Protocols, the temporary simplification measure specified in this Section 21 shall have effect until discontinued by a Notice of Full-Scale Operations issued by the Chief Executive Officer of the ISO.

21.3 Notices of Full-Scale Operations.

21.3.1 When the Chief Executive Officer of the ISO determines that the ISO is capable of implementing this ISO Tariff, including the ISO Protocols, without modification in accordance with a temporary simplification measure specified in this Section 21, he shall issue a notice ("Notice of Full-Scale Operations") and shall specify the relevant temporary simplification measure and the date on which it will permanently cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.

21.3.2 A Notice of Full-Scale Operations shall be issued when it is posted on the ISO Internet "Home Page," at http://www.caiso.com or such other Internet address as the ISO may publish from time to time.

22 MISCELLANEOUS.

22.1 Audits.

22.1.1 Materials Subject to Audit.

The ISO's financial books, cost statements, accounting records and all documentation pertaining to its operation as a state chartered independent institution which controls the operation of the ISO Controlled Grid to ensure open, non-discriminatory transmission access to all Market Participants and promotes the efficient use and reliable operation of the ISO Controlled Grid in accordance with this ISO Tariff, are subject to audit in the manner prescribed below:

22.1.2 ISO Audit Committee.

The ISO Governing Board shall have overall audit responsibility for the ISO. The ISO Audit Committee shall make recommendations to the ISO Governing Board in relation to the approval, initiation and scheduling of the following audits:

22.1.2.1 Certified Financial Statement Audit.

Each year, an audit by an external independent certified public accounting firm shall be performed. This audit will be conducted in accordance with generally accepted auditing standards to verify that the ISO's financial statements are in compliance with generally accepted accounting principles and fairly present, in all material respects, the financial position, results of operation and cash flows for the audit period. The audit report will be addressed to the ISO Governing Board, copies will be provided to the ISO Audit Committee, and, upon request, to Market Participants.

22.1.2.2 Operations Audit.

Each year, an independent accounting firm shall review the ISO management's compliance with its operations policies and procedures. The ISO Audit Committee will appoint an independent firm to do this audit. This audit may also include material issues raised by Market Participants and approved by the ISO Audit Committee for inclusion in the audit scope. The audit report will be addressed to the ISO Governing Board, copies provided to the ISO Audit Committee, and upon request, to Market Participants.

22.1.2.3 Code of Conduct Audits.

On a periodic basis, but not less than once a year, an independent accounting firm shall conduct a management review of governors, officers, employees, substantially full-time consultants, or contractors of the ISO for compliance with the ISO Code of Conduct to ensure adherence to the highest standards of lawful and ethical conduct in their activities. The audit report shall be addressed to the ISO Audit Committee with copies provided to the ISO Governing Board and, upon request, to Market Participants.

22.1.2.4 Interim Audits.

At such other intervals agreed upon by a majority of the ISO Audit Committee members, audits may be undertaken for specific issues and concerns of Market Participants that the ISO Audit Committee believes, at its sole discretion, to be of significant and critical magnitude to the ISO. Such audits will be conducted by an independent accounting firm. The costs of such an audit will be borne by the requesting Market Participant(s), unless the ISO Audit Committee determines otherwise. Interim audits will be conducted during normal business hours, after reasonable notice has been given to the ISO, and in accordance with the guidelines to be established by the ISO Audit Committee.

22.1.3 Audit Results.

Exceptions identified as a result of an audit will be reviewed with the ISO Audit Committee. The results of the audits and actions to be taken by the ISO as a result of the audit shall be mailed to Market Participants upon request.

22.1.4 Availability of Records.

The ISO will provide full and complete access to all financial books, cost statements, accounting records, and all documentation pertaining to the requirements of the specific audits being performed. Records relating to audits will be retained until the records retention requirements of the ISO are satisfied or until the audit issues are fully resolved, whichever is the later. The right of access to records does not require the creation of new records, reports, studies, or evaluations not already available.

22.1.5 Confidentiality of Information.

All proprietary information obtained through any audits will remain strictly confidential. All auditors shall sign a confidentiality agreement prior to being accepted as auditors by the ISO Audit Committee.

22.1.6 Payments.

Any payments agreed to between Market Participants and the ISO as a result of an audit, or directed by FERC, or disclosed by the ISO in reviews of its own books and records shall include interest computed at the rate calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R § 35.19(a)(2)(iii) (as amended from time to time) from the due date to the date such adjustments are due.

22.2 Assignment.

Obligations and liabilities under this ISO Tariff and any Scheduling Coordinator Agreement or other agreements giving contractual effect to this ISO Tariff shall be binding on the successors and assigns of the parties to such agreements. No assignment of any Scheduling Coordinator Agreement or other agreements giving contractual effect to this ISO Tariff shall relieve the original party from its obligations or liabilities to the ISO under this ISO Tariff or any such agreement arising or accruing due prior to the date of assignment.

22.3 Term and Termination.

22.3.1 This ISO Tariff, shall become effective on the date it is permitted to become effective by the FERC.

22.3.2 This ISO Tariff shall terminate upon approval of termination by the ISO Governing Board in accordance with the bylaws of the ISO and receipt of any necessary regulatory approval from FERC.

22.4 Notice.

22.4.1 Effectiveness.

Any notice, demand, or request in accordance with this ISO Tariff, unless otherwise provided in this ISO Tariff or in any ISO Protocol, shall be in writing and shall be deemed properly served, given, or made: (a) upon delivery if delivered in person, (b) five (5) days after deposit in the mail if sent by first class United States mail, postage prepaid, (c) upon receipt of confirmation by return facsimile if sent by facsimile, or (d) upon delivery if delivered by prepaid commercial courier service.

22.4.2 Addresses.

Notices to the ISO shall be sent to such address as shall be notified by the ISO to Market Participants from time to time. Notices issued by the ISO to any Scheduling Coordinator shall be delivered to the address of the Scheduling Coordinator included in the Scheduling Coordinator Application Form. Notices to any Market Participant other than a Scheduling Coordinator shall be delivered by the ISO to the address given to it by the Market Participant. The ISO and any Market Participant may at any time change their address for notice by notifying the other party in writing.

22.4.3 Notice of Changes in Operating Rules and Protocols.

The ISO shall give all Market Participants notice of at least thirty (30) days of any changes or proposed changes in its operating rules, procedures and protocols, unless: (1) a different notice period is specified by state or Federal law or (2) the change is reasonably required to address an emergency affecting the ISO Controlled Grid or its operations, in which case the ISO shall give Market Participants as much notice as is reasonably practicable. Any notices issued under this provision shall be delivered in accordance with the procedures set out in Section 22.4 of this ISO Tariff and, in the case of the ISO Protocols, Section 22.11 of this ISO Tariff.

22.5 Waiver.

Any waiver at any time by the ISO or any Market Participant of its rights with respect to any default under this ISO Tariff, or with respect to any other matter arising in connection with this ISO Tariff, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this ISO Tariff. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not constitute or be deemed a waiver.

22.6 Staffing and Training To Meet Obligations.

The ISO shall engage sufficient staff to perform its obligations under this ISO Tariff in a satisfactory manner consistent with Good Utility Practice. The ISO shall make its own arrangements for the engagement of all staff and labor necessary to perform its obligations hereunder and for their payment. The ISO shall employ (or cause to be employed) only persons who are appropriately qualified, skilled and experienced in their respective trades or occupations. ISO employees and contractors shall abide by the ISO Code of Conduct for employees contained in the ISO bylaws and approved by FERC.

22.7 Accounts and Reports.

The ISO shall notify Market Participants of any significant change in the accounting treatment or methodology of any costs or any change in the accounting procedures, which is expected to result in a significant cost increase to any Market Participant. Such notice shall be given at the earliest possible time, but no later than, sixty (60) days before implementation of such change**.**

22.8 Applicable Law and Forum.

This ISO Tariff shall be governed by and construed in accordance with the laws of the State of California, except its conflict of laws provisions. Market Participants irrevocably consent that any legal action or proceeding arising under or relating to this ISO Tariff to which the ISO ADR Procedures do not apply, shall be brought in any court of the State of California or any federal court of the United States of America located in the State of California. Market Participants irrevocably waive any objection that they may have now or in the future to said courts in the State of California as the proper and exclusive forum for any legal action or proceeding arising under or related to this ISO Tariff.

22.9 Consistency with Federal Laws and Regulations.

(a) Nothing in the Tariff shall compel any person or federal entity to: (1) violate federal statutes or regulations; or (2) in the case of a federal agency, to exceed its statutory authority, as defined by any applicable federal statutes, regulations, or orders lawfully promulgated thereunder. If any provision of this Tariff is inconsistent with any obligation imposed on any person or federal entity by federal law or regulation to that extent, it shall be inapplicable to that person or federal entity. No person or federal entity shall incur any liability by failing to comply with a Tariff provision that is inapplicable to it by reason of being inconsistent with any federal statutes, regulations, or orders lawfully promulgated thereunder; provided, however, that such person or federal entity shall use its best efforts to comply with the Tariff to the extent that applicable federal laws, regulations, and orders lawfully promulgated thereunder permit it to do so.

(b) If any provision of this Tariff requiring any person or federal entity to give an indemnity or impose a sanction on any person is unenforceable against a federal entity, the ISO shall submit to the Secretary of Energy or other appropriate Departmental Secretary a report of any circumstances that would, but for this provision, have rendered a federal entity liable to indemnify any person or incur a sanction and may request the Secretary of Energy or other appropriate Departmental Secretary to take such steps as are necessary to give effect to any provisions of this Tariff that are not enforceable against the federal entity.

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

22.10 ISO Grid Operations Committee; Changes To ISO Protocols.

22.10.1 ISO Grid Operations Committee.

The ISO Grid Operations Committee shall coordinate activities relating to the ISO Controlled Grid and shall consider suggestions for changes to the ISO Protocols in accordance with the procedures set out in Article IV, Section 4 of the ISO's bylaws.

22.11 ISO Protocol Amendment Process.

The ISO Governing Board shall establish an ISO Protocol amendment process in order to ensure that all affected parties have an opportunity to participate. Under that process, the ISO shall file for acceptance at the FERC any amendment to an ISO Protocol that is on file with the FERC.

22.13 Scheduling Responsibilities and Obligations.

Nothing in this ISO Tariff is intended to permit or require the violation of Federal or California law concerning hydro-generation and Dispatch, including but not limited to fish release requirements, minimum and maximum dam reservoir levels for flood control purposes, and in-stream flow levels. In carrying out its functions, the ISO will comply with and will have the necessary authority to give instructions to Participating TOs and Market Participants to enable it to comply with requirements of environmental legislation and environmental agencies having authority over the ISO in relation to Environmental Dispatch and will expect that submitted Schedules will support compliance with the requirements of environmental legislation and environmental agencies having authority over Generators in relation to Environmental Dispatch. In contracting for Ancillary Services and Imbalance Energy the ISO will not act as principal but as agent for and on behalf of the relevant Scheduling Coordinators.

ARTICLE II – TRANSMISSION SERVICE

23 CATEGORIES OF TRANSMISSION CAPACITY.

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 Inter-Zonal Interface, the ISO will allocate the forecasted total transfer capability of the Interface to four categories.

This allocation will represent the ISO's best estimates at the time, and is not intended to affect any rights provided under Existing Contracts, except as provided in Section 16.2.4.3. The ISO's forecast of total transfer capability for each Inter-Zonal 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 WEnet by the ISO in accordance with Appendix Y. In accordance with Section 16.2.4D of the ISO Tariff, the four categories are as follows:

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

(b) transmission capacity that may be allocated for use as ISO transmission service (i.e., "new firm uses");

(c) transmission capacity that may be allocated by the ISO for conditional firm Existing Rights; and

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

24 TRANSMISSION EXPANSION.

A Participating TO shall be obligated to construct all transmission additions and upgrades that are determined to be needed in accordance with the requirements of this Section 24 and which: (1) are additions or upgrades to transmission facilities that are located within its PTO Service Territory, unless it does not own the facility being upgraded or added and neither terminus of such facility is located within its PTO Service Territory; or (2) are additions to existing transmission facilities or upgrades to existing transmission facilities that it owns, that are part of the ISO Controlled Grid, and that are located outside of its PTO Service Territory, unless the joint-ownership arrangement, if any, does not permit. A Participating TO's obligation to construct such transmission additions and upgrades shall be subject to: (1) its ability, after making a good faith effort, to obtain all necessary approvals and property rights under applicable federal, state, and local laws and (2) the presence of a cost recovery mechanism with cost responsibility assigned in accordance with Section 24.7. The obligations of the Participating TO to construct such transmission additions or upgrades will not alter the rights of any entity to construct and expand transmission facilities as those rights would exist in the absence of the TO's obligations under this ISO

Tariff or as those rights may be conferred by the ISO or may arise or exist pursuant to this ISO Tariff.

24.1 Determination of Need.

A Participating TO or any other Market Participant may propose a transmission system addition or upgrade. The ISO will determine that a transmission addition or upgrade is needed where it will promote economic efficiency or maintain System Reliability as set forth below.

24.1.1 Economically Driven Projects.

The Participating TO and Market Participants shall provide the necessary assistance and information to the ISO, as part of the coordinated planning process, to enable the ISO to determine that a project is needed to promote economic efficiency, including, at the ISO's discretion, studies comporting with ISO guidelines that demonstrate whether the project will promote economic efficiency or the information the ISO requires to carry out its own studies for economically driven projects. The ISO shall treat market sensitive information provided to the ISO in accordance with this Section by Participating TOs, Project Sponsors and applicable Market Participants confidentially in accordance with Section 20 provided that such information is clearly marked "Confidential" at the time it is provided to the ISO. The determination that a transmission addition or upgrade is needed to promote economic efficiency shall be made in any of the following ways:

24.1.1.1 If the Participating TO or any party questions the economic need for the project (except where the Project Sponsor commits to pay the full cost of construction) the proposal will be submitted to the ISO ADR Procedures for resolution.

24.1.1.2 Where a Project Sponsor other than the Participating TO commits to pay the full cost of construction of a transmission addition or upgrade and its operation, and demonstrates to the ISO financial capability to pay those costs, such commitment and demonstration shall be sufficient to demonstrate need to the ISO. To ensure that the Project Sponsor is financially able to pay the costs of the project to be constructed by the Participating TO, the Participating TO may require (1) a demonstration of creditworthiness (e.g. an appropriate credit rating), or (2) sufficient security in the form of an unconditional and irrevocable letter of credit or other similar security sufficient to meet its responsibilities and obligations for the full costs of the transmission addition or upgrade.

24.1.1.3 Where a Project Sponsor asserts that a transmission addition or upgrade is economically beneficial, but that Project Sponsor is unwilling to commit to pay the full cost of the addition or upgrade; where (1) the proposed transmission addition or upgrade was submitted to the Participating TO but was not included in the transmission expansion plan of that Participating TO in accordance with Section 24.2 or (2) the operation date of the planned expansion is not acceptable to the ISO or the Project Sponsor or (3) the Participating TO unreasonably delays implementing or subsequently decides not to proceed with the project, the Project Sponsor may submit its proposal to the ISO ADR Procedure for determination of need. A determination of need shall be made as follows:

24.1.1.3.1 The Project Sponsor shall include in its proposal: (1) a showing that the economic benefits of the proposed transmission addition or upgrade are expected to exceed its costs (giving consideration to any reasonable alternatives to the construction of transmission additions or upgrades) using an economic analysis that comports with ISO guidelines, and (2) a statement of the proposed pricing methodology for the transmission upgrades or additions that the Project Sponsor elects in accordance with Section 24.7 of the ISO Tariff.

24.1.1.3.2 If neither any Market Participant nor the ISO disputes the Project Sponsor's showing, then the proposal is determined to be needed.

24.1.1.3.3 If any Market Participant or the ISO disputes the Project Sponsor's showing, the disputing Market Participant, the ISO, or the Project Sponsor may submit to resolution through the ISO ADR Procedure the issue of whether the transmission addition or upgrade is needed on the ground that its economic benefits exceed its costs. If a Market Participant fails to raise through the ISO ADR Procedure a dispute as to whether a proposed transmission addition or upgrade is needed, then the Market Participant shall be deemed to have waived its right to raise such dispute at a later date. The determination under the ISO ADR Procedure as to whether the transmission addition or upgrade is needed, including any determination by FERC or on appeal of a FERC determination in accordance with that process, shall be final.

24.1.2 Reliability Driven Projects.

The ISO in coordination with the Participating TO, will identify the need for any transmission additions or upgrades required to ensure System Reliability consistent with all Applicable Reliability Criteria. In making this determination, the ISO, in coordination with the Participating TO and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, demand-side management, remedial action schemes, constrained-on Generation, interruptible Loads or reactive support. The Participating TO, in cooperation with the ISO, shall perform the necessary studies to determine the facilities needed to meet all Applicable Reliability Criteria. The Participating TO shall provide the ISO and other Market Participants with all information relating to a proposed transmission addition or upgrade that they may reasonably request (other than information available to them through the WECC or any other applicable regional organization) and shall, through the WECC or any other applicable regional organization coordinated planning processes, develop the scope of and assumptions for such studies that are acceptable to the ISO and those other Market Participants. The ISO shall be free to propose any transmission upgrades or additions it deems necessary to ensure System Reliability consistent with Applicable Reliability Criteria, and, subject to appropriate appeals, the Participating TO shall be obligated to construct such lines. After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs and MSSs, will work to develop a consistent set of Reliability Criteria for the ISO Controlled Grid which the Participating TOs will use in their transmission planning and expansion studies or decisions.

24.2 Transmission Planning and Coordination.

The ISO shall actively participate with each Participating TO and the other Market Participants in the ISO Controlled Grid planning process in accordance with the terms of this ISO Tariff and the Transmission Control Agreement.

24.2.1 Each Participating TO with a PTO Service Territory shall develop annually a transmission expansion plan covering the next five years plus a ten-year case for the Loads that are geographically embedded within its PTO Service Territory and are within the ISO Control Area, even if such Loads are served by another Participating TO. Such Participating TO shall coordinate with the ISO and other Market Participants in the development of such plan. The Participating TO shall be responsible for ensuring that its transmission expansion plan meets all Applicable Reliability Criteria.

24.2.2 The ISO shall review the Participating TOs' transmission expansion plans for the PTO Service Territory, whether or not such plans are subject to Section 24.2.1, to ensure that each Participating TO's expansion plans meet the Applicable Reliability Criteria. The Participating TO will provide the necessary assistance and information as part of the coordinated planning process to the ISO to enable it to carry out its own studies for these purposes. If the ISO finds that the Participating TO's plan or projects do not meet the Applicable Reliability Criteria, the ISO will provide comments and the Participating TO will reassess its plans, as appropriate. The ISO may also propose new projects or suggest project changes (*e.g.*, timing, project size) for consideration by the Participating TO. Changes or additions made by the ISO and accepted by the TO will be included in the Participating TO's expansion plan. Changes or additions not accepted in the coordinated planning process will be resolved through the ISO ADR Procedure.

24.2.3 The Participating TO will act as a Project Sponsor for Participating TO proposed economic or reliability projects that are included in its expansion plan. The Participating TO shall provide to the ISO any information that the ISO requires to enable the ISO to comply with WECC and any other applicable regional coordination requirements pursuant to Section 24.6.

24.2.4 The ISO will be a member of the WECC and other applicable regional organizations and participate in WECC's operation and planning committees, and in other applicable regional coordinated planning processes. Neither the ISO nor any Participating TO nor any Market Participant shall take any position before the WECC or a regional organization that is inconsistent with a binding decision reached through the ISO ADR Procedure.

24.3 Studies to Determine Facilities to be Constructed.

Where a Participating TO is obligated to construct or expand facilities in accordance with this ISO Tariff or where the ISO or any Market Participant requests that a Facility Study be carried out, the Participating TO (in coordination with the ISO or the relevant Market Participants as the case may require), shall perform the necessary study or studies to determine the appropriate facilities to be constructed in accordance with the terms set forth in the TO Tariff. The scope of and assumptions for any studies requested by a Project Sponsor of a transmission addition or upgrade on economic grounds must be acceptable to the Project Sponsors and the ISO. Any dispute relating to a Facility Study Agreement (including any dispute over the scope of the study or its assumptions) shall be resolved through the ISO ADR Procedures.

24.4 Operational Review.

The ISO will perform an operational review of all facilities that are to be connected to, or made part of, the ISO Controlled Grid to ensure that the facilities being proposed provide for acceptable operating flexibility and meet all its requirements for proper integration with the ISO Controlled Grid. If the ISO finds that such facilities do not provide for acceptable operating flexibility or do not adequately integrate with the ISO Controlled Grid, the Participating TO will reassess its determination of the facilities required to be constructed.

24.5 State and Local Approval and Property Rights.

24.5.1 The Participating TO shall be obligated to make a good faith effort to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of transmission additions or upgrades required to be constructed in accordance with this ISO Tariff. This obligation includes the Participating TO's use of eminent domain authority, where provided by state law.

24.5.2 If the Participating TO cannot secure any such necessary approvals or property rights and consequently is unable to construct a transmission addition or upgrade, it shall promptly notify the ISO and the Project Sponsor and shall comply with its obligations under the TO Tariff to convene a technical meeting to evaluate alternative proposals. The ISO shall take such action as it reasonably considers appropriate, in coordination with the Participating TO, the Project Sponsor (if any) and other affected Market Participants, to facilitate the development and evaluation of alternative proposals including, where possible, conferring on a third party the right to build the transmission addition or upgrade.

24.5.3 Where it is possible for a third party to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of transmission additions or upgrades required to be constructed in accordance with this ISO Tariff (including the use of eminent domain authority, where provided by state law) the ISO may confer on a third party the right to build the transmission addition or upgrade which shall enter into the Transmission Control Agreement in relation to such transmission addition or upgrade.

24.6 WECC and Regional Coordination.

The Project Sponsor will have responsibility for completing any applicable WECC requirements and other applicable regional coordination and rating study requirements to ensure that a proposed transmission addition or upgrade meets regional planning requirements. The Project Sponsor may request the Participating TO to perform this coordination on behalf of the Project Sponsor at the Project Sponsor's expense.

24.7 Cost Responsibility for Transmission Additions or Upgrades.

Cost responsibility for transmission additions or upgrades constructed pursuant to this Section 24 (including the responsibility for any costs incurred under Section 24.6) shall be determined as follows:

24.7.1 Where a Project Sponsor commits to pay the full cost of a transmission addition or upgrade as set forth in Section 24.1.1.2, the full costs shall be borne by the Project Sponsor.

24.7.2 Where the need for a transmission addition or upgrade is determined by the ISO or as a result of the ISO ADR Procedure as set forth in Section 24.1.1.3, the cost of the transmission addition or upgrade shall be borne by the Participating TO that will be the owner of the transmission addition or upgrade and shall be reflected in its Transmission Revenue Requirement.

24.7.3 Provided that the ISO has Operational Control of the transmission upgrade or addition, a Project Sponsor that does not recover the investment cost under a FERC-approved rate through the Access Charge or a reimbursement or direct payment from a Participating TO shall be entitled to receive:

(a) its share, as determined in subsection (d) below, of the Wheeling revenues calculated in accordance with Section 26.1.4.3 that are attributable to the transmission addition or upgrade, which shall be determined by using the capacity increase, if any, of a Scheduling Point, to the extent such increase results from the addition or upgrade, as the rating increase for purposes of subsection (d) below;

(b) its share, as determined in subsection (d) below, of the proceeds of the FTR auction for FTRs defined on the Inter-Zonal Interface of which the transmission addition or upgrade forms a part as set forth in Section 36.5.3, provided that the Project Sponsor does not receive FTRs from the ISO in accordance with Section 36.4.3 of the ISO Tariff; and

(c) its share, as determined in subsection (d) below, of the Congestion revenues provided as calculated pursuant to Section 27.1.2.1.6 on the Inter-Zonal Interface of which the transmission addition or upgrade forms a part.

(d) The Project Sponsor's share of Wheeling, Congestion and FTR auction revenues for the upgraded transmission facility shall be the number that is determined by dividing the number that is determined by subtracting the rating of the transmission facility before the upgrade or addition from the new rating for the upgraded or additional transmission facility by the new rating for the upgraded or additional transmission facility. The Participating TO's share of Wheeling, Congestion and FTR auction revenues for the upgraded or additional transmission facility shall be the number that is determined by subtracting the Project Sponsor's share from one hundred percent (100%). Such allocated shares shall become effective on the date the new rating takes effect. The full amount of capacity added to the system will be as determined through the regional reliability council process of the Western Electricity Coordinating Council or its successor.

24.7.4 Once a New Participating TO has executed the Transmission Control Agreement and it has become effective, the cost for New High Voltage Facilities for all Participating TOs shall be included in the ISO Grid-wide component of the High Voltage Access Charge in accordance with Schedule 3 of Appendix F, unless and with respect to Western Path 15 only, cost recovery is provided in Section 24.7.3. The Participating TO who is supporting the cost of the New High Voltage Facility shall include such costs in its High Voltage Transmission Revenue Requirement, regardless of which TAC Area the facility is geographically located.

24.8 Ownership of and Charges for Expansion Facilities.

24.8.1 All transmission additions and upgrades constructed in accordance with this Section 24 shall form part of the ISO Controlled Grid and shall be operated and maintained by a Participating TO in accordance with the Transmission Control Agreement.

24.8.2 Each Participating TO that owns or operates transmission additions and upgrades constructed in accordance with this Section 24 shall provide access to them and charge for their use in accordance with this ISO Tariff and its TO Tariff.

24.9 Expansion by "Local Furnishing" Participating TOs

Notwithstanding any other provision of this ISO Tariff, a Local Furnishing Participating TO shall not be obligated to construct or expand facilities, (including interconnection facilities as described in Section 8 of the TO Tariff) unless the ISO or Project Sponsor has tendered an application under FPA Section 211 that requests FERC to issue an order directing the Local Furnishing TO to construct such facilities pursuant to Section 24 of the ISO Tariff. The Local Furnishing TO shall, within 10 days of receiving a copy of the Section 211 application, waive its right to a request for service under FPA Section 213(a) and to the issuance of a proposed order under FPA Section 212(c). Upon receipt of a final order from FERC that is no longer subject to rehearing or appeal, such Local Furnishing TO shall construct such facilities in accordance with this Section 24.

25 INTERCONNECTION OF GENERATING UNITS AND GENERATING FACILITIES TO THE ISO CONTROLLED GRID.

25.1 Applicability.

This Section 25 and the Standard Large Generator Interconnection Procedures (LGIP) or ISO Tariff Appendix W, as applicable, shall apply to:

(a) each new Generating Unit that seeks to interconnect to the ISO Controlled Grid;

(b) each existing Generating Unit connected to the ISO Controlled Grid that will be modified with a resulting increase in the total capability of the power plant;

(c) each existing Generating Unit connected to the ISO Controlled Grid that will be modified without increasing the total capability of the power plant but has changed the electrical characteristics of the power plant such that its re-energization may violate Applicable Reliability Criteria; and

(d) each existing qualifying facility Generating Unit connected to the ISO Controlled Grid whose total Generation was previously sold to a Participating TO or on-site customer but whose Generation, or any portion thereof, will now be sold in the wholesale market, subject to Section 25.1.2 below.

25.1.1 The owner of a Generating Unit described in Section 25.1 (a), (b), or (c), or its designee, shall be an Interconnection Customer required to submit an Interconnection Request and comply with the LGIP or ISO Tariff Appendix W, as applicable.

25.1.2 If the owner of a qualifying facility described in Section 25.1(d), or its designee, represents that the total capability and electrical characteristics of the qualifying facility will be substantially unchanged, then that entity must submit an affidavit to the ISO and the applicable Participating TO representing that the total capability and electrical characteristics of the qualifying facility will remain substantially unchanged. If there is any change to the total capability and electrical characteristics of the qualifying facility, however, the affidavit shall include supporting information describing any such changes. The ISO and the applicable Participating TO shall have the right to verify whether or not the total capability or electrical characteristics of the qualifying facility have changed or will change.

25.1.2.1 If the ISO and the applicable Participating TO confirm that the electrical characteristics are substantially unchanged, then that request will not be placed into the interconnection queue. However, the owner of the qualifying facility, or its designee, will be required to execute either a Standard Large Generator Interconnection Agreement in accordance with Section 11 of the LGIP or an interconnection agreement in accordance with ISO Tariff Appendix W, as applicable.

25.1.2.2 If the ISO and the applicable Participating TO cannot confirm that the total capability and electrical characteristics are and will be substantially unchanged, then the owner of the qualifying facility, or its designee, shall be an Interconnection Customer required to submit an Interconnection Request and comply with either the LGIP or ISO Tariff Appendix W, as applicable.

25.2 Interconnections to the Distribution System.

Any proposed interconnection by the owner of a planned Generating Unit, or its designee, to connect that Generating Unit to a Distribution System of a Participating TO will be processed, as applicable, pursuant to the Wholesale Distribution Access Tariff or CPUC Rule 21, or other Local Regulatory Authority requirements, if applicable, of the Participating TO; provided, however, that the owner of the planned Generating Unit, or its designee, shall be required to mitigate any adverse impact on reliability of the ISO Controlled Grid consistent with the Standard Large Generator Interconnection Procedures. In addition, each Participating TO will provide to the ISO a copy of the system impact study used to determine the impact of a planned Generating Unit on the Distribution System and the ISO Controlled Grid pursuant to a request to interconnect under the applicable Wholesale Distribution Access Tariff or CPUC Rule 21, or other Local Regulatory Authority requirements, if applicable.

25.3 Maintenance of Encumbrances.

No new Generating Unit shall adversely affect the ability of the applicable Participating TO to honor its Encumbrances existing as of the time an Interconnection Customer submits its Interconnection Request to the ISO. The applicable Participating TO, in consultation with the ISO, shall identify any such adverse effect on its Encumbrances in the Interconnection System Impact Study performed under Section 7 of the LGIP or under Section 5.1 of ISO Tariff Appendix W, as applicable. To the extent the applicable Participating TO determines that the connection of the new Generating Unit will have an adverse effect on Encumbrances, the Interconnection Customer shall mitigate such adverse effect.

26 TRANSMISSION RATES AND CHARGES.

26.1 Access Charges.

All Market Participants withdrawing Energy from the ISO Controlled Grid shall pay Access Charges in accordance with this Section 26.1 and Appendix F, Schedule 3, except as provided in SPP 4.1. Prior to the transition date determined under Section 4 of Schedule 3 to Appendix F, the Access Charge for each Participating TO shall be determined in accordance with the principles set forth in this Section 26.1 and in Section 5 of the TO Tariff. The Access Charge shall comprise two components, which together shall be designed to recover each Participating TO's Transmission Revenue Requirement. The first component shall be the annual authorized revenue requirement associated with the transmission facilities and Entitlements turned over to the Operational Control of the ISO by a Participating TO approved by FERC. The second component shall be based on the Transmission Revenue Balancing Account (TRBA), which shall be designed to flow through to the Participating TO's Transmission Revenue Credits calculated in accordance with Section 5 of the TO Tariff and other credits identified in Sections 6 and 8 of Schedule 3 in Appendix F of the ISO Tariff.

Commencing on the transition date determined under Section 4 of Schedule 3 to Appendix F, the Access Charges shall be paid by any UDC or MSS Operator that is serving Gross Load in a PTO Service Territory, and shall consist, where applicable, of a High Voltage Access Charge, a Transition Charge and a Low Voltage Access Charge. High Voltage Access Charges and Low Voltage Access Charges shall each comprise two components, which together shall be designed to recover each Participating TO's High Voltage Transmission Revenue Requirement and Low Voltage Transmission Revenue Requirement, as applicable. The first component shall be based on the annual authorized Transmission Revenue Requirement associated with the high voltage or low voltage, as applicable, transmission facilities and Entitlements turned over to the ISO Operational Control by a Participating TO. The second component shall be the Transmission Revenue Balancing Account (TRBA), which shall be designed to flow through the Participating TO's Transmission Revenue Credits associated with the high voltage or low voltage, as applicable, transmission facilities and Entitlements and calculated in accordance with Section 5 of the TO Tariff and other credits identified in Sections 6, 8, and 13 of Schedule 3 of Appendix F of the ISO Tariff. Each Participating TO shall provide in its TO Tariff filing with FERC an appendix to such filing that states the Participating TO's High Voltage Transmission Revenue Requirement, its Low Voltage Transmission Revenue Requirement (if applicable) and its Gross Load used in developing the rate. The allocation of each Participating TO's Transmission Revenue Requirement between the High Voltage Transmission Revenue Requirement and the Low Voltage Transmission Revenue Requirement shall be undertaken in accordance with Section 11 of Schedule 3 of Appendix F. To the extent necessary, each Participating TO shall make conforming changes to its TO Tariff.

The applicable High Voltage Access Charge and the Transition Charge shall be paid to the ISO by each UDC and MSS Operator based on its Gross Load connected to a High Voltage Transmission Facility in a PTO Service Territory, either directly or through intervening distribution facilities, but not through a Low Voltage Transmission Facility. The applicable High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge for the applicable Participating TO shall be paid by each UDC and MSS Operator based on its Gross Load in the PTO Service Territory. The applicable High Voltage Access Charge and Transition Charge shall be assessed by the ISO as a charge for transmission service under this ISO Tariff, shall be determined in accordance with Schedule 3 of Appendix F, and shall include all applicable components of the High Voltage Access Charge and Transition Charge set forth therein.

The Low Voltage Access Charge for each Participating TO is set forth in that Participating TO's TO Tariff. Each Participating TO shall charge for and collect the Low Voltage Access Charge, as provided in its TO Tariff, except that the ISO shall charge for and collect the Low Voltage Access Charge of each Non-Load-Serving Participating TO that qualifies under this Section 26.1 and Appendix F, Schedule 3, Section 13, unless otherwise agreed by the affected Participating TOs. If a Participating TO that is also a UDC, MSS Operator, or Scheduling Coordinator serving End-Use Customers is using the Low Voltage Transmission Facilities of another Participating TO, such Participating TO shall also be assessed the Low Voltage Access Charge of the other Participating TO by such other Participating TO, or by the ISO pursuant to Section 13 of Schedule 3 of Appendix F. The ISO shall provide to the applicable Participating TO a statement of the amount of Energy delivered to each UDC and MSS Operator serving Gross Load that utilizes the Low Voltage Transmission Facilities of that Participating TO on a monthly basis. If a UDC or MSS Operator that is serving Gross Load in a PTO Service Territory has Existing Rights to use another Participating TO's Low Voltage Transmission Facilities, such entity shall not be charged the Low Voltage Access Charge for delivery of Energy to Gross Load for deliveries using the Existing Rights. Each Participating TO shall recover Standby Transmission Revenues directly from the Standby Service Customers of that Participating TO through its applicable retail rates.

Where a Non-Load-Serving Participating TO has Low Voltage Transmission Facilities, the ISO shall assess the Low Voltage Access Charge for each project of that Non-Load-Serving Participating TO to the UDC or MSS Operator of each Participating TO that is directly connected to one or more Low Voltage Transmission Facilities of that project, unless otherwise agreed by the affected Participating TOs. The Non-Load-Serving Participating TO shall calculate separately its Low Voltage Transmission Revenue Requirement for each individual transmission project that includes one or more Low Voltage Transmission Facilities. If the Non-Load-Serving Participating TO's Low Voltage Transmission Facilities projects are directly connected to the facilities of the same Participating TO(s), the Low Voltage Access Charge shall be calculated for the group of Low Voltage Transmission Facilities. A separate Low Voltage Access Charge shall apply based on the Low Voltage Transmission Revenue Requirement for the relevant project or projects of such Non-Load-Serving Participating TO divided by the Gross Load of all UDCs or MSS Operators of a Participating TO that are directly connected to the relevant Low Voltage Transmission Facility or group of facilities.

A Non-Load-Serving Participating TO must include any over- or under-recovery of its annual Low Voltage Transmission Revenue Requirement for the relevant project or group of projects in its low voltage TRBA adjustment for its Low Voltage Access Charge for the relevant project or group of projects pursuant to Section 13.1 of Schedule 3 of Appendix F.

A Participating TO that is a UDC or MSS Operator to whom the Low Voltage Access Charge of a Non-Load-Serving Participating TO is assessed shall include these billed Low Voltage Access Charge amounts in its low voltage TRBA adjustment for its Low Voltage Access Charge, together with all other applicable low voltage TRBA adjustments.

26.1.1 Publicly Owned Electric Utilities Access Charge.

Local Publicly Owned Electric Utilities whose transmission facilities are under ISO Operational Control shall file with the FERC their proposed High Voltage Transmission Revenue Requirements, and any proposed changes thereto, under procedures determined by the FERC to be applicable to such filings and shall give notice to the ISO and to all Scheduling Coordinators of any such filing. A prospective New

Participating TO that is a Local Publicly Owned Electric Utility shall submit its first proposed High Voltage Transmission Revenue Requirement to the FERC and the ISO at the time the Local Publicly Owned Electric Utility submits its application to become a New Participating TO in accordance with the Transmission Control Agreement. Federal power marketing agencies whose transmission facilities are under ISO Operational Control shall develop their High Voltage Transmission Revenue Requirement pursuant to applicable federal laws and regulations.

The procedures for public participation in a federal power marketing agency's ratemaking process are posted on the federal power marketing agency's website. Each federal power marketing agency shall also post on its website the Federal Register Notices and FERC orders for rate making processes that impact the federal power marketing agency's High Voltage Transmission Revenue Requirement. At the time the federal power marketing agency submits its application to become a New Participating TO in accordance with the Transmission Control Agreement, it shall submit its first proposed High Voltage Transmission Revenue Requirement to the FERC and the ISO.

26.1.2 High Voltage Access Charge and Transition Charge Settlement.

UDCs and MSS Operators serving Gross Load in a PTO Service Territory shall be charged on a monthly basis, in arrears, the applicable High Voltage Access Charge and Transition Charge. The High Voltage Access Charge and Transition Charge for a billing period is calculated by the ISO as the product of the applicable High Voltage Access Charge or Transition Charge, as applicable, and Gross Load connected to the facilities of the UDC and MSS Operator in the PTO Service Territory. The High Voltage Access Charge and Transition Charge are determined in accordance with Schedule 3 of Appendix F of the ISO Tariff. These rates may be adjusted from time to time in accordance with Schedule 3 to Appendix F. During the 10-year transition period described in Section 4 of Schedule 3 of Appendix F of the ISO Tariff, a UDC or MSS Operator that is also a Participating TO shall pay, or receive payment of, if applicable, the difference between (i) the High Voltage Access Charge and the Transition Charge applicable to its transactions as a UDC or MSS Operator; and (ii) the disbursement of High Voltage Access Charge revenues to which it is entitled pursuant to Section 26.1.3.

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

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

26.1.4 Wheeling.

Any Scheduling Coordinator or other such entity scheduling a Wheeling transaction shall pay to the ISO the product of (i) the applicable Wheeling Access Charge, and (ii) the total hourly schedules of Wheeling in kilowatt-hours for each month at each Scheduling Point associated with that transaction, except as provided in SPP 4.1. Schedules that include Wheeling transactions shall be subject to the Congestion Management procedures and protocols in accordance with Sections 27.1.1 and 27.1.2.

26.1.4.1 Wheeling Access Charge.

The Wheeling Access Charge shall be determined by the TAC Area and transmission ownership or Entitlement, less all Encumbrances, associated with the Scheduling Point at which the Energy exits the ISO Controlled Grid. The Wheeling Access Charge for Scheduling Points contained within a single TAC Area, that are not joint facilities, shall be equal to the High Voltage Access Charge for the applicable TAC Area in accordance with Section 3 of Appendix F plus the applicable Low Voltage Access Charge if the Scheduling Point is on a Low Voltage Transmission Facility. Wheeling Access Charges shall not apply for Wheeling under a bundled non-economy Energy coordination agreement of a Participating TO executed prior to July 9, 1996.

26.1.4.2 Wheeling Over Joint Facilities.

To the extent that more than one Participating TO owns or has Entitlement to transmission capacity, less all Encumbrances, exiting the ISO Controlled Grid at a Scheduling Point, the Scheduling Coordinator shall pay the ISO each month a rate for Wheeling at that Scheduling Point which reflects an average of the Wheeling Access Charge applicable to those Participating TOs, weighted by the relative share of such ownership or Entitlement to transmission capacity, less all Encumbrances, at such Scheduling Point. If the Scheduling Point is located at High Voltage Transmission Facilities, the Wheeling Access Charge will consist of a High Voltage Wheeling Access Charge component. Additionally, if the Scheduling Point is located at Low Voltage Transmission Facilities, the applicable Low Voltage Wheeling Access Charge component will be added to the Wheeling Access Charge. The methodology for developing the weighted average rate for Wheeling at each Scheduling Point is set forth in Appendix H.

26.1.4.3 Disbursement of Wheeling Revenues.

The ISO shall collect and pay to Participating TOs and other entities as provided in Section 24.7.3 all Wheeling revenues at the same time as other ISO charges and payments are settled. The ISO shall provide to the applicable Participating TO and other entities as provided in Section 24.7.3 a statement of the aggregate amount of Energy delivered to each Scheduling Coordinator using such Participating TO's Scheduling Point to allow for calculation of Wheeling revenue and auditing of disbursements. Wheeling revenues shall be disbursed by the ISO based on the following:

26.1.4.3.1 Scheduling Point with All Participating TOs in the Same TAC Area.

With respect to revenues received for the payment of High Voltage Wheeling Access Charges for Wheeling to a Scheduling Point at which all of the facilities and Entitlements, less all Encumbrances, are owned by Participating TOs in the same TAC Area, Wheeling revenues shall be disbursed to each such Participating TO based on the ratio of each Participating TO's High Voltage Transmission Revenue Requirement to the sum of all such Participating TO's High Voltage Transmission Revenue Requirements. If the Scheduling Point is located at a Low Voltage Facility, revenues received with respect to Low Voltage Wheeling Access Charges for Wheeling to that Scheduling Point shall be disbursed to the Participating TOs that own facilities and Entitlements making up the Scheduling Point in proportion to their Low Voltage Transmission Revenue Requirements. Additionally, if a Participating TO has a transmission upgrade or addition that was funded by a Project Sponsor, the Wheeling revenue allocated to such Participating TO shall be disbursed as provided in Section 24.7.3.

26.1.4.3.2 Scheduling Point without All Participating TOs in the Same TAC Area.

With respect to revenues received for the payment of Wheeling Access Charges for Wheeling to a Scheduling Point at which the facilities and Entitlements, less all Encumbrances, are owned by Participating TOs in different TAC Areas, Wheeling revenues shall be disbursed to such Participating TOs as follows. First, the revenues shall be allocated between such TAC Areas in proportion to the ownership and Entitlements of transmission capacity, less all Encumbrances, at the Scheduling Point of the Participating TOs in each such TAC Area. Second, the revenues thus allocated to each TAC Area shall be disbursed among the Participating TOs in the TAC Area in accordance with Section 26.1.4.3.1.

26.1.4.4 Information Required from Scheduling Coordinators.

Scheduling Coordinators that schedule Wheeling Out or Wheeling Through transactions to a Bulk Supply Point, or other point of interconnection between the ISO Controlled Grid and the transmission system of a Non-Participating TO, that are located within the ISO Control Area, shall provide the ISO, within 5 days from the end of the calendar month to which the relevant Trading Day relates, details of such transactions scheduled by them (other than transactions scheduled pursuant to Existing Contracts) sorted by Bulk Supply Point or point of interconnection for each Settlement Period (including kWh scheduled). The ISO shall use such information, which may be subject to review by the ISO, to settle Wheeling Access Charges and payments. The ISO shall publish a list of the Bulk Supply Points or interconnection points to which this Section 26.1.4.4 applies together with details of the electronic form and procedure to be used by Scheduling Coordinators to submit the required information on the ISO “Home Page”.

26.1.5 Unbundled Retail Transmission Rates.

The Access Charge for unbundled retail transmission service provided to End-Users by a FERC-jurisdictional electric utility Participating TO shall be determined by the FERC and submitted to the ISO for information only. For a Local Publicly Owned Electric Utility, retail transmission service rates shall be determined by the Local Regulatory Authority and submitted to the ISO for information only.

26.2 Tracking Account.

If the Access Charge rate methodology implemented pursuant to Section 26.1 results in Access Charge rates for any Participating TO which are different from those in effect prior to the ISO Operations Date, an amount equal to the difference between the new rates and the prior rates for the remainder of the period, if any, during which a cost recovery plan established pursuant to Section 368 of the California Public Utilities Code (as added by AB 1890) is in effect for such Participating TO shall be recorded in a tracking account. The balance of that tracking account will be recovered from customers and paid to the appropriate Participating TO after termination of the cost recovery plan set forth in Section 368 of California Public Utilities Code (as added by AB 1890). The recovery and payments shall be based on an amortization period not exceeding three years in the case of electric corporations regulated by the CPUC or five years for Local Publicly Owned Electric Utilities.

26.3 Addition of New Facilities After ISO Implementation.

The costs of transmission facilities placed in service after the ISO Operations Date shall be recovered consistent with the cost recovery determinations made pursuant to Section 24.7.

26.4 Effect on Tax-Exempt Status.

Nothing in this Section shall compel any Participating TO to violate any restrictions applicable to facilities financed with tax-exempt bonds or contractual restrictions and covenants regarding the use of transmission facilities.

26.5 Transition Mechanism.

During the ten-year transition period described in Section 4 of Schedule 3 to Appendix F, the Original Participating TOs collectively shall pay to the ISO each year an amount equal to, annually, for all New Participating TOs, the amount, if any, by which the New Participating TO's cost of Existing High Voltage Facilities associated with Gross Loads in the PTO Service Territory of the New Participating TO is increased by the implementation of the High Voltage Access Charge described in Schedule 3 to Appendix F. Responsibility for such payments shall be allocated to Original Participating TOs in accordance with Schedule 3 to Appendix F. Amounts payable by Original Participating TOs under this section shall be recoverable as part of the Transition Charge calculated in accordance with Schedule 3 of Appendix F. Amounts received by the ISO under this section shall be disbursed to New Participating TOs with Existing High Voltage Facilities based on the ratio of each New Participating TO's net increase in costs in the categories described in the first sentence of this section, to the sum of the net increases in such costs for all New Participating TOs with Existing High Voltage Facilities.

ARTICLE III – MARKET OPERATIONS

27 OVERVIEW OF MARKETS.

27.1 Congestion Management.

27.1.1 Zonal Congestion Management.

27.1.1.1 The ISO Will Perform Congestion Management.

27.1.1.1.1 Transmission Congestion.

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

27.1.1.1.1.1 Transmission Capacity Reserved under Existing Contracts will not be Subject to the ISO's Congestion Management Procedures.

27.1.1.1.2 Zone-Based Approach.

The ISO will use a Zone-based approach to manage Congestion. A Zone is a portion of the ISO Controlled Grid within which Congestion is expected to occur infrequently or have relatively low Congestion Management costs. Inter-Zonal Interfaces consist of transmission facilities that are expected to have relatively high Congestion Management costs. For these interfaces, allocation of usage based on the value placed on these interfaces by the Scheduling Coordinators will increase efficient use of the ISO Controlled Grid.

27.1.1.1.3 Types of Congestion.

Congestion that occurs on Inter-Zonal Interfaces is referred to as "Inter-Zonal Congestion." Congestion that occurs due to transmission system Constraints within a Zone is referred to as "Intra-Zonal Congestion." Inter-Zonal Congestion Management will ignore Intra-Zonal Congestion. Intra-Zonal Congestion will be managed in accordance with Tariff Section 27.1.1.6.

27.1.1.1.4 Elimination of Potential Transmission Congestion.

The ISO's Day-Ahead and Hour-Ahead scheduling procedures will eliminate potential Inter-Zonal

Congestion by:

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

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

27.1.1.1.5 Elimination of Real-Time Inter-Zonal Congestion.

In its management of Inter-Zonal Congestion in real time, the ISO will issue Dispatch Instructions as necessary to relieve Inter-Zonal Congestion by Dispatching Generation or Demand, as necessary, based on the Energy Bids in accordance with Section 34.3.2. The ISO will use the RTD Software to alleviate Inter-Zonal Congestion as described in Section 34.3.2.

27.1.1.2 General Requirements for the ISO's Congestion Management.

The ISO's Congestion Management in the Day-Ahead Market and Hour-Ahead Market shall:

27.1.1.2.1 only operate if the Scheduling Coordinators do not eliminate Congestion voluntarily;

27.1.1.2.2 adjust the Schedules submitted by Scheduling Coordinators only as necessary to alleviate Congestion;

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

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

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

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

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

27.1.1.3 Use of Computational Algorithms for Congestion Management and Pricing.

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

27.1.1.4 Adjustment Bids Will Be Used by the ISO to Manage Congestion.

27.1.1.4.1 Uses of Adjustment Bids by the ISO.

27.1.1.4.1.1 The ISO shall use the Adjustment Bids, in both the Day-Ahead Market and the Hour-Ahead Market, to schedule Inter-Zonal Interface capacity to those Scheduling Coordinators which value it the most to reflect the Scheduling Coordinators' implicit values for Inter-Zonal Interface capacity and to determine the prices for the use of Congested Inter-Zonal Interfaces.

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

27.1.1.4.1.3 The ISO shall use Energy Bids from Generating Units and from other resources in the ISO's real-time system operation, for increasing resources' output for Intra-Zonal Congestion Management and to decrement Generation in order to accommodate Overgeneration conditions, including Reliability Must-Run Generation which the ISO requests under Reliability Must-Run Contracts.

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

27.1.1.4.2 Submission of Adjustment Bids.

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

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

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

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

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

27.1.1.4.2.6 The Adjustment Bids that the Scheduling Coordinators submit constitute implicit bids for transmission between Zones on either side of a Congested Inter-Zonal Interface. An Adjustment Bid shall constitute a standing offer to the ISO until it is withdrawn.

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

27.1.1.5 Inter-Zonal Congestion Management.

27.1.1.5.0 Inter-Zonal Congestion Management will use a DC optimal power flow (OPF) program that uses linear optimization techniques with active power (MW) controls only.

27.1.1.5.0.1 Inter-Zonal Congestion Management will involve adjusting Schedules to remove potential violations of Inter-Zonal Interface Constraints, minimizing the Redispatch cost, as determined by the submitted Adjustment Bids that accompany the submitted Schedules.

27.1.1.5.1 The scheduling procedures in the Day-Ahead Market and Hour-Ahead Market will first ascertain, through power flow calculations, whether or not Inter-Zonal Congestion would exist if all of the Preferred and Revised Schedules submitted by the Scheduling Coordinators were accepted by the ISO. If no Inter-Zonal Congestion would exist, then all Inter-Zonal Interface uses will be accepted and the Usage Charges will be zero.

27.1.1.5.2 The purpose of Inter-Zonal Congestion Management is to allocate the use of, and determine the marginal value of, active Inter-Zonal Interfaces. The ISO's Inter-Zonal Congestion Management process will allocate Congested transmission to those users who value it the most and will charge all Scheduling Coordators for their allocated usage of Congested Inter-Zonal Interfaces on a comparable basis. All Scheduling Coordators within a Zone will see the same price for transmitting Energy across a Congested Inter-Zonal Interface, irrespective of the particular locations of their Generators, Demands and external imports/exports. Inter-Zonal Congestion Management will comply with the requirements stated in Sections 27.1.1.2, 27.1.1.4 and 27.1.1.5.

27.1.1.5.2.1 Inter-Zonal Congestion Management will keep each Scheduling Coordinator's portfolio of Generation and Demand (i.e., the Scheduling Coordinator's Preferred Schedule) separate from the portfolios of the other Scheduling Coordinators, as the ISO adjusts the Schedules to alleviate Inter-Zonal Congestion. Inter-Zonal Congestion Management will not involve arranging or modifying trades between Scheduling Coordinators. Each Scheduling Coordinator's portfolio will be kept in balance (i.e., its Generation plus external imports, as adjusted for Transmission Losses, and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) will still match its Demand plus external exports) after the adjustments. Market Participants will have the opportunity to trade with one another and to revise their Schedules during the first Congestion Management iteration in the Day-Ahead Market, and between the Day-Ahead Market and Hour-Ahead Market. Inter-Zonal Congestion Management will also not involve the optimization of Scheduling Coordinator portfolios within Zones (where such apparently non-optimal Schedules are submitted by Scheduling Coordinators). Adjustments to individual Scheduling Coordinator portfolios within a Zone will be either incremental (i.e., an increase in Generation and external imports and a decrease in Demand and external exports) or decremental (i.e., a decrease in Generation and external imports and an increase in Demand and external exports), but not both.

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

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

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

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

27.1.1.5.2.6 If inadequate Adjustment Bids have been submitted to schedule Inter-Zonal Interface capacity on an economic basis and to the extent that scheduling decisions cannot be made on the basis of economic value, the ISO will allocate the available Inter-Zonal Interface capacity to Scheduling Coordinators in proportion to their respective proposed use of that capacity as indicated in their Schedules and shall curtail scheduled Generation and Demand to the extent necessary to ensure that each Scheduling Coordinator's Schedule remains balanced, except for those uses of transmission service under Existing Contracts, which are curtailed in accordance with Sections 16.2.4.2 and 16.2.4.3.

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

27.1.1.5.2.8 The ISO will also publish information, once it is available, regarding tentative prices for the use of Inter-Zonal Interfaces, and Generation shift factors for the use of Inter-Zonal Interfaces, which indicate the relative effectiveness of Generation shifts in alleviating Congestion.

27.1.1.6 Intra-Zonal Congestion Management.

(a) In the hour prior to the beginning of the Settlement Period the ISO may adjust Scheduling Coordinators' Final Schedules to alleviate Intra-Zonal Congestion. Except in those instances where the ISO calls Reliability Must-Run Units as provided in Section 30.6.1 of the ISO Tariff, the ISO will adjust resources in accordance with subsections (b) and (c) of this Section 27.1.1.6.

(b) Except as provided in Section 30.6.1 of the ISO Tariff, in the event of Intra-Zonal Congestion, the ISO shall adjust Generating Units and Curtailable Demands (or Interconnection schedules of System Resources in the Control Areas) to alleviate the Constraints as described in subsection (d) below.

(c) Additional Congestion Relief. In the event that there are insufficient resources which provide financial bids to mitigate Inter-Zonal and Intra-Zonal Congestion, Final Schedules which do not rely on Existing Contracts will be adjusted in real time by allocating transmission capacity on a pro rata basis. Final Schedules which rely on Existing Contracts will be adjusted in real time by allocating transmission capacity in accordance with the operating instructions submitted under Section 16.2.4. With respect to facilities financed with Local Furnishing Bonds the ISO shall adjust Final Schedules in real time in a fashion consistent with Sections 3 and 26.4 of the ISO Tariff, Appendix B of the TCA, and Operating Procedures governing the use of such facilities.

(d) Any Generating Unit dispatched to manage Intra-Zonal Congestion shall: (1) if dispatched to increase its output, be paid the greater of its bid price (or mitigated bid if applicable) or the relevant Market Clearing Price; (2) if dispatched to decrease its output, be charged the lesser of its decremental reference price of the relevant Market Clearing Price. The ISO shall not re-dispatch MSS resources to manage Intra-Zonal congestion as set forth in this Section 27.1.1.6, as provided for in the MSS Agreement. The ISO shall treat hydroelectric resources the same as MSS resources for purposes of managing Intra-Zonal congestion under this Section 27.1.1.6.

27.1.1.6.1 Decremental Bids.

With regard to decremental bids, if Final Hour-Ahead Schedules cause Congestion on the Intra-Zonal interface, the ISO shall, after Dispatching available and effective Reliability Must-Run Units to manage the Congestion, apply the decremental reference prices determined by the independent entity that determines the reference prices for the Automatic Mitigation Procedure (AMP) as described in Appendix P, Attachment A. The ISO shall Dispatch Generating Units according to the decremental reference prices thus established, the resource's effectiveness on the Congestion, and other relevant factors such as Energy limitations, existing contractual restrictions, and Regulatory Must-Run or Regulatory Must-Take status, to alleviate the Congestion after Final Hour-Ahead Schedules are issued. Where the ISO must reduce a Generating Unit's output, the ISO shall Dispatch Generating Units according to the decremental reference prices and not according to Adjustment Bids or Supplemental Energy Bids to alleviate Intra-Zonal Congestion. No Generating Unit shall be Dispatched below its minimum operating level or above its maximum operating level. No Reliability Must-Run Unit shall be Dispatched below the operating level determined by the ISO as necessary to maintain reliability. If Congestion still exists after all Generating Units are Dispatched to their minimum operating levels, the ISO shall instruct Generating Units to shut off in merit order based on their total shut-down costs, beginning with the most expensive unit, where such shut-down costs include the lesser of the cost to start up the Generating Unit or to keep the Generating Unit warm for each Generating Unit with a non-zero Final Day-Ahead Schedule for Energy for the next day. Units shut off due to Congestion as set forth in this Section 27.1.1.6.1 shall be charged the lesser of the decremental reference price for the operating range between zero MW output and the unit's minimum operating level or the relevant Market Clearing Price.

If a Generating Unit shut down according to this Section 27.1.1.6.1 cannot start up in time to meet its next day's Energy Schedules, the ISO shall charge the Scheduling Coordinator for that Generating Unit the lesser of the decremental reference price or the Market Clearing Price at the operating level set forth in the relevant Energy Schedule for any deviation from the next day's Final Day-Ahead Schedules for Energy caused by such shut-down. Charges set forth in this Section 27.1.1.6.1 shall not apply to (1) Reliability Must-Run Units operating solely under their Reliability Must-Run Contracts or (2) units operating during a Waiver Denial Period in accordance with the must-offer obligation.

The ISO shall apply the decremental reference prices to thermal Generating Units and to non-thermal Generating Units. If a Generating Unit is instructed by the ISO to shut down to manage Intra-Zonal Congestion, and is subsequently re-started, the Owner of that Generating Unit may invoice the ISO for the lesser of (1) the Start-Up Costs incurred and (2) the costs of keeping the Generating Unit warm to meet its Energy Schedules as set forth in Section 40.12.6. If the ISO Dispatches System Resources or Dispatchable Loads to alleviate Intra-Zonal Congestion, the ISO shall Dispatch those resources in merit order according to the resource's Day-Ahead or Hour-Ahead Adjustment Bid or Imbalance Energy bid.

The ISO shall only Redispatch Regulatory Must-Take or Regulatory Must-Run Generation, Intermittent Resources, or Qualifying Facilities to manage Intra-Zonal Congestion after Redispatching all other available and effective generating resources, including Reliability Must-Run Units.

27.1.1.6.1.1 Decremental Bid Reference Levels. Decremental bid reference levels shall be determined for use in managing Intra-Zonal Congestion as set forth above in Section 27.1.1.6.1.

(a) Determination. Decremental bid reference levels shall be determined by applying the following steps in order as needed:

1. Excluding non-positive bids, proxy bids, mitigated bids, and bids used out of merit order for managing Intra-Zonal Congestion, the accepted decremental bid, or the lower of the mean or the median of a resource's accepted decremental bids if such a resource has more than one accepted decremental bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for daily changes in fuel prices using gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California

Edison Company, or Pacific Gas and Electric Company), or, if the resource is not served from one of those three Service Areas, from the nearest of those three Service Areas. There will be a six-day time lag between when the gas price used in the daily gas index is determined and when the daily gas index based on that gas price can be calculated. For the purposes of this Section 27.1.1.6.1, to determine whether accepted decremental bids over the previous 90 days were accepted during competitive periods, the independent entity responsible for determining reference prices will apply a test to the prior 90-day period. The test will require that the ratio of a unit's accepted out-of-sequence decremental bids (MWh) for the prior 90 days to its total accepted decremental bids (MWh) for the prior 90 days be less than 50 percent. If this ratio is greater or equal to 50%, accepted decremental bids will be determined to have been accepted in non-competitive periods and cannot be used to determine the decremental reference price. This test would be applied each day on a rolling 90-day basis. One ratio would be calculated for each unit with no differentiation for various output segments on the unit. Accepted and justified decremental bids below the applicable soft cap, as set forth in Section 39.3 of this Tariff, will be included in the calculation of reference prices;

2. A level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined, and provided the Market Participant has provided sufficient data in accordance with specifications provided by the independent entity responsible for determining reference prices;

3. 90 percent of the unit's default Energy Bid determined monthly as set forth in Section 40.7.5 (based on the incremental heat rate submitted to the independent entity responsible for determining reference prices, adjusted for gas prices, determined according to paragraph (a)(1) above, and the variable O&M cost on file with the independent entity responsible for determining reference prices, or the default O&M cost of $6/MWh);

4. 90 percent of the mean of the economic Market Clearing Prices for the units' relevant location during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices determined according to paragraph (a)(1) above; 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 independent entity responsible for determining reference prices shall determine a reference level on the basis of:

i. the independent entity'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 independent entity; or

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

(b) Monotonicity. The decremental bid reference levels ($/MWh bid price) for the different bid segments of each resource shall be made monotonically non-decreasing by the independent entity responsible for determining reference prices by proceeding from the highest MW bid segment moving through each lower MW bid segment. The reference level of each succeeding bid segment, moving from right to left in order of decreasing operating level, shall be the lower of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

27.1.1.6.2 Incremental Bids.

With regard to incremental bids, except as provided in Sections 30.6, 27.1.1.6.1 and 11.2.4.2, the ISO will perform Intra-Zonal Congestion Management in real time using available Imbalance Energy bids, based on their effectiveness and in merit order, to minimize the cost of alleviating Congestion. In the event no Imbalance Energy bids are available, the ISO will exercise its authority to direct the Redispatch of resources as allowed under the Tariff, including Section 16.2.

27.1.1.6.3 Cost of Intra-Zonal Congestion Management.

The net of the amounts paid by the ISO to the Scheduling Coordinators and the amounts charged to the Scheduling Coordinators will be calculated and charged to all Scheduling Coordinators through a Grid Operations Charge, as described in Section 27.1.3.

27.1.1.6.4 [Deletion pending FERC approval]

27.1.1.7 Creation, Modification and Elimination of Zones.

27.1.1.7.1 Active Zones.

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

27.1.1.7.2 Modifying Zones.

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

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

27.1.1.7.2.2 The ISO may, at its own discretion, shorten the 12-month and 90-day periods for creating new Zones if the ISO Governing Board determines that the planned addition of new Generation or Load would result in Congestion that would meet the criterion specified in Section 27.1.1.7.2.1.

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

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

27.1.1.7.3 Active and Inactive Zones.

27.1.1.7.3.1 An Active Zone is one for which a workably-competitive Generation market exists on both sides of the relevant Inter-Zonal Interface for a substantial portion of the year so that Congestion Management can be effectively used to manage Congestion on the relevant Inter-Zonal Interface. Pending the ISO's determination of the criteria for defining "workable competitive generation markets", the Inactive Zones will, as an interim measure, be those specified in Section 27.1.1.7.3.3.

27.1.1.7.3.2 The Congestion Management described in this Section 27.1.1, and the Usage Charges stemming from the application of these procedures, shall not apply to Inter-Zonal Interfaces with Inactive Zones.

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

27.1.1.7.3.4 The determination of whether a new Zone or an existing Inactive Zone should become an Active Zone and the determination of whether a workably-competitive Generation market exists for a substantial portion of the year, shall be made by the ISO Governing Board, using the same approval criteria as are used for the creation or modification of Zones. The ISO Governing Board shall adopt criteria that defines a "workably competitive Generation" market. The ISO Governing Board will review the methodology used for the creation or modification of Zones (including Active Zones and Inactive Zones) on an annual basis and make such changes as it considers appropriate.

27.1.2 Usage Charges and Grid Operations Charges.

27.1.2.0.1 The ISO will collect Usage Charges from Scheduling Coordinators for their Scheduled use of Congested Inter-Zonal Interfaces. If Adjustment Bids are exhausted and

Schedules are adjusted pro rata, the ISO will apply a default Usage Charge calculated in accordance with Section 27.1.2.1.3.1

27.1.2.1 Usage Charges for Inter-Zonal Congestion.

The Usage Charge is used by the ISO to charge Scheduling Coordinators for the use of Congested Inter-Zonal Interfaces. Subject to Section 16.2.3.4.1, the Usage Charge shall be paid by all Scheduling Coordinators that use a Congested Inter-Zonal Interface. If a Scheduling Coordinator uses more than one Congested Inter-Zonal Interface, it will pay a Usage Charge for each Congested Inter-Zonal Interface that it uses.

27.1.2.1.1 Calculation and Allocation of Usage Charge.

Those Scheduling Coordinators who are permitted by the ISO to use a Congested Inter-Zonal Interface will pay a Usage Charge. The Usage Charge is determined using Inter-Zonal Congestion Management described in Section 27.1.1.5, and is calculated as the hourly marginal value of an incremental kW of Inter-Zonal Interface capacity (in cents per kWh). The same Usage Charge will be used to compensate Scheduling Coordinators who, in effect, create transmission capacity through counter Schedules on Congested Inter-Zonal Interfaces.

27.1.2.1.2 Calculation of Marginal Value of an Inter-Zonal Interface.

The marginal value of an Inter-Zonal Interface is the basis for the Usage Charge associated with the scheduled use of the Inter-Zonal Interface. This price is calculated from the Adjustment Bids of the Scheduling Coordinators and the ISO's computer optimization algorithms, using the procedures described in Section 27.1.1.

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

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

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

27.1.2.1.3 Default Usage Charge.

If inadequate or unusable Adjustment Bids have been submitted to the ISO to enable the ISO's Congestion Management to schedule Inter-Zonal Interface capacity on an economic basis, then the ISO will calculate and impose a default Usage Charge, in accordance with Sections 27.1.2.1.3.1 through 27.1.2.1.3.4.

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

27.1.2.1.3.2 The default Usage Charge will be calculated, in accordance with this Section 27.1.2.1.3, by applying a pre-set adder, ranging from $0/MWh to $99/MWh, to the highest incremental Adjustment Bid used, less the applicable decremental Adjustment Bid used; provided that in all cases where there are insufficient decremental Adjustment Bids or no decremental Adjustment Bids available, in the exercise of mitigating Congestion, the applicable decremental price will be set equal to $0/MWh; provided, further, that the ISO may vary the pre-set adder with day-prior notice to Scheduling Coordinators (*e.g.*, applicable to next day's Day-Ahead Market).

27.1.2.1.3.3 Upon the ISO Operations Date, and until such time as the ISO determines otherwise, the ceiling price for the default Usage Charge will be set at $250/MWh; the floor price for the default Usage Charge will be set at $30/MWh; and the pre-set adder that is to be applied in accordance with Section 27.1.2.1.3.2 will be set at $0/MWh.

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

27.1.2.1.3.5 If the Congestion Management software is not capable of calculating the default Usage Charge upon the ISO Operations Date in accordance with Sections 27.1.2.1.3.1 through 27.1.2.1.3.4, the ISO will establish a fixed default Usage Charge within the absolute limits of $0/MWh and $500/MWh, which may be changed by the ISO with day-prior notice. Initially, the default Usage Charge would be capped at $100/MWh. As soon as tested and available, the ISO will implement the Congestion Management software to calculate the default Usage Charge in accordance with Sections 27.1.2.1.3.1 through 27.1.2.1.3.4 after giving at least seven (7) days notice to Scheduling Coordinators, by way of a notice posted on the ISO Internet "Home Page" at http://www.ISO.com or such other Internet address as the ISO may publish from time to time.

27.1.2.1.4 Determination of Usage Charges to be Paid by Scheduling Coordinator.

All Scheduling Coordinators whose Schedules requiring use of a Congested Inter-Zonal Interface have been accepted by the ISO, shall pay a Usage Charge for each hour for which they have been scheduled to use the Inter-Zonal Interface. The amount payable shall be the product of the Usage Charge referred to in Section 27.1.2.1.2 for the particular hour, multiplied by the Scheduling Coordinator's scheduled flows (in kW) and capacity, if any, reserved for Ancillary Services over the Inter-Zonal Interface for that particular hour.

27.1.2.1.5 Determination of Usage Charges to be Paid to Scheduling Coordinators Who Counter-Schedule.

27.1.2.1.5.1 Scheduling Coordinators who in effect create additional Inter-Zonal Interface transmission capacity on Congested Inter-Zonal Interfaces will receive from the ISO a Usage Charge for each hour they have counter-scheduled on the Congested Inter-Zonal Interfaces. The amount payable shall be the product of the Usage Charge referred to in Section 27.1.2.1.2 for that particular hour, multiplied by the Scheduling Coordinator's scheduled flows.

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

27.1.2.1.6 ISO Disbursement of Net Usage Charge Revenues.

The ISO will determine the net Usage Charges on an interface-by-interface basis by subtracting the Usage Charge fees paid to Scheduling Coordinators from the Usage Charge fees paid by Scheduling Coordinators. The net Usage Charge revenues collected by the ISO for each Inter-Zonal Interface shall be, subject to the provisions of Section 27.1.2.1.7 of the ISO Tariff, paid to: (i) FTR Holders, in accordance with Section 36.6; and (ii) to the extent not paid to FTR Holders, to Participating TOs who own the Inter-Zonal Interfaces and Project Sponsors as provided in Section 24.7.3 (in proportion to their respective ownership rights). If a New Participating TO has received FTRs, pursuant to Section 36.4.3, over an Inter-Zonal Interface, the MW of FTRs received shall not be eligible for the disbursement of Usage Charge revenues under part (ii) of this section. Participating TOs will credit in turn the Usage Charge revenue to their Transmission Revenue Balancing Accounts, or, for those Participating TOs that do not have such accounts, to their Transmission Revenue Requirements.

27.1.2.1.7 ISO Debit of Net Usage Charge Revenues.

If, after the issuance of Final Day-Ahead Schedules by the ISO, (a) Participating TOs instruct the ISO to reduce interface limits based on operating conditions or (b) an unscheduled transmission Outage occurs and as a result of either of those events, Congestion is increased and Available Transfer Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the ISO shall: (1) charge each Participating TO and Project Sponsor(s) as provided in Section 24.7.3, and FTR Holder with an amount equal to its proportionate share, based on its financial entitlement to Usage Charges in the Day-Ahead Market in accordance with Section 27.1.2.1.6, of the product of (i) the Usage Charge in the Day-Ahead Market and (ii) the reduction in Available Transfer Capacity across the Inter-Zonal Interface in the direction of the Congestion (such amount due to the Participating TOs to be debited by them in turn from their Transmission Revenue Balancing Accounts or, for those Participating TOs that do not have such accounts, to their Transmission Revenue Requirements); (2) charge each Scheduling Coordinator with its proportionate share, based on Schedules in the Day-Ahead Market across the Inter-Zonal Interface in the direction of the Congestion, of the difference between the amount charged to Participating TOs and Project Sponsors as provided in Section 24.7.3, and FTR Holders under clause (1) and the Usage Charges in the Hour-Ahead Market associated with the reduced Available Transfer Capacity across the Congested Inter-Zonal Interface; and (3) credit each Scheduling Coordinator whose Schedule in the Hour-Ahead Market for the transfer of Energy across the Congested Inter-Zonal Interface was adjusted due to the reduction in Available Transfer Capacity an amount equal to the product of the adjustment (in MW) and the Usage Charge in the Hour-Ahead Market (in$/MW).

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

27.1.3 Grid Operations Charge for Intra-Zonal Congestion.

Scheduling Coordinators whose resources are Redispatched by the ISO, in accordance with Intra-Zonal Congestion Management as set forth in Section 27.1.1.6, will be paid or charged as set forth in Appendix N, Part B. The net Redispatch cost will be recovered for each Settlement Period through the Grid Operations Charge, which shall be paid to the ISO by all Scheduling Coordinators in proportion to their metered Demands within the Zone with Intra-Zonal Congestion, and scheduled exports from the Zone with Intra-Zonal Congestion to a neighboring Control Area, provided that, with respect to Demands within an MSS in the Zone and scheduled exports from the MSS to a neighboring Control Area, a Scheduling Coordinator shall be required to pay Grid Operations Charges only with respect to Intra-Zonal Congestion, if any, that occurs on an interconnection between the MSS and the ISO Controlled Grid, and with respect to Intra-Zonal Congestion that occurs within the MSS, to the extent the Congestion is not relieved by the MSS Operator.

27.2.1 Transmission Losses.

27.2.1.1 Obligation to Provide for Transmission Losses.

Each Scheduling Coordinator shall ensure that it schedules sufficient Generation to meet both its Demand and Transmission Losses responsibilities as determined in accordance with this Section 27.2.1. Scheduling Coordinators for Generators, System Units and System Resources are responsible for their respective proportion of Transmission Losses as determined in accordance with Section 27.2.1.2. For each Final Hour-Ahead Schedule, each Scheduling Coordinator representing Generators, dynamically scheduled System Resources or System Units shall elect through the flag described in Section 30.2.2 to either: 1) generate sufficient additional energy to meet its respective Transmission Losses or 2) be financially responsible for its respective transmission loss obligation based on the Imbalance Energy procured on its behalf by the ISO. Scheduling Coordinators for non-dynamically scheduled System Resources may self-provide transmission losses by scheduling an additional balanced quantity of Energy, both Supply and Demand, equal to their expected transmission loss obligation above their committed delivery quantities in their Hour-Ahead Schedules. In the ISO Imbalance Energy market, all Scheduling Coordinators for Generators, System Units, and System Resources must be financially responsible for all respective Transmission Losses associated with their respective Imbalance Energy Dispatch Instructions in real time, based on the Imbalance Energy procured on their behalf by the ISO. A Scheduling Coordinator for an MSS Operator that has elected to follow Load will be responsible for its transmission loss obligation pursuant to Sections 4.9.9.1 and 4.9.16.4.

27.2.1.1.1 Settlement of Transmission Loss Obligations.

For a Scheduling Coordinator that elects to not or may not, self-provide for its transmission loss obligation, the ISO will procure Imbalance Energy on the Scheduling Coordinator's behalf for each relevant Dispatch Interval and explicitly settle its transmission loss obligation for each applicable Settlement Interval. For a resource under an ISO Dispatch Instruction for Imbalance Energy, transmission loss obligations shall be settled at the Resource-Specific Settlement Interval Ex Post Price. For a resource not under an ISO Dispatch Instruction for Imbalance Energy, transmission loss obligations shall be settled at the simple average of the two applicable Dispatch Interval Ex Post Prices as defined in Section 34.9.2.1. Allocation of transmission loss obligation settlement shall be treated consistent with Instructed Imbalance Energy pursuant to Section 11.2.4.2.1.

27.2.1.2 Determination of Transmission Losses.

The ISO will specify GMMs for each Energy supply source (Generating Units and external imports at Scheduling Points) to account for the Energy lost in transmitting power from Generating Units and/or Scheduling Points to Load. The total Demand that may be served by a Generating Unit, in a given hour, taking account of Transmission Losses, is equal to the product of the total Metered Quantity of that Generating Unit in that hour and the Ex Post Generation Meter Multiplier calculated by the ISO in the hour for that Generator location except in accordance with Section 27.2.1.2.3. The Ex Post Generation Meter Multiplier shall be greater than one (1) where the Generating Unit's contribution to the ISO Controlled Grid reduces Transmission Losses and shall be less than one (1) where the Generating Unit's contribution to the system increases Transmission Losses. All Generating Units supplying Energy to the ISO Controlled Grid at the same electrical bus shall be assigned the same Ex Post Generation Meter Multiplier. Inter-

Scheduling Coordinator Energy Trades will not be subject to such adjustments, beyond the impact of GMMs on the respective Scheduling Coordinator's Generation and external imports.

27.2.1.2.1 Procedures for Calculating Generation Meter Multiplier.

27.2.1.2.1.1 At all times, the ISO will make available Generating Meter Multipliers for the seven Trading Days starting with the Trading Day after the next Trading Day before Scheduling Coordinators submit Day-Ahead Preferred Schedules. By 6:00 p.m. two days preceding a Trading Day, the ISO will calculate, and post on WEnet, an estimated Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. In other words, if the current Trading Day is day 0, the ISO will publish at 6:00 pm today, via WEnet, the GMMs for Trading Days 2 through 8. On Trading Day 1, at 6:00 pm, the ISO will drop the GMMs for Trading Day 1 and add the newly calculated GMMs for Trading Day 9, with the GMMs for Trading Days 3 through 8 remaining the same.

27.2.1.2.1.1.1 The Generation Meter Multipliers shall be determined utilizing the Power Flow Model based upon the ISO's forecasts of total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO will calculate and publish GMMs for each Settlement Period to reflect different expected Generation and Demand patterns and expected operations and maintenance requirements, such as line Outages, which could affect Transmission Loss determination and allocation. The ISO shall continuously update the data to be used in calculating the Generation Meter Multipliers to reflect changes in system conditions on the ISO Controlled Grid, and the ISO shall provide all Scheduling Coordinators with access to such data. The ISO shall not be required to determine new Generation Meter Multipliers for each hour; the ISO will determine the appropriate period for which each set of Generation Meter Multipliers will apply, which period may vary based upon the expected frequency and magnitude of changes in system conditions on the ISO Controlled Grid.

27.2.1.2.1.2 The ISO will calculate the Ex Post Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. The Ex Post Generation Meter Multipliers shall be determined utilizing the real-time Power Flow Model based upon the ISO's total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO's total Demand shall be determined using real-time power flow data based on a state-estimation result. Any difference between scheduled and Ex Post Transmission Losses will be considered as an Imbalance Energy deviation and will be purchased or sold in the Real Time Market at the Settlement Interval Ex Post Price.

27.2.1.2.2 Methodology for Calculating Generation Meter Multiplier.

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

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

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

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

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

27.2.2 Generation Meter Multipliers

27.2.2.1 Temporary Simplification Relating to GMM Loss Factors Application

Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, in determining whether a Schedule is a Balanced Schedule, no allowance shall be made for Transmission Losses (i.e., the Generation Meter Multiplier shall be set at 1.0) for all Scheduling Coordinators.

27.2.2.2 Application.

Notwithstanding any other provision in this Tariff, including the ISO Protocols, the temporary simplification measure specified in this Section 27.2.2 shall have effect until discontinued by a Notice of Full-Scale Operations issued by the Chief Executive Officer of the ISO.

27.2.2.2.1 Pursuant to Subsections 27.2.2.3.1 and 27.2.2.3.2, the Chief Executive Officer of the ISO shall give notice to all Scheduling Coordinators that such Scheduling Coordinators shall use forecasted Generation Meter Multipliers, as published by the ISO, in their Schedules. Such notice shall be given only after the Chief Executive Officer determines that the ISO is capable of accepting Schedules using the forecasted Generation Meter Multipliers without adversely affecting operations or reliability.

27.2.2.3 Notices of Full-Scale Operations.

27.2.2.3.1 When the Chief Executive Officer of the ISO determines that the ISO is capable of implementing this Tariff, including the ISO Protocols, without modification in accordance with a temporary simplification measure specified in this Section 27.2.2, he shall issue a notice ("Notice of Full-Scale Operations") and shall specify the relevant temporary simplification measure and the date on which it will permanently cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.

27.2.2.3.2 A Notice of Full-Scale Operations shall be issued when it is posted on the ISO Internet "Home Page," at http://www.ISO.com or such other Internet address as the ISO may publish from time to time.

28 TRADES BETWEEN SCHEDULING COORDINATORS.

Billing and settling an Inter-Scheduling Coordinator Energy or Ancillary Service Trade shall be done in accordance with the agreements between the parties to the trade. The parties to an Inter-Scheduling Coordinator Energy or Ancillary Service Trade shall notify the ISO, in accordance with the ISO Protocols, of the Zone in which the transaction is deemed to occur, which, for Inter-Scheduling Coordinator Energy Trades, shall be used for the purpose of identifying which Scheduling Coordinator will be responsible for payment of applicable Usage Charges;

29 [Not Used]

30 BIDS AND BID SUBMISSION.

30.1 ISO Operations.

30.1.1 Scheduling.

30.1.3 ISO Scheduling Responsibilities.

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

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

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

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

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

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

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

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

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

30.2.1 For Demand:

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

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

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

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

30.2.1.5 Scheduling Coordinator's ID code;

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

30.2.1.7 type of Schedule: Preferred or Revised;

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

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

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

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

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

30.2.1.13 requisite NERC tagging data.

30.2.2 For Generation:

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

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

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

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

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

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

30.2.2.7 Scheduling Coordinator's ID code;

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

30.2.2.9 name of Generating Unit scheduled;

30.2.2.10 type of Schedule: Preferred or Revised;

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

30.2.2.12 contract reference number for Reliability Must-Run Generation;

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

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

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

30.2.2.15 Generating Unit ramp rate in MW/minute;

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

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

30.2.2A The Generation section of a Balanced Schedule, and any associated Adjustment Bids, must accurately reflect the physical capability of each Generating Unit identified in the Schedule (including each Generating Unit's ability to ramp from one hour to the next). For example, a 500 MW Generating Unit specified with a ramp rate of 2 MW/min and an operating point of 100 MWh for the current operating hour is not physically capable of generating 300 MWh in the next operating hour. Likewise, Adjustment Bids submitted for a Generating Unit, applicable to a particular operating hour, should be physically achievable within the applicable operating hour.

30.2.3 For deliveries to/from other Scheduling Coordinators:

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

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

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

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

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

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

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

30.2.3.7 **[Not Used]**

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

30.2.3.9 trading Scheduling Coordinator (buyer or seller);

30.2.3.10 type of Schedule: Preferred or Revised;

30.2.3.11 Schedule type – Energy (ENGY);

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

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

30.2.3.14 publish Adjustment Bid flag – “Yes” indicates that the Scheduling Coordinator wishes the ISO to publish its Adjustment Bid.

30.2.4 For Self-Provided Ancillary Services:

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

30.2.5 For Interruptible Imports:

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

30.2.6 For External Imports/Exports:

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

30.2.6.1 Scheduling Coordinator’s ID code;

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

30.2.6.3 Scheduling Point (the name);

30.2.6.4 type of Schedule: Preferred or Revised

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

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

30.2.6.7 external Control Area ID;

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

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

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

30.2.6.11 Schedule ID (NERC ID number);

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

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

30.2.6.14 Complete NERC tag;

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

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

30.2.6.17 for dynamically scheduled imports only, the transmission loss self-provision flag (LOSS_CMP_FLG): "Yes" indicates that Dispatch Instructions provided to the resource will include Transmission Losses associated with the resource's Final Hour-Ahead Schedule as determined by the relevant GMM.

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

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

30.2.7.1 Scheduling Coordinator's ID code:

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

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

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

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

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

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

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

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

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

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

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

(4) Energy type – firm (FIRM), non-firm (NFIRM), Wheeling (WHEEL), dynamic (DYN),

Energy (ENGY), Spinning Reserve (CSPN), Non-Spinning Reserve (CNSPN) or Replacement Reserve (CRPLC); and

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

30.2.8 Content and Format of Adjustment Bids

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

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

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

30.3 The Scheduling Process.

The ISO scheduling process is described for information purposes only in tabular form in Appendix C.

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

30.3.1 Preferred Schedule.

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

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

30.3.2 Seven-Day Advance Schedules.

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

30.3.3 Suggested Adjusted Schedules.

In the Day-Ahead scheduling process, if the sum of Scheduling Coordinators' Preferred Schedules would cause Congestion across any Inter-Zonal Interface, the ISO shall issue to all Scheduling Coordinators an estimate of the Usage Charges if Congestion is not relieved and Suggested Adjusted Schedules that shall reflect adjustments made by the ISO to each Scheduling Coordinator's Preferred Schedule to eliminate Congestion, based on the initial Adjustment Bids submitted in the Preferred Schedules. The ISO will include in the Suggested Adjusted Schedules the resolution of any mismatches in Inter-Scheduling Coordinator Energy Trades, as determined by the ISO. These Suggested Adjusted Schedules will not apply to uses of transmission owned by Non-Participating TOs nor to uses of Existing Rights. A modification flag, set by the ISO, will indicate whether the scheduled output in a Settlement Period has been modified as a result of Congestion Management.

30.3.4 Revised Schedules.

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

30.3.4.1 Final Schedules.

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

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

30.3.4.2 Scheduling and Real-Time Information.

30.3.4.3 Final Schedules.

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

30.3.4.4 The Final Schedule will include information with respect to:

(a) Generation schedules;

(b) Demand schedules;

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

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

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

(f) Inter-Scheduling Coordinator Energy Trades.

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

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

30.3.5A No Scheduling Coordinator shall submit a Circular Schedule. The ISO may periodically provide examples of such Circular Schedules under the ISO Home Page.

30.4 Verification of Information.

The ISO shall be entitled to take all reasonable measures to verify that Scheduling Coordinators meet the technical and financial criteria set forth in Section 4.5.1 hereof and the accuracy of information submitted to the ISO pursuant to Section 30.2.

30.4.1 Validation of Balanced Schedules.

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

30.4.1.1 Stage One Validation.

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

30.4.1.2 Stage Two Validation.

During stage two validation, Schedules will be checked to determine whether each Scheduling Coordinator’s aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) equals the Scheduling Coordinator’s aggregate Demand, including external exports. The Scheduling Coordinator must take into account the applicable Generation Meter Multipliers (GMMs). The Scheduling Coordinator will be notified if the counterpart trade to any Inter-Scheduling Coordinator Ancillary Service Trade has not been submitted, or is infeasible (i.e., if both Scheduling Coordinators are selling or both are buying).

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

30.4.2 Validation of Existing Contract Schedules.

Each Schedule submitted to the ISO by a Scheduling Coordinator representing a rights holder to an Existing Contract must include a valid contract reference number in accordance with Section 16.2.4A.1. If the Schedule includes an Inter-Scheduling Coordinator Trade, only one of the Scheduling Coordinators should submit a contract reference number. If a match of the Schedule's contract reference number is found in the ISO's database and the Schedule is consistent with the instructions submitted previously by the Responsible PTO, the Schedule will be implemented in accordance with the instructions. If a match of the Schedule's contract reference number cannot be found in the ISO's database or if both Scheduling Coordinators which are parties to an Inter-Scheduling Coordinator Trade submit contract reference numbers, the ISO will issue an error message to the Scheduling Coordinator via the WEnet (as described in Section 30.4.1.1) and indicate the nature of the problem. The ISO will assist the Scheduling Coordinator, within reason, in resolving the problem so that the Scheduling Coordinator is able to submit the Schedule successfully as soon as possible within the ISO's timing requirements of the SP. If the Scheduling Coordinator uses a contract reference number for which the responsible PTO has not reserved transmission capacity on a particular path (i.e., the contract reference Number(s) included on a contract usage template cannot be found in the ISO's scheduling applications table of contract reference numbers), the Scheduled use will be invalidated and the Scheduling Coordinator notified by the ISO's issuance of an invalidated usage information template.

30.4.3 Validation of Adjustment Bids.

30.4.3.1 Invalidation.

The absence of an Adjustment Bid in a Scheduling Coordinator's Preferred Schedule or Revised Schedule will not affect the validation since Scheduling Coordinators are not required to submit Adjustment Bids. If an Adjustment Bid is contained in the Scheduling Coordinator's Preferred Schedule or Revised Schedule but is not in the form described above, both the Schedule and the Adjustment Bid will be rejected. The Scheduling Coordinator will be notified immediately, via WEnet, of any validation errors. For each error detected, an error message will be generated by the ISO in the Scheduling Coordinator's notification screen which will specify the nature of the error. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit if it is still within the timing requirements of the SP. The Scheduling Coordinator is also notified of successful validation via WEnet. The Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Adjustment Bids.

30.4.3.2 Validation Checks.

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

30.4.4 Validation of Ancillary Services Bids.

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

30.4.4.1 Stage One Validation.

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

30.4.4.2 Stage Two Validation.

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

30.4.4.3 Validation Checks.

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

30.4.5 Validation of Energy Bids.

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

30.4.6 Format and Validation of Operational Ramp Rates.

The submitted operational ramp rate expressed in megawatts per minute (MW/min) as a function of the operating level, expressed in megawatts (MW), must be a staircase function with up to nine segments defined by a set of 1 to 10 pairs, e.g., (50,1),(100,3),(200,2), (300,2). There is no monotonicity requirement for the operational ramp rate. The submitted operational ramp rate shall be validated as follows:

- The range of the submitted operational ramp rate must cover the entire capacity of the resource, from the minimum to the maximum operating capacity, as registered in the Master File for the relevant resource.

- The operating level entries must match exactly (in number, sequence, and value) the corresponding minimum and maximum operational ramp rate breakpoints, as registered in the Master File for the relevant resource.

- If a Scheduling Coordinator does not submit an operational ramp rate for a generating unit for a day, the ISO shall use the maximum ramp rate for each operating range set forth in the Master File as the ramp rate for that unit for that same operating range for that day.

- The last ramp rate entry shall be equal to the previous ramp rate entry and represent the maximum operating capacity of the resource as registered in the Master File. The resulting operational ramp rate segments must lie between the minimum and maximum operational ramp rates, as registered in the Master File.

- The submitted operational ramp rate must be the same for each hour of the Trading Day, i.e., the operational ramp rate submitted for a given hour must be the same with the one(s) submitted earlier for previous hours in the same Trading Day.

- Outages that affect the submitted operational ramp rate must be due to physical constraints, reported in SLIC and are subject to ISO approval. All approved changes to the submitted operational ramp rate will be used in determination of Dispatch Instructions for the shorter period of the balance of the Trading Day or duration of reported Outage.

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

30.4.7 Format and Validation of Startup and Shutdown Times.

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

- The first down time must be 0 min.

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

- The startup time for each segment must not exceed the startup time of the corresponding segment of the maximum startup time function, as registered in the Master File for the relevant resource.

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

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

30.4.8 Format and Validation of Startup and Shutdown Costs.

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

- The first down time must be 0 min.
- The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the cost-based startup cost function, as registered in the Master File for the relevant resource.
- The startup cost for each segment must not be negative and must not exceed the startup cost of the corresponding segment of the cost-based startup cost function, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based startup cost function shall be derived from the startup fuel function, as registered in the Master File for the relevant resource, and the applicable gas price index as approved by FERC.
- The startup cost function must be strictly monotonically increasing, i.e., the startup cost must increase as down time increases.

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

30.4.9 Format and Validation of Minimum Load Costs.

For a Generating Unit, the submitted Minimum Load Cost expressed in dollars per hour ($/hr) is the cost incurred for operating the unit at minimum load. The submitted Minimum Load Cost must not be negative and must not exceed the cost-based Minimum Load Cost, as registered in the

Master File for the relevant resource. For gas-fired resources, the cost-based Minimum Load Cost shall be derived pursuant to Section 40.8.4.

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

30.5 [Not Used]

30.6 RMR.

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

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

30.6A.1.1 If the ISO, pursuant to Section 8.5.4(e), has elected to procure an amount of megawatts of its forecast needs for an Ancillary Service in the Hour-Ahead Markets and there is not an adequate amount of capacity bid into an Hour-Ahead Market for the ISO to procure such amount of megawatts of that Ancillary Service (excluding bids that exceed price caps imposed by the ISO or FERC), the ISO may call upon Reliability Must-Run Units under Must-Run Contracts to meet the remaining portion of that amount of megawatts for that Ancillary Service but only after accepting all available bids in the Hour-Ahead Market (including any unused bids that can be used to satisfy that particular Ancillary Services requirement under Section 8.2.3.6), except that the ISO shall not be required to accept bids that exceed price caps imposed by the ISO or the FERC.

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

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

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

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

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

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

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

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

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

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

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

30.6A.4 A *pro forma* of the Reliability Must-Run Contract is attached as Appendix G. From the ISO Operations Date all Reliability Must-Run Units will be placed under the “As Called” conditions, but the parties may, pursuant only to the terms of the Reliability Must-Run Contract, Transfer any such unit to one of the alternative forms of conditions under specific circumstances. The ISO will review the terms of the applicable forms of agreement applying to each Reliability Must-Run Unit to ensure that the ISO will procure Reliability Must-Run Generation from the cheapest available sources and to maintain System Reliability. The ISO shall give notice to terminate Reliability Must-Run Contracts that are no longer necessary or can be replaced by less expensive and/or more competitive sources for maintaining the reliability of the ISO Controlled Grid.

30.6.1.1 Reliability Must-Run Charge.

The ISO shall prepare and send to each Responsible Utility in accordance with Appendix N, Part J an ISO Invoice in respect to those costs incurred under each Reliability Must-Run Contract that are payable to the ISO by such Responsible Utility or payable by the ISO to such Responsible Utility pursuant to Section 30.6.1.2. The ISO Invoices shall reflect all reductions or credits required or allowed under or arising from the Reliability Must-Run Contract or under this Section 30.6.1.1. The ISO Invoice shall separately show the amounts due for services from each RMR Owner. Each Responsible Utility shall pay the amount due under each ISO Invoice by the due date specified in the ISO Invoice, in default of which interest shall become payable at the interest rate provided in the Reliability Must-Run Contract from the due date until the date on which the amount is paid in full. For each Reliability Must-Run Contract, the ISO shall establish two, segregated commercial bank accounts under the "Facility Trust Account" referred to in Appendix N, Part J and Article 9 of the Reliability Must-Run Contract. One commercial bank account, the "RMR Owner Facility Trust Account," shall be held in trust by the ISO for the RMR Owner. The other commercial bank account, the "Responsible Utility Facility Trust Account," shall be held in trust by the ISO for the Responsible Utility. Payments received by the ISO from the Responsible Utility in connection with the Reliability Must-Run Contract, including payments following termination of the Reliability Must-Run Contract, will be deposited into the RMR Owner Facility Trust Account and payments from the ISO to the RMR Owner will be withdrawn from such account, in accordance with Section 30.6.1.1, Article 9 of the Reliability Must-Run Contract and Appendix N, Part J. Any payments received by the ISO from the RMR Owner in connection with the Reliability Must-Run Contract will be deposited into the Responsible Utility Facility Trust Account. Any payments due to the Responsible Utility of funds received from the RMR Owner in connection with the Reliability Must-Run Contract will be withdrawn from the Responsible Utility Facility Trust Account, in accordance with this Section 30.6.1.1, Appendix N, Part J and Article 9 of the Reliability Must-run Contract. Neither the RMR Owner Facility Trust Account nor the Responsible Utility Trust Account shall have other funds commingled in it at any time. The ISO shall not modify this Section 30.6.1.1 or Appendix N, Part J as it applies to procedures for the billing, invoicing and payment of charges under Reliability Must-Run Contracts without the Responsible Utility's consent, provided, however, that no such consent shall be required with respect to any change in the method by which costs incurred by the ISO under RMR Contracts are allocated to or among Responsible Utilities.

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

30.6.1.1.1.1 If the Responsible Utility disputes an ISO Invoice, Revised Estimated RMR Invoice, or Revised Adjusted RMR Invoice, or Final Invoice, it shall pay the ISO Invoice but may pay under protest and reserve its right to seek a refund, with interest, from the ISO. If resolution of the dispute results in an amount paid by the Responsible Utility under protest being due from the ISO to the Responsible Utility and from the RMR Owner to the ISO, and such amount was paid to the RMR Owner by the ISO, then such amount, with interest at the interest rate specified in the applicable Reliability Must-Run Contract from the date of payment until the date on which the amount is repaid in full, shall be refunded by the RMR Owner to the ISO and from the ISO to the Responsible Utility, pursuant to Article 9 of the Reliability Must-Run Contract and Appendix N, Part J, by the RMR Owner's inclusion of such refund amount in the appropriate invoice. If the RMR Owner does not include such refund amount (including interest) in the appropriate invoice, then such refund amount shall be deducted by the ISO from the next succeeding amounts otherwise due from the Responsible Utility to the ISO and from the next succeeding amounts otherwise due from the ISO to the RMR Owner with respect to the applicable Reliability Must-Run Contract or, if such Contract has terminated, such amount shall be refunded by the ISO to the Responsible Utility; provided, however, that if and to the extent that such resolution is based on an error or breach or default of the RMR Owner's obligations to the ISO under the Reliability Must-Run Contract, then such refund obligation shall extend only to amounts actually collected by the ISO from the RMR Owner as a result of such resolution. If resolution of the dispute requires the ISO, but not the RMR Owner, to pay the Responsible Utility, then such award shall be recovered from any applicable insurance proceeds, provided that to the extent sufficient funds are not recoverable through insurance, the amount of the award (whether determined through settlement, or ADR or otherwise) shall be collected by the ISO pursuant to Section 13.5, and in any event, the award shall be paid by the ISO to the Responsible Utility pursuant to Section 13.5.

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

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

30.6.1.1.1.4 Notwithstanding Section 13 of this ISO Tariff, any Responsible Utility dispute relating to an ISO Invoice, a Revised Estimated Invoice, a Revised Adjusted Invoice, a Final Invoice, or a RMR Charge, RMR Payment or RMR Refund as defined in Appendix N, Part J, shall be resolved through the dispute resolution process specified in the relevant RMR Contract. If the Responsible Utility fails to notify the ISO of any dispute as provided above, it shall be deemed to have validated the invoice and waived its right to dispute such invoice.

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

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

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

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

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

30.6.1.2 Responsibility for Reliability Must-Run Charge.

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

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

If the ISO procures Reliability Must-Run Generation from the San Onofre Nuclear Generation Station Units 2 or 3, it shall determine prior to the operation of such facilities as Reliability Must-Run Generation the appropriate allocation of associated charges, if any, among Responsible Utilities. The allocation of such charges shall be based on the reliability benefits that the ISO reasonably identifies through studies and analysis as accruing to the respective Service Areas of the Responsible Utilities.

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

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

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

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

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

(5) The ISO does not have to revoke or deny a waiver to a Generating Unit (a) subject to environmental limitations if doing so would violate such limitations, or cause the Generating Unit to be unavailable in the future, or if the environmental limitations currently restrict the

availability or use of the Generating Unit; or (b) if that Generating Unit would cause or exacerbate Congestion, Overgeneration or other operational problem; or (c) if that Generating Unit is incapable of being available for Dispatch in the required timeframe.

Notwithstanding anything to the contrary in the applicable RMR Contract, all MWh, start-ups and service hours provided by a Generating Unit that has currently selected Condition 2 of its RMR Contract pursuant to this Section 30.6.1.2.2 outside of the RMR Contract shall not be used to determine future RMR Contract Annual Service Limits. Payment for Dispatches pursuant to this Section 30.6.1.2.2 is governed by Section 11.2.4.2 of this Tariff.

30.6.1.3 Identification of Generating Units.

Each Generator shall provide data identifying each of its Generating Units and such information regarding the capacity and the operating characteristics of the Generating Unit as may be reasonably requested from time to time by the ISO.

31 DAY-AHEAD MARKET.

31.1 Timing of Day-Ahead Scheduling.

31.1A The ISO may in its sole discretion implement any temporary variation or waiver of the timing requirements of this Section 31.1 (including the omission of any step) if any of the following criteria are met:

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

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

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

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

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

If the ISO temporarily implements a waiver or variation of such timing requirements, 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;

(iv) reasons for the temporary waiver or variation.

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

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

31.1.1 Reliability Must Run Information.

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

31.1.1.1 No later than 6:00 a.m. on the day before the Trading Day, any RMR Owner receiving an RMR Dispatch Notice as indicated in this Section 31.1.1.1 (the "Applicable RMR Owner") must notify the ISO through the RMR Owner's Scheduling Coordinator (the "Applicable RMR SC"), with regard to each hour of the Trading Day identified in the RMR Dispatch Notice whether it intends to satisfy its obligation to deliver RMR Energy (i) by delivering RMR Energy pursuant to a market transaction ("RMR Market Energy"), and receiving only market compensation therefore (the "RMR Market Option"), or (ii) by delivering RMR Energy as a contract transaction ("RMR Contract Energy"), and accepting payment under the relevant RMR Contract (the "RMR Contract Option"). If the Applicable RMR Owner so notifies the ISO by March 1, 2001, for calendar year 2001, and by January 1 of any subsequent calendar year, the RMR Owner may during that calendar year notify the ISO directly of its choice of payment option, rather than through the Applicable RMR Owner's Scheduling Coordinator. If the Applicable RMR Owner elects to provide notice of its choice of payment option directly, the ISO will not accept notice from the Applicable RMR Owner's Scheduling Coordinator during the relevant calendar year. Notwithstanding anything to the contrary in any RMR Contract, the Applicable RMR Owner may not elect to satisfy its obligation to deliver the RMR Energy specified in the RMR Dispatch Notice by delivering that RMR Energy pursuant to a transaction in the Real Time Market.

31.1.2 RMR Contract Option.

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

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

31.1.2.1 [Not Used]

31.1.3 RMR Market Option.

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

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

The Preferred Day-Ahead Schedule of the Applicable RMR Scheduling Coordinator shall include as RMR Market Energy for each hour the sum of the amount awarded to the Applicable RMR Owner in any power exchange market for that hour and the amount scheduled as a bilateral Day-Ahead transaction for that hour. If the Preferred Day-Ahead Schedule of the Applicable RMR Scheduling Coordinator for any hour includes Adjustment Bids for the RMR Unit, the Adjustment Bid shall specify the RMR Market Energy as the minimum MW output to which the Applicable RMR Scheduling Coordinator will allow the RMR Unit to be redispatched for that hour.

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

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

31.1.3.2.1 The Applicable RMR Scheduling Coordinator's Preferred Hour-Ahead Schedule for each hour shall include all RMR Market Energy specified in the RMR Dispatch Notice for that hour, except for the amount of RMR Energy that the Applicable RMR Owner was required to bid into the power exchange markets under Section 31.1.3.2 but was not awarded in such power exchange markets for such hour. If the Preferred Hour-Ahead Schedule of the Applicable RMR Scheduling Coordinator for any hour includes

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

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

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

31.1.3.5 [Not Used]

31.1.4 Demand Information.

31.1.4.1 Daily Information. By 10:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator shall provide to the ISO a Demand Forecast specified by UDC or MSS Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day; however, the requirements of this Section shall not apply to (a) the portion of a Scheduling Coordinator's Demand associated with Station Power and (b) the Scheduling Coordinator's Demand within a UDC or MSS Service Area if the Scheduling Coordinator's maximum Demand within that UDC or MSS Service Area during the preceding twelve (12) months was less than one (1) megawatt, provided that this exemption shall not apply to any Scheduling Coordinator that did not submit Schedules for any metered Demand within a UDC or MSS Service Area over the preceding twelve (12) month period. The ISO shall aggregate the Demand information by UDC or MSS Service Area and transmit the aggregate Demand information to each UDC or MSS serving such aggregate Demand.

31.1.4.2 Preliminary Weekly Information. Each Scheduling Coordinator shall provide to the ISO, no later than seven (7) days after the end of each week, which shall end at Sunday HE 24, data for the previous week (Monday through Sunday), in electronic format, comparing, for each hour of that week: (1) the Scheduling Coordinator's total Day-Ahead scheduled Demand by UDC Service Area, as submitted pursuant to Section 4.5.4.2, (2) the Scheduling Coordinator's total Day-Ahead Demand Forecast by UDC Service Area, as submitted pursuant to Section 31.1.4.1, and (3) an estimate of the Scheduling Coordinator's actual Demand by UDC Service Area. The requirements of this section do not apply to (a) the portion of a Scheduling Coordinator's Demand associated with Station Power and (b) the Scheduling Coordinator's Demand within a UDC or MSS Service Area if the Scheduling Coordinator's Maximum

Demand within the UDC or MSS Service Area during the preceding twelve (12) months was less than one (1) megawatt, provided that this exemption shall not apply to any Scheduling Coordinator that did not submit Schedules for any metered Demand within a UDC or MSS Service Area over the preceding twelve (12) month period.

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

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

31.1.7 ISO Analysis of Preferred Schedules.

On receipt of the Preferred Schedules, the ISO will analyze the Preferred Schedules of Applicable RMR

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

31.1.8 Issuance of Suggested Adjusted Schedules.

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

31.1.9 Submission of Revised Schedules.

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

31.1.9.1 Revised Schedules Become Final Day-Ahead Schedules.

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

31.1.9.2 Use of Congestion Management for Final Schedule.

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

32 [Not Used]

33 HOUR AHEAD.

33.1 Timing of Hour-Ahead Scheduling.

33.1.1. Submission of Preferred Schedule.

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

33.1.1.1 Statements in Preferred Schedule.

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

33.1.1.2 Final Hour-Ahead Schedule Submission.

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

33.1.2 ISO Analysis of Preferred Schedules.

The ISO shall analyze the combined Preferred Schedules submitted by all Scheduling Coordinators to forecast the probability of Congestion being caused by the Preferred Schedules.

33.1.2.1 Preferred Schedules Become Final Hour-Ahead Schedules.

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

33.1.2.2 Congestion Management Provisions for Final Hour-Ahead Schedules.

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

33.1.2.3 Final Hour-Ahead Schedules.

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

33.1.2.3.1 Generation.

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

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

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

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

33.1.2.3.1.5 [Not Used]

33.1.2.3.2 Load.

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

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

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

33.1.2.4 Usage Charges. The ISO shall notify each Scheduling Coordinator of the applicable Usage Charge calculated in accordance with Section 27.1.2.

34 REAL-TIME.

34.1 Energy Bids.

34.1.1 Energy Bid Definition.

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

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

34.1.2 Energy Bid Submission.

34.1.2.1 Real Time Market.

Bids shall be submitted for use in the real-time Hourly Pre-Dispatch Section 34.3.0.2(i) and the Real-Time Economic Dispatch up to sixty-two (62) minutes prior to the Operating Hour. Resources required to offer their Available Generation in accordance with Section 40.7.4 shall be required to submit Energy Bids for

1) all of their Available Generation and 2) any Ancillary Services capacity awarded or self-provided in the Day-Ahead or Hour-Ahead Ancillary Services markets. In the absence of submitted bids, default bids will be used for resources required to offer their Available Generation in accordance with Section 40.7.4. Resources not required to offer their Available Generation in accordance with Section 40.7.4 that were awarded or self-provided Ancillary Services capacity must submit an Energy Bid for no less than the amount of awarded or self-provided Ancillary Services capacity. Resources not required to offer their Available Generation in accordance with Section 40.7.4 may voluntarily submit Energy Bids. Submitted Energy Bids shall be subject to the Damage Control Bid Cap as set forth in Section 39.1 and to the Mitigation Measures set forth in Attachment A to Appendix P.

34.1.2.1.1 Frequently Mitigated Adders

Generating Units of Participating Generators for which the ISO denies a must-offer waiver request and for which only a portion of their capacity is Eligible Capacity, as well as self-scheduled Generating Units of Participating Generators that have Eligible Capacity, that submit Supplemental Energy bids that are mitigated under Section 3.2.2.2 of Appendix P five times in a single Trading Day, based on five-minute dispatch periods, shall receive a supplemental payment adder ("Frequently Mitigated Adder") for the Dispatched Energy that is mitigated for each mitigated interval in that Trading Day beginning with the 10-minute settlement interval of the fifth mitigation and continuing for each following 10-minute settlement interval through the remainder of the Trading Day, provided that the Frequently Mitigated Adder plus the Mitigated Price does not exceed the resources' original Supplemental Bid. The Frequently Mitigated Adder shall be $40 per megawatt hour multiplied by the ratio of the Eligible Capacity (excluding any portion of minimum load capacity that is not also Resource Adequacy, RMR or designated under RCST) to the total Qualifying Capacity (excluding minimum load level) of the Generating Unit. Generating Units shall not receive Frequently Mitigated Adders in connection with decremental dispatches.

The total amount of Frequently Mitigated Adders that any Generating Unit can receive in a Trading Day shall not exceed the Must-Offer Capacity Payment that the Generating Unit would have received pursuant to Section 40.14 if the ISO had denied a must-offer waiver denial request. Further, Frequently Mitigated

Adders will stop accruing in any calendar month once the combined value for that month of Frequently Mitigated Adders, Must-Offer Capacity Payments and Minimum Load imbalance energy payments under Section 40.8.3 reaches the level of the Monthly RCST Charge (established in Schedule 6 of Appendix F) reduced by the PER (established in Schedule 6 of Appendix F) for that month multiplied by the megawatts of Eligible Capacity of that Generating Unit. This Section 34.1.2.1.1 shall expire at midnight on the earlier of December 31, 2007 or the date immediately before the MRTU goes into effect.

34.1.2.1.2 Allocation of Frequently Mitigated Adder Costs

Costs incurred under Section 34.1.2.1.1 will be allocated in accordance with Section 27.1.3.

34.1.2.2 Real-Time Energy Bid Partition.

The portion of the single Energy Bid that corresponds to the high end of the resource's operating range, shall be allocated to any awarded or self-provided Ancillary Services in the following order from higher to lower capacity: (a) Regulation Up; (b) Spinning Reserve; (c) Non-Spinning Reserve; and (d) Replacement Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid (i.e. that portion not associated with capacity committed to provide Ancillary Services) shall constitute a Bid to provide Supplemental Energy.

34.1.2.3 Creation of the Real-Time Merit Order Stack.

34.1.2.3.1 Sources of Imbalance Energy.

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

(a) Supplemental Energy Bids;

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

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

34.1.2.3.2 Stacking of the Energy Bids.

The sources of Imbalance Energy described in Section 34.1.2.3.1 will be arranged in order of increasing Energy Bid prices to create a merit order stack. This merit order stack will be arranged without regard to the source of the Energy Bid except that Energy Bids associated with Spinning and Non-Spinning Reserve shall not be included in the merit order stack during normal operating conditions if the capacity associated with such bids has been designated as available to supply Imbalance Energy only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency. In the event of an unplanned Outage, a Contingency or threatened or actual System Emergency, all Energy Bids associated with Spinning and Non-Spinning Reserve may be included in the merit order stack. In the event of Inter-Zonal Congestion, separate merit order stacks will be created for each Zone. The information in the merit order stack shall be provided to the real-time dispatcher through the RTD Software. Where, in any Settlement Interval, the highest decremental Energy Bid in the merit order stack is higher than the lowest incremental Energy Bid, the RTD Software will eliminate the Price Overlap by actually dispatching for all those incremental and decremental bids which fall within the overlap.

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

34.1.2.3.3 Use of the Merit Order Stack.

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

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

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

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

(d) recovering Operating Reserves utilized in real time;

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

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

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

Scheduling Coordinators for resources that have been awarded or self-provide Regulation Up, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity must submit a Supplemental Energy bid for at least all the awarded or self-provided Ancillary Services capacity. To the extent a Supplemental Energy bid is not so submitted for a gas-fired resource, the ISO shall calculate a Supplemental Energy bid in accordance with Section 40.10.1 and insert that bid into the real-time Imbalance Energy market. To the extent a Supplemental Energy bid is not so submitted for a non-gas-fired resource, the ISO shall insert a bid of $0/MWh into the real-time Imbalance Energy market.

34.2 Supplemental Energy Bids.

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

34.2.1 Identification of Supplemental Energy Bids.

The upper portion of a Scheduling Coordinator's Energy Bid for a resource providing Spinning, Non-Spinning, or Replacement Reserves that corresponds to the resource's available capacity up to the highest operating limit, shall be allocated to any awarded or self-provided Ancillary Services in the following order from higher to lower capacity: a) Regulation Up; b) Spinning Reserve; c) Non-Spinning Reserve; and d) Replacement Reserve. For resources providing Regulation Up, the upper regulating limit shall be used if it is lower than the highest operating limit. The remaining portion of the Energy Bid, if there is any, shall constitute Supplemental Energy.

34.2.1.1 Timing of Supplemental Energy Bids.

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

34.2.1.1A Form of Supplemental Energy Bid Information.

Supplemental Energy bids must include the following information:

34.2.1.2 Generation Section of Energy Bid Data.

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

(a) Scheduling Coordinator's ID code;

(b) name of Generating Unit;

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

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

(e) Generating Unit startup time function in minutes;

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

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

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

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

34.2.1.3 Demand Section of Energy Bid Data.

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

(a) Scheduling Coordinator's ID code;

(b) name of Demand;

(c) Demand shutdown time in minutes;

(d) Demand shutdown cost in $/start;

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

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

34.2.1.4 External Import Section of Energy Bid Data.

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

(a) Scheduling Coordinator's ID code;

(b) name of Scheduling Point;

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

(d) external Control Area ID;

(e) Schedule ID (NERC ID number);

(f) complete WECC tag;

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

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

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

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

(k) interchange ID code;

(l) external Control Area ID;

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

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

(o) the contract reference number, if applicable.

34.2.1.4A Format of Energy Bids.

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

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

34.2.1.5 Schedule Confirmation.

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

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

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

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

34.2.1.6 Confirm Interchange Transaction Schedules (ITSs).

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

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

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

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

34.3 Real-Time Dispatch.

The ISO, using RTD Software, shall economically Dispatch each Generating Unit, Curtailable Demand, System Unit, Interconnection schedule or System Resource that is effective to: (i) meet Imbalance Energy requirements and eliminate any Price Overlap in real time, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.3.0.3, and (ii) relieve Congestion, if necessary, to ensure System Reliability and to maintain Applicable Reliability Criteria. The ISO shall determine that additional output is needed if the current output levels of the Regulation Generating Units, System Units, and System Resources deviate from their preferred operating points by more than a specified threshold (to be determined by the ISO), or to meet the projected Imbalance Energy requirements for the next Dispatch Interval. The ISO shall employ a multi-interval constrained optimization methodology (RTD Software) to calculate an optimal dispatch for each Dispatch Interval within a time horizon that shall extend to the end of the next hour. The ISO shall Dispatch resources that have submitted Energy Bids over the time horizon to meet forecasted Imbalance Energy requirements minimizing the Imbalance Energy procurement cost over the entire time horizon, subject to resource and transmission system constraints. However, Dispatch Instructions shall be issued for the next Dispatch Interval only. The ISO also shall instruct resources to start up or shut down over the time horizon based on their submitted and validated Start-Up Fuel Costs, Minimum Load Costs and Energy Bids. These resources shall receive binding start-up or shut-down pre-dispatch instructions as required by their startup time. The ISO shall only start resources that can start within the time horizon. The ISO may shut down resources that do not need to be on-line if constraints within the time horizon permit. However, resources providing Regulation or Spinning Reserve shall not be shut down. On-line resources providing Non-Spinning or Replacement Reserve shall also not be eligible for shutdown, unless their minimum down time does not exceed 10 minutes.

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

34.3.0.1.1 Overview.

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

34.3.0.1.2 Utilization of the Energy Bids.

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

(a) satisfying needs for Imbalance Energy;

(b) mitigating Inter-Zonal Congestion;

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

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

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

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

34.3.0.2 General Principles.

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

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

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

Interval and return the Regulation Generating Units, System Units, Dispatchable Interconnection schedules, and System Resources to their preferred operating points to restore their full regulating margin;

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

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

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

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

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

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

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

(j) The ISO will pre-dispatch Energy Bids from System Resources, subject to Hourly Pre-Dispatch as indicated in Section 34.2.1.1A, prior to the beginning of each hour consistent with applicable WECC interchange scheduling practices, assuring that any Price Overlap between such decremental and incremental Energy Bids will be eliminated. Such bids will be settled pursuant to Section 11.2.4.1.1.2.

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

34.3.0.3 Ancillary Services Dispatch.

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

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

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

34.3.0.3.2 Dispatch of Self-Provided Ancillary Services.

Where a Scheduling Coordinator has chosen to self-provide the whole of the additional Operating Reserve required to cover any Interruptible Imports which it has scheduled and has identified specific Generating Units, Loads, System Units or System Resources as the providers of the additional Operating Reserve concerned, the ISO shall Dispatch only the designated Generating Units, Loads, System Units or

System Resources in the event of the ISO being notified that the Interruptible Import is being curtailed. For all other Ancillary Services which are being self-provided the Energy Bid shall be used to determine the Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.3.0.3.

34.3.0.3.3 Ancillary Services Requirements for Real Time Dispatch.

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

34.3.0.3.3.1 Regulation.

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

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

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

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

34.3.0.3.3.2 Operating Reserve.

(a) Spinning Reserve:

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

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

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

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

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

(b) Non-Spinning Reserve:

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

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

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

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

34.3.0.3.3.3 Replacement Reserve.

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

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

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

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

34.3.0.3.3.4 Replacement of Operating Reserve.

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

(b) if pre-arranged Operating Reserve is used to meet balancing Energy requirements, the ISO may replace such Operating Reserve by Dispatch of additional balancing Energy available from Supplemental Energy bids;

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

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

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

34.3.0.3.3.5 Voltage Support.

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

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

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

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

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

34.3.1 Resource Constraints.

The RTD Software shall enforce the following resource physical constraints:

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

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

(c) Operational ramp rates and start-up times. The submitted operational ramp rate as provided for in Section 30.4.6 shall be used for all Dispatch Instructions. Each Energy Bid shall be Dispatched only up to the amount of Imbalance Energy that can be provided within the Dispatch Interval based on the applicable operational ramp rate. The Dispatch Instruction shall consider the relevant start-up time as provided for in Section 30.4.6, if the resource is off-line, the relevant ramp rate function, and any prior commitments such as schedule changes across hours and previous Dispatch Instructions. The start-up time shall be determined from the start-up time function and when the resource was last shut down. The start-up time shall not apply if the corresponding resource is on-line or expected to start.

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

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

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

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

34.3.2 Transmission System Constraints.

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

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

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

34.3.2.1 Inter-Zonal Congestion.

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

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

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

34.3.2.3 Selection of Generating Unit to Reduce Generation.

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

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

Real-time Dispatch Instructions shall be issued for each Dispatch Interval as needed to prescribe the ramp between a resource's Final Hour-Ahead Schedule in one hour to its Final Hour-Ahead Schedule in the immediately succeeding operating hour. Such Dispatch Instructions shall be based on the lesser of: (1) the applicable operational ramp rate as provided for in Section 30.4.6 and (2) the ramp rate associated with the Standard Ramp. The Dispatch Instructions for ramping of Generating Units without real-time Energy Bids in both operating hours shall begin 10 minutes prior to the start of each operating hour and shall end no sooner than 10 minutes after and no later than 50 minutes after the start of each operating hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2.

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

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

34.3.3 Inter-Zonal Congestion.

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

34.3.4 Intra-Zonal Congestion.

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

34.3.5 Recovery of Operating Reserve.

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

Any additional real-time Operating Reserve needs may be met through unloaded capacity from RMR resources.

34.3.6 Dispatch Information and Instructions.

34.3.6.1 Dispatch Information To Be Supplied to the ISO.

34.3.6.2 Dispatch Information To Be Supplied by Scheduling Coordinator

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

34.3.6.3 Dispatch Information To Be Supplied by UDCs.

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

34.3.6.4 Dispatch Information To Be Supplied by PTOs.

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

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

34.3.6.6 Dispatch Information To Be Supplied by Control Area Operators.

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

Coordinator.

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

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

34.3.7 All Dispatch Instructions except those for the Dispatch of Regulation (which will be communicated by direct digital control signals to Generating Units and, for System Resources, through dedicated communication links which satisfy the ISO's standards for external imports of Regulation) will be communicated electronically, except that, at the ISO's discretion, Dispatch Instructions may be communicated by telephone, or fax. Except in the case of deteriorating system conditions or emergency, and except for instructions for the Dispatch of Regulation, the ISO will send all Dispatch Instructions to the Scheduling Coordinator for the Generating Unit, System Unit, Load or System Resource, which it wishes to Dispatch. The recipient Scheduling Coordinator shall ensure that the Dispatch Instruction is communicated immediately to the operator of the Generating Unit, System Unit, external import of System Resources or Load concerned. If the ISO considers that there has been a failure at a particular point in time or inadequate response over a particular period of time by the Generating Units to the Dispatch Instruction, the ISO will notify the relevant Scheduling Coordinator. The ISO may, with the prior permission of the Scheduling Coordinator concerned, communicate with and give Dispatch Instructions to the operators of Generating Units, System Units, external imports of System Resources and Loads directly without having to communicate through their appointed Scheduling Coordinator. The ISO shall record the communications between the ISO and Scheduling Coordinators relating to Dispatch Instructions in a manner that permits auditing of the Dispatch Instructions, and of the response of Generating Units, System Units, external imports of System Resources and Loads to Dispatch Instructions. In situations of deteriorating system conditions or emergency, the ISO reserves the right to communicate directly with the Generator(s) as required to ensure System Reliability. The recipient of a Dispatch Instruction shall confirm the Dispatch Instruction. Dispatch Instructions communicated by the ISO either electronically or by fax shall be confirmed electronically in accordance with ISO procedures. Dispatch instructions communicated verbally shall be confirmed by repeating the Dispatch instructions to the ISO.

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

34.4 Notification of Non-Compliance With A Dispatch Instruction.

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

34.5 Dispatch Instructions for Generating Units and Curtailable Demand.

The ISO may issue Dispatch Instructions covering:

(a) Ancillary Services;

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

(i) Congestion Management;

(ii) provision of Imbalance Energy; or

(iii) replacement of an Ancillary Service;

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

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

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

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

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

34.6 Response Required by Generators to ISO Dispatch Instructions.

Generators must:

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

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

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

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

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

34.7 Qualifying Facilities.

Where a Qualifying Facility (“QF”) has entered into an agreement with a PTO before March 31, 1997 for the supply of Energy to the PTO (an “Existing Agreement”), the ISO 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.

34.8 Failure to Conform to Dispatch Instructions.

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

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

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

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

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

34.9 Pricing Imbalance Energy.

34.9.1 General Principles.

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

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

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

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

34.9.2 Determining Ex Post Prices.

34.9.2.1 Dispatch Interval Ex Post Prices.

34.9.2.2 Computation.

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

34.9.2.3 Eligibility.

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

34.9.2.4 Hourly Ex Post Price.

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

34.9.2.5 Price for Uninstructed Deviations for Participating Intermittent Resources.

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

35 [Not Used]

36 FIRM TRANSMISSION RIGHTS.

36.1 General.

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

36.2 Characteristics of Firm Transmission Rights.

36.2.1 Each FTR shall be defined by a transmission path from an originating Zone to a contiguous receiving Zone. Each FTR shall entitle the FTR Holder to a share of Usage Charges attributable to Inter-Zonal Congestion for transfers on that path from the designated originating Zone to the designated receiving Zone in accordance with Section 36.6. An FTR is a right in one direction only. An FTR Holder shall not be entitled to share in (i) Usage Charges attributable to Inter-Zonal Congestion from the designated receiving Zone to the designated originating Zone; or (ii) Usage Charges payable in accordance with Section 27.1.2.1.5.1 to a Scheduling Coordinator that counter-schedules from the designated originating Zone to the designated receiving Zone.

36.2.2 The ISO Governing Board shall, from time to time, approve the amount of FTRs to be auctioned for each FTR Market and the ISO shall publish this information on the ISO Home Page at least thirty (30) days prior to the auction. The ISO may issue FTRs in one or more auctions in any year so long as the total FTRs for any interface do not exceed the maximum amount permitted in Section 36.3.

36.2.2.1 Should the ISO create additional Zones or otherwise change the ISO's defined Inter-Zonal Interface, and if such changes would affect outstanding FTRs, such changes will not take effect prior to the expiration date of any such outstanding FTRs. The ISO shall also publish an announcement of any such pending changes on the ISO Home Page and WEnet at least thirty (30) days prior to the applicable FTR auction.

36.2.2.2 Any additional FTRs auctioned as a result of changes in the ISO's defined Inter-Zonal Interfaces shall not affect the rights associated with existing FTRs.

36.2.3 Each FTR shall be issued in the denomination of 1 MW. The annual release of FTRs shall start with the hour beginning at 12:00 a.m., on April 1 and end with the hour beginning at 11:00 p.m., on March 31 of the following year. An FTR shall not afford the FTR Holder any right to share in Usage Charges attributable to Inter-Zonal Congestion occurring in any hour before or after the term of the FTR.

36.2.4 The portion of the Usage Charges to which the FTR Holder is entitled shall be determined in accordance with Section 36.6.

36.2.5 FTR Holders shall be entitled to priority in the scheduling of Energy in the Day-Ahead Market as specified in Section 36.7.

36.2.6 Any entity, with the exception of the ISO, shall be eligible to acquire FTRs by participating in the ISO's auction of FTRs, as described in Section 36.4, or by purchasing FTRs in secondary markets. To participate in the ISO's auction of FTRs, an entity must either be a certified Scheduling Coordinator or have met financial requirements equivalent to the financial certification criteria required of all Scheduling

Coordinators. An entity may not acquire FTRs with a total value that exceeds the financial security proved by that entity to the ISO. In addition, an FTR Bidder must have, or have access to, the necessary technical equipment to participate in the electronic auction.

36.2.7 All entities which acquire FTRs by participating in the ISO's auction of FTRs, as described in Section 36.4, directly from the ISO pursuant to Section 36.4.3, or by purchasing FTRs in secondary markets, must register as an FTR Holder with the ISO. To complete this registration, the FTR Holder must notify the ISO, through the form specified for that purpose by the ISO, of all Affiliates of the FTR Holder that are themselves FTR Holders or Market Participants. The requirement that an FTR Holder notify the ISO of all Affiliates that are FTR Holders or Market Participants is continuing for as long as the FTR Holder owns FTRs, and FTR Holders must provide the ISO with supplemental notification concerning FTR Holders and/or Market Participants that become affiliated with the FTR Holder or Affiliates that subsequently become FTR Holders or Market Participants in order to satisfy this requirement.

36.3 Maximum Number of Firm Transmission Rights.

36.3.1 On each Inter-Zonal Interface and direction combination for which FTRs are issued, the ISO shall issue a number of FTRs that is less than or equal to the difference between:

(i) The WECC approved path rating of the interface in the direction from the originating Zone to the receiving Zone or, if the interface has not received a WECC approved rating, a rating determined by a methodology that is consistent with the WECC’s rating methodology; and

(ii) The portion of the transfer capability of the interface available for transmission scheduling under Existing Contracts as Existing Rights.

and ensures the ISO's ability to honor all of its FTRs simultaneously under normal operating conditions.

36.4 Issuance of Firm Transmission Rights by the ISO.

36.4.1 The ISO shall make FTRs available by conducting an annual primary auction of FTRs, commencing approximately two months before the beginning of the term of the FTRs; provided; however that for the initial FTR release, the primary auction shall be as determined by the ISO Governing Board. The auction of FTRs shall be a simultaneous multi-round, clearing price auction conducted separately and independently, as set forth in Section 36.4.2, for each FTR Market. In addition, if the ISO Governing Board decides to make available, between annual auctions, FTRs in addition to those that were purchased in the last annual auction, the ISO may conduct additional auctions of such FTRs in accordance with Section 36.4.2. The term of such FTRs shall only be for the remaining duration of the FTR term defined for the primary auction applicable to the year during which they were issued.

36.4.2 The ISO shall conduct the auction of FTRs through the following procedures:

36.4.2.1 At least thirty (30) days prior to the scheduled start of the auction, the ISO shall post on the ISO Home Page the following information:

(i) the number of FTRs to be issued for each FTR Market;

(ii) the starting bid price at which FTRs will be made available in each FTR Market in the first round of the auction, which price will be set in each FTR Market at a level equal to the greater of (a) $100 per MW-year; (b) twenty (20) percent of the ratio of the net Usage Charges collected by the ISO with respect to that FTR Market in the most recent twelve-month period for which data are available to the total MW-years of Energy scheduled over the Inter-Zonal Interface in the relevant direction during that period; or (c) twenty (20) percent of the ration of the net Grid Operation Charges (for new Inter-Zonal Interfaces that previously were transmission paths within a Zone) collected by the ISO in the most recent twelve-month period for which data are available to the total MW-years of Energy scheduled over the transmission paths in the relevant direction during that period, provided that, if data are available for only a portion of the twelve-month period, such data shall be used on annualized basis;

(iii) the formula through which the ISO will determine how much to adjust the price of FTRs in each FTR Market for subsequent rounds of the auction, including the initial coefficients to be used in the formula and the range over which the coefficients may be adjusted in accordance with Section 36.4.2.3;

(iv) the date and time prior to the commencement of the auction by which each entity desiring to bid on FTRs must have satisfied the necessary financial requirements as outlined in Section 36.2.6;

(v) the specifications for the technical equipment necessary to participate in the auction, which will be conducted electronically, the date and time by which bids must be submitted in the first round of the auction, which shall be the same for all FTR Markets, and the form and format in which bids must be submitted; and

(vi) a schedule for the conduct of subsequent rounds of the auction, including the interval between rounds of the auction and the anticipated duration of the auction.

36.4.2.2 On or before the date specified in Section 36.4.2.1(v), any entity desiring to obtain FTRs in the ISO's auction must submit, via equipment satisfying the technical requirements specified in accordance with Section 36.4.2.1(v), a bid for each FTR Market in which the entity desires to participate, specifying the number of FTRs the entity is willing to purchase at the price specified in Section 36.4.2.1(ii). All individual bids will remain confidential throughout all rounds of the auction in each FTR Market. Once submitted to the ISO, a bid for FTRs in any round of an auction may not be cancelled or rescinded by the FTR Bidder. The ISO shall announce simultaneously to all FTR Bidders the total quantity of FTRs for which valid bids are submitted for each FTR Market.

36.4.2.3 In each round of the auction following the first round, the ISO will increase the price at which FTRs are made available in each FTR Market in accordance with the formula posted in accordance with Section 36.4.2.1(iii), or in accordance with any adjustment to the coefficients in that formula that is announced by the ISO to the FTR Bidders at least one round in advance of the round for which the adjustment is made. Price increases need not be uniform for all FTR Markets. In the case of an FTR Market in which the demand for FTRs in the preceding round is less than or equal to the quantity of FTRs being made available, the price shall not increase and the auction for that FTR Market shall close. After each round of the auction, the ISO shall announce simultaneously to all FTR Bidders the total quantity of

FTRs for which valid bids were submitted in each FTR Market, whether the auction for each FTR Market is closed, and, the revised prices for the following round of the auctions that remain open. Within the timeframe set by the ISO in accordance with Section 36.4.2.1(vi), each FTR Bidder may submit bids for the quantity of FTRs it desires to purchase in each FTR Market at the revised price, provided that an FTR Bidder may not bid for a number of FTRs in an FTR Market that exceeds the total number of FTRs in that FTR Market for which that entity submitted bids in the preceding round of the auction. The ISO shall conduct subsequent rounds of the auction in each FTR Market until the demand for FTRs in the FTR Market is less than or equal to the quantity of FTRs being made available, at which point the auction shall be closed in that FTR Market.

36.4.2.4 Subject to Section 36.4.2.5, each successful FTR Bidder shall receive a number of FTRs in each FTR Market equal to the number of FTRs for which it bid in the last round of the auction for that FTR Market.

36.4.2.5 For any FTR Market in which, when the auction has closed, the number of FTRs being made available exceeds the demand for FTRs in that FTR Market in the last round of the auction, each FTR Bidder shall be awarded a number of FTRs determined in accordance with the following formula, provided that, if the number of FTRs that would be awarded under the formula to an FTR Bidder that did not submit a bid in the last round of the auction is less than five percent (5%) of the initial bid submitted by that FTR Bidder for the FTR Market, that FTR Bidder shall have the option of declining the award of FTRs resulting from the formula:

N = B + [(R / TR) * D]

where

N = The total number of FTRs awarded to an FTR Bidder for an FTR Market, which shall be in whole MWs and shall not exceed the number of FTRs for which that FTR Bidder bid in the round preceding the final round of the auction;

B = The number of FTRs for which an FTR Bidder bid in the final round of the auction for the FTR Market in accordance with Section 36.4.2.4 (or zero, if the FTR Bidder did not bid in that round);

R = The difference between the number of FTRs for which the FTR Bidder bid in the round preceding the final round of the auction and B, but not less than zero;

TR = The total of the demand reductions (R) for all FTR Bidders that submitted bids in the last round of the auction (treating the failure by an FTR Bidder to submit a bid as a bid of zero); and

D = The difference between the total demand for FTRs in the final round of the auction and the quantity of FTRs being made available for the FTR Market.

36.4.2.6 The price of FTRs in an FTR Market shall be the last price at which the demand for FTRs in the FTR Market exceeded or equaled the quantity of FTRs being made available pursuant to Section 36.4.2.1(i), except that, if the demand for FTRs in an FTR Market in the first round of the auction was less than the quantity of FTRs being made available for that FTR Market, the price of FTRs in that FTR Market shall be the first round price and each FTR Bidder in that FTR Market will receive a number of FTRs equal to the quantity of bids they submitted in the first round. Any remaining FTRs in that FTR Market will not be awarded in that auction.

36.4.2.7 Each FTR Bidder shall pay the ISO an amount equal to the sum, for all FTR Markets, of the products of the FTR price in each FTR Market (determined in accordance with Section 36.4.2.6) and the total quantity of FTRs awarded to that FTR Bidder in that FTR Market (determined in accordance with Section 36.4.2.4 or Section 36.4.2.5, as applicable). FTR Bidders shall pay the amount determined in accordance with the foregoing sentence within ten (10) Business Days of receiving an invoice from the ISO by making payment to the ISO Clearing Account in accordance with Section 11.10. If the FTR Bidder fails to make timely payment of the full amount due, the ISO may enforce any guarantee, letter of credit or other credit support provided by the defaulting FTR Bidder in accordance with Section 36.2.6 and, if the ISO is required to institute proceedings to collect any unpaid amount, the defaulting FTR Bidder shall pay Interest on the unpaid amount for the period from the Payment Date until the date on which payment is remitted to the ISO Clearing Account.

36.4.2.8 The ISO shall post on the ISO Home Page the prices at which FTRs are sold in each FTR Market through the primary auction.

36.4.3 For the ten-year transition period described in Section 4 of Schedule 3 to Appendix F, a New Participating TO that has an obligation to serve Load shall receive FTRs for Inter-Zonal Interfaces to which the transmission facilities and Converted Rights for Inter-Zonal Interfaces that the New Participating TO turns over to the ISO's Operational Control give it transmission rights, provided such transmission facilities are Existing High Voltage Facilities. The amount of FTRs will be determined when the Transmission Control Agreement is executed and shall be commensurate with the transmission capacity the New Participating TO is turning over to ISO Operational Control. The ISO will submit to FERC in the transmittal letter for the amendment to the Transmission Control Agreement regarding each New Participating TO the amount of FTRs allocated to such New Participating TO. The amount of FTRs that has been determined will not be effective until after FERC issues an order concerning the amendment required by this section. No additional FTRs will be issued to New Participating TOs for building High Voltage Transmission Facilities after they become Participating TOs. FTRs issued in accordance with this section shall entitle the FTR Holder to receive Usage Charge revenues and to priority in the scheduling of Energy in the Day-Ahead Market in accordance with the provisions of the ISO Tariff. FTRs associated with Converted Rights shall terminate on the earlier of termination of the Existing Contract or the end of the ten-year transition period.

36.5 Distribution of Auction Revenues Received by the ISO for Firm Transmission Rights.

36.5.1 For each Inter-Zonal Interface and direction for which an FTR is defined, the total proceeds received by the ISO through the auction described in Section 36.4 shall be allocated and paid by the ISO to the Participating TO that is entitled in accordance with Section 27.1.2.1.6 to receive Usage Charge revenues with respect to the corresponding Inter-Zonal Interface. Each Participating TO shall credit its FTR auction proceeds against its high voltage TRBA if the FTR is for a High Voltage Transmission Facility or against its low voltage TRBA if the FTR is a for a Low Voltage Transmission Facility.

36.5.2 In the event the transmission facilities or rights making up an Inter-Zonal Interface with respect to which FTRs are defined are owned by more than one Participating TO, the proceeds of the auction of such FTRs shall be allocated to those Participating TOs who auction FTRs in proportion to the FTRs associated with their Inter-Zonal Interface as of the date of the FTR auction compared to all FTRs auctioned for such Inter-Zonal Interface.

36.5.3 In the event the transmission facilities or rights making up an Inter-Zonal Interface with respect to which FTRs are defined have been upgraded resulting in increased transmission capacity on the Inter-Zonal Interface, and the costs of construction and operation were paid for by a Project Sponsor pursuant to Section 24.7.1 and were not included in the ISO's transmission Access Charge or a reimbursement or direct payment from a Participating TO, the proceeds of the auction of such FTRs shall be allocated to the Project Sponsors according to the allocated shares determined as set forth in Section 24.7.3(d).

36.6 Distribution of Usage Charges to FTR Holders.

36.6.1 The FTR Holder shall be entitled to receive from the ISO a portion of the total Congestion revenues related to Inter-Zonal Congestion calculated by the ISO in the Day-Ahead Market and collected by the ISO with respect to the Inter-Zonal Interface and direction combination for which the FTR was defined. This portion equals the Usage Charge calculated by the ISO in the Day-Ahead Market for the transfer of 1 MW from the originating Zone to the receiving Zone during each hour in which Usage Charges apply, multiplied by the number of FTRs owned by that FTR Holder, subject to adjustment in accordance with Section 36.6.3.

36.6.2 In addition, an FTR Holder shall be entitled to receive a portion of the additional net Usage Charges related to Inter-Zonal Congestion calculated by the ISO in the Hour-Ahead Market and collected by the ISO with respect to the Inter-Zonal Interface and direction combination for which the FTR was defined. The FTR Holder shall receive a portion of the net Usage Charges in the Hour-Ahead Market proportionate to the share of the Usage Charges it received in the Day-Ahead Market in accordance with Section 36.6.1.

36.6.3 When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is less than its scheduling capacity, determined in accordance with Section 36.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be reduced until and unless the entitlements of Participating TOs associated with that FTR Market to Usage Charge revenues in accordance with Section 27.1.2.1.6 have been reduced to zero. In that event, the financial entitlements associated with the corresponding FTRs shall be multiplied by a factor equal to the amount of scheduling capability available to holders of the remaining FTRs divided by the number of such FTRs. When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is greater than its scheduling capacity, determined in accordance with Section 36.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be increased.

36.6.4 When the Congestion Usage Charges calculated and collected by the ISO from the Hour-Ahead Market with respect to transfers across an Inter-Zonal Interface in a particular direction result in a net obligation to the ISO, in the circumstances described in Section 27.1.2.1.7, the provisions of this Section 9.6 shall continue to apply, and FTR Holders shall be required to pay the ISO these amounts.

36.6.5 The ISO will calculate the Congestion Usage Charge revenues to be credited or debited to the account of each FTR Holder on an hourly basis. Such calculation will identify the Inter-Zonal Interface and direction to which each credit or debit applies.

36.7 Scheduling Priority of FTR Holders.

36.7.1 FTRs will not affect the ISO's dispatch and operation of the ISO Controlled Grid except that each FTR Holder will have a priority, as described in this Section 36.7, for the scheduling of Energy in the Day-Ahead Market when an Inter-Zonal Interface experiences Inter-Zonal Congestion in the direction for which its FTR is defined. Any FTRs not used in Preferred Schedules in the Day-Ahead Market for any hour have no scheduling priority for that hour in the Trading Day. FTR Holders shall have no scheduling priority in the Hour-Ahead Market or in real-time operations.

36.7.2 When Inter-Zonal Congestion is experienced or projected to be experienced in the Day-Ahead Market, the ISO shall first attempt to relieve the Inter-Zonal Congestion using Adjustment Bids submitted by Scheduling Coordinators in accordance with Section 27.1.1.4.

36.7.2.1 If the ISO is unable to relieve the Day-Ahead Inter-Zonal Congestion using Adjustment Bids, then the ISO will allocate Day-Ahead inter-zonal transmission capacity first to Schedules of Market Participants that are using Existing Contract rights that have higher scheduling priority than Converted Rights capacity and second to Market Participants who hold FTRs and have indicated to the ISO that they wish to exercise their scheduling priority option. The ISO will allocate any remaining transmission capacity to remaining Market Participants' Schedules pro rata.

36.7.3 When the scheduling capability of an Inter-Zonal Interface is less than or greater than its normal scheduling capability prior to the Day-Ahead Market, as described in Section 36.6.3, the priority scheduling rights of FTR Holders, as described in Section 36.7.2, shall remain constant (in MWs) to the extent that the total scheduling rights of FTR Holders do not exceed the total Interface scheduling capability of the associated Inter-Zonal Interface after adjustments have been made for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights. If the total Interface scheduling capability, adjusted for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights, is less than the total of all scheduling capability represented by FTR Holders who have chosen to exercise the FTR scheduling priority option, scheduling capability shall be allocated to FTR Holders pro rata.

36.7.4 The scheduling priority of FTR Holders:

(i) Shall not apply in the Hour-Ahead Market or in real-time dispatch and operation of the ISO Controlled Grid;

(ii) Shall not apply to any transfer of Energy other than a transfer across the Inter-Zonal Interface in the direction for which the FTR was defined during the hour or hours during which the circumstances described in Section 36.7.2.1 apply; and

(iii) Shall not be transferable, except in connection with a transfer of the FTR that is registered with the ISO, as described in Section 36.8.

36.8 Assignment of Firm Transmission Rights.

36.8.1 An FTR may be assigned, sold, or otherwise transferred by the FTR Holder to any entity eligible to be an FTR Holder in full MW increments, either for the entire term of the FTR or for any portion of that term providing, however, that any such transfer shall be in full hour increments that correspond to the FTR issued to the FTR Holder. All FTRs that are so assigned, sold, or otherwise transferred by the FTR Holder are subject to the terms and conditions for FTRs approved by FERC and set forth in the ISO Tariff. Both the FTR Holder of record and the entity to which the FTRs have been transferred shall register the transfer of the FTR with the ISO by notifying the ISO through the form specified for that purpose by the ISO, and within the number of Business Days following the transfer published by the ISO on the ISO Home Page and WEnet but no later than such time as the ISO shall specify before the deadline applicable to scheduling Energy in the Day-Ahead Market, of (i) the identity of the FTR Holder of record; (ii) the identity of the entity to which the FTRs have been transferred; (iii) the quantity and identification numbers of the FTRs being transferred; (iv) the portion of the term of the FTR for which they are transferred; (v) the price at which the FTRs are being transferred; and (vi) whether the transfer of FTRs is subject to any conditions. The entity to which the FTRs have been transferred must also notify the ISO of all entities with which the transferee is affiliated that are FTR Holders or Market Participants as defined in the ISO Tariff, pursuant to Section 36.2.7. After the ISO receives such notices, the transferee shall be considered the FTR Holder of record with respect to the portion of the term of the FTR that is transferred. In order to use the Scheduling Priority of an FTR, pursuant to Section 36.7, an FTR must be registered with the ISO.

36.8.2 The ISO shall publish on the ISO Home Page such information concerning the concentration of ownership of FTRs in each FTR Market as determined by the ISO Governing Board from time to time.

36.8.3 To facilitate the operation of secondary markets in FTRs, the ISO shall post on WEnet and the ISO Home Page: (i) the identity of entities that hold FTRs that have been registered with the ISO, together with the quantity of FTRs held by such entities in each FTR Market and the path rating of the interface; and (ii) the name and a contact telephone number or telecopy number of any entity that operates a secondary market in FTRs and that requests the ISO to post such information. The ISO shall also post the prices at which FTRs are transferred through secondary market transactions and shall indicate whether such transfers are conditional.

37 ENFORCEMENT PROTOCOL.

37.1 Objectives, Definitions, and Scope.

37.1.1 Purpose.

This Section sets forth the guiding principles for participation in the markets administered by the California Independent System Operator. The specified Rules of Conduct are intended to provide fair notice to Market Participants of the conduct expected of them, to provide an environment in which all parties may participate on a fair and equal basis, to redress instances of gaming and other instances of anticompetitive behavior, and thereby to foster confidence of Market Participants, ratepayers and the general public in the proper functioning of the ISO markets.

37.1.2 Objectives.

The objectives of this ISO Tariff are to:

(a) Provide clear Rules of Conduct specifying the behavior expected of Market Participants; and

(b) Establish in advance the Sanctions and other potential consequences for violation of the specified Rules of Conduct.

37.1.3 Application of Other Remedies.

The activities and remedies authorized under this Section 37 are in addition to any other actions or relief that may be available to the ISO elsewhere in the ISO Tariff or under law, regulation or order. Nothing in this Section 37 limits or should be construed to limit the right of the ISO to take action or seek relief otherwise available to it, and such action or relief may be pursued in lieu of or in addition to the action or relief specified in this Section 37.

37.1.4 FERC Authority.

In addition to any authority afforded Market Monitoring Unit in this Section 37, FERC shall have the authority to assess the sanctions, and otherwise to enforce the rules as set forth and described in this Section 37. FERC shall have authority to remedy a violation under this Section 37 from the date of the violation. Nothing in this Section 37 shall be deemed to be a limitation or condition on the authority of FERC or other entities under current law or regulation.

37.1.5 Administration.

The Marketing Monitor Unit will administer the Rules of Conduct specified herein, except for Section 37.7, which shall be administered by FERC, and except as provided in Section 37.2.5 and Section 37.4.4 . Nothing in this ISO Tariff limits or should be construed to limit the ability of components of the ISO organization other than the Market Monitoring Unit to analyse data and refer matters to the Market Monitoring Unit for enforcement.

37.2 Comply with Operating Orders.

37.2.1 Compliance with Orders Generally.

37.2.1.1 Expected Conduct.

Market Participants must comply with operating orders issued by the ISO as authorized under the ISO Tariff. For purposes of enforcement under this Section 37.2, an operating order shall be an order(s) from the ISO directing a Market Participant to undertake, a single, clearly specified action (e.g., the operation of a specific device, or change in status of a particular Generating Unit) that is feasible and intended to resolve a specific operating condition. A Market Participant's failure to obey an operating order containing multiple instructions to address a specific operating condition will result in a single violation of Section 37.2. If some limitation prevents the Market Participant from fulfilling the action requested by the ISO, then the Market Participant must promptly and directly communicate the nature of any such limitation to the ISO. Compliance with ISO operating orders requires a good faith effort to achieve full performance as soon as is reasonably practicable in accordance with Good Utility Practice.

37.2.1.2 Sanctions.

The Sanction for a violation of this Section shall be the greater of the quantity of Energy non-performance multiplied by the applicable Hourly Ex Post Price or the following: for the first violation in a rolling twelve (12) month period, $5,000; for the second and subsequent violations in a rolling twelve (12) month period, $ 10,000. Sanctions under Section 37.2.1 will not be greater than $10,000 per violation and will be subject to the limitation stated in Section 37.2.6. If a quantity of energy cannot be objectively determined, then the financial sanctions specified above will apply. A Market Participant may incur Sanctions for more than one violation per day.

37.2.2 Failure to Curtail Load.

37.2.2.1 Expected Conduct.

A UDC or MSS Operator shall promptly comply with any ISO operating order to curtail interruptible or firm load issued pursuant to the ISO's authority under Section 7.4.11.3 of the ISO Tariff.

37.2.2.2 Sanctions.

The Sanction for non-compliance with an operating order to curtail load will be $10,000 for each violation.

37.2.3 Operations & Maintenance Practices.

37.2.3.1 Expected Conduct.

Market Participants shall undertake such operating and maintenance practices as necessary to avoid contributing to a major outage or prolonging response time as indicated by Section 7.4.13.3 of the ISO Tariff.

37.2.3.2 Sanctions.

The Sanction for a violation of Section 37.2.3 will be $10,000.

37.2.4 Must-Offer Denials/Revocations.

37.2.4.1 Expected Conduct.

A Market Participant shall start a Generating Unit and have that Generating Unit operating at minimum load within 30 minutes of the time at which a must-offer waiver revocation becomes effective, or report the derate, outage or other event outside the control of the Market Participant that prevents the Generating Unit from being started by such time. Notwithstanding the foregoing, no violation shall occur unless the Market Participant has been provided advance notice of the waiver revocation consistent with the relevant start-up time set forth in the ISO Master File. A Market Participant that fails to perform in accordance with the expected conduct described in this Section 37.2.4.1 shall be subject to Sanction.

37.2.4.2 Sanctions.

The Sanctions for a violation of Section 37.2.4 shall be as follows: for the first violation in a rolling twelve (12) month period, $5,000; for the second and all subsequent violations in a rolling twelve (12) month period, $10,000. A Market Participant is limited to one Sanction per Generating Unit per calendar day.

37.2.5 Enhancements and Exceptions.

Except as otherwise specifically provided, penalty amounts shall be tripled for any violation of Section 37.2.1 through Section 37.2.4 if an ISO System Emergency exists at the time an operating order becomes effective or at any time during the Market Participant's non-performance. Notwithstanding the foregoing, violations of Section 37.2.1 through Section 37.2.4 are subject to penalty under this rule only to the extent that the ISO has issued a separate and distinct non-automated Dispatch Instruction to the Market Participant. Any penalty amount that is tripled under this provision and that would exceed the $10,000 per day penalty limit shall not be levied against a Market Participant until the ISO proposes and the Commission approves such an enhancement. A Market Participant that is subject to an enhanced penalty amount under this Section 37.2.5 may appeal that penalty amount to FERC if the Market Participant believes a mitigating circumstance not covered in Section 37.9.2 exists. The duty of the Market Participant to pay the enhanced penalty amount will be tolled until FERC renders its decision on the appeal.

37.2.6 Per-Day Limitation on Amount of Sanctions.

The amount of Sanctions that any Market Participant will incur for committing two or more violations of Section 37.2.1 through Section 37.2.4 on the same day will be no greater than $10,000 per day.

37.3 Submit Feasible Energy and Ancillary Service Bids and Schedules.

37.3.1 Bidding Generally.

37.3.1.1 Expected Conduct.

Market Participants must bid and schedule Energy and Ancillary Services from resources that are reasonably expected to be available and capable of performing at the levels specified in the bid and/or schedule, and to remain available and capable of so performing based on all information that is known to the Market Participant or should have been known to the Market Participant at the time of bidding or scheduling.

37.3.1.2 Consequence for Non-Performance.

A Market Participant that fails to perform in accordance with the expected conduct described in Section 37.3.1.1 above shall be subject to having the payment rescinded for any portion of an Ancillary Service that is unavailable.

37.3.2 Exceptions.

Violations of Section 37.3.1 that result in circumstances in which an Uninstructed Deviation Penalty under Section 11.2.4.1.2 of the ISO Tariff may be assessed or for which payments have been eliminated under Section 8.10.2 of the ISO Tariff are not subject to Sanction under this section. The submission of a Schedule that causes, or that the ISO expects to cause Intra-Zonal Congestion shall not, by itself, constitute a violation of Section 37.3.1 unless the Market Participant fails to comply with an obligation under the ISO Tariff to modify Schedules as determined by the ISO to mitigate such congestion or such Schedules violate another element of this Rule.

37.4 Comply with Availability Reporting Requirements.

37.4.1 Reporting Availability.

37.4.1.1 Expected Conduct.

A Market Participant shall notify the ISO Control Center of any Outage reportable pursuant to Section 9.3.10.2.1 of the ISO Tariff of a Generating Unit subject to Section 4.6 of the ISO Tariff within thirty (30) minutes after the Outage is discovered.

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37.4.1.2 Sanctions.

The Sanctions for a violation of Section 37.4.1 shall be as follows: for the first violation in a rolling twelve (12) month period, a warning letter; for the second violation in a rolling twelve (12) month period, $1,000; for the third violation in a rolling twelve (12) month period, $2,000; for the fourth and subsequent violations in a rolling twelve (12) month period, $5,000. A Market Participant shall not be subject to more than one Sanction per Generating Unit per calendar day for violating Section 37.4.1. A “violation” shall mean each failure to report an Outage for a specific Generating Unit as required by Section 9.3.10.2.1 of the ISO Tariff.

37.4.2 Scheduling and Final Approval of Outages.

37.4.2.1 Expected Conduct.

A Market Participant shall not undertake an Outage except as approved by the ISO Outage Coordination Office in accordance with Section 9.3.2, Section 9.3.9, and Section 9.3.6.6 of the ISO Tariff. A Market Participant shall not commence any Outage without obtaining final approval from the ISO Control Center in accordance with Sections 9.3.9 and 9.3.10 of the ISO Tariff.

37.4.2.2 Sanctions.

The Sanctions for a violation of Section 37.4.2 shall be as follows: for the first violation within a rolling twelve (12) month period, $5,000; for subsequent violations within a rolling twelve (12) month period, $10,000. A “violation” shall mean each Outage undertaken for which all required approvals were not obtained.

37.4.3 Explanation of Forced Outages.

37.4.3.1 Expected Conduct.

A Market Participant must provide a detailed explanation of a Forced Outage within two (2) Business Days after the discovery of a Forced Outage as specified in Section 9.3.10.5 of the ISO Tariff. An Operator must promptly provide information requested by the ISO to enable the ISO to review the explanation submitted by the Operator and to prepare a report on the Forced Outage.

37.4.3.2 Sanctions.

The Sanction for failing to provide a timely explanation of Forced Outage shall be $500 per day for each day the explanation is late. The Sanction for failing to provide a timely response to information requested shall be as specified in Section 37.6.1.

37.4.4 Enhancements and Exceptions.

Except as otherwise specifically provided, penalty amounts shall be tripled for any violation of Section 37.4.1 through Section 37.4.3 that occurs during an ISO System Emergency. Violations of the above rules that result in circumstances in which an Uninstructed Deviation Penalty under Section 11.2.4.1.2 of the ISO Tariff may be assessed shall not be subject to Sanction under this Section 37.4. A Market Participant that is subject to an enhanced penalty amount under this Section 37.4.4 may appeal that penalty amount to FERC if the Market Participant believes a mitigating circumstance not covered in Section 37.9.2 exists. The duty of the Market Participant to pay the enhanced penalty amount will be tolled until FERC renders its decision on the appeal.

37.5 Provide Factually Accurate Information.

37.5.1 Accurate Information Generally.

37.5.1.1 Expected Conduct.

All applications, Schedules, reports, and other communications by a Market Participant or agent of a Market Participant to the ISO, including maintenance and outage data, bid data, transaction information, and load and resource information, must be submitted by a responsible company official who is knowledgeable of the facts submitted. The Market Participant shall provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with FERC, FERC-approved market monitors, FERC-approved regional transmission organizations, or FERC-approved independent system operators, or jurisdictional transmission providers, unless the Market Participant exercised due diligence to prevent such occurrences.

37.5.1.2 Sanctions.

The Sanctions for a violation of Section 37.5.1 shall be as follows: for the first violation within a rolling twelve (12) month period, $2,500; for the second violation within a rolling twelve (12) month period), $5,000; subsequent violations within a rolling twelve (12) month period, $10,000.

37.5.2 Inaccurate Meter Data.

37.5.2.1 Expected Conduct.

Market Participants shall provide complete and accurate Settlement Quality Meter Data for each Trade hour and shall correct any errors in such data prior to the issuance of Final Settlement Statements. Failure to provide complete and accurate Settlement Quality Meter Data, as required by Section 10 of the ISO Tariff and that results in an error that is discovered after issuance of Final Settlement Statements, shall be a violation of this rule.

37.5.2.2 Sanctions.

Violations under this Section 37.5.2 shall be subject to Sanction described in Section 37.11.

37.5.2.3 Disposition of Sanction Proceeds.

For purposes of redistributing collected penalties, any amounts collected under this provision shall be applied first to those parties affected by the conduct. Any excess amounts shall be disposed of as set forth in Section 37.9.4.

37.6 Provide Information Required by ISO Tariff.

37.6.1 Required Information Generally.

37.6.1.1 Expected Conduct.

Except as provided below in Section 37.6.4 (Review by FERC), all information that is required to be submitted to the ISO under the ISO Tariff, ISO protocols, or jurisdictional contracts must be submitted in a complete, accurate, and timely manner. Market Participants must comply with requests for information or data by the ISO authorized under the ISO Tariff, including timelines specified in the ISO Tariff for submitting Schedules and other information.

37.6.1.2 Sanctions.

Except as otherwise provided below, in Section 37.6.2 and Section 37.6.3, a violation of this rule is subject to a penalty of $500 for each day that the required information is late.

37.6.2 Investigation Information.

37.6.2.1 Expected Conduct.

Except as provided below in Section 37.6.4 (Review by FERC), Market Participants must submit timely information in response to a written request by the ISO for information reasonably necessary to conduct an investigation authorized by the ISO Tariff.

37.6.2.2 Sanctions.

The Sanction for a violation of Section 37.6.2 shall be as follows: for the first violation in a rolling 12-month period, $1000/day; for the second violation in a rolling 12-month period, $2000/day; for the third and subsequent violations in a rolling 12-month period, $5000/day. For purposes of this subsection, a violation shall be each failure to provide a full response to a written request and the Sanction shall be determined from the date that the response was due until a full response to the request is received.

37.6.3 Audit Materials.

37.6.3.1 Expected Conduct.

Except as provided below in Section 37.6.4 (Review by FERC), Market Participants shall comply with the ISO's audit and/or test procedures, and further shall perform and timely submit an annual self-audit as required under the ISO Tariff.

37.6.3.2 Sanctions.

For failure to submit an annual Scheduling Coordinator Self Audit report, the Sanction shall be $1000/day until such report is received by the ISO. For all other violations of this rule the Sanctions shall be as follows: for the first violation in a rolling 12-month period, $1000/day; for the second violation in a rolling

12-month period, $2000/day; for the third and subsequent violations in a rolling 12-month period, $5000/day. For purposes of this subsection, a “violation” shall be each failure to provide all information required under the audit or test, from the date that the information was due until all required information is received by the ISO.

37.6.4 Review by FERC.

A Market Participant who objects to an information, audit or test obligation that is enforceable under Section 37.6.1, Section 37.6.2 or Section 37.6.3 above shall have the right immediately (and in all events, no later than the due date for the information) to seek review of the obligation with FERC. In the event that such review is sought, the time for submitting the response or other information to the ISO shall be tolled until FERC resolves the issue.

37.7 No Market Manipulation.

37.7.1 Market Manipulation Generally.

37.7.1.1 Expected Conduct.

Actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products are prohibited. Actions or transactions by a Market Participant that are explicitly contemplated in the ISO Tariff or are undertaken at the direction of the ISO are not in violation of this Rule of Conduct.

37.7.1.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.2 Wash Trades.

37.7.2.1 Expected Conduct.

Market Participants shall not engage in pre-arranged offsetting trades of the same product among the same parties, which involve no economic risk and no net change in beneficial ownership (sometimes called "wash trades").

37.7.2.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.3 False Information.

37.7.3.1 Expected Conduct.

A Market Participant shall not engage in transactions predicated on submitting false information to transmission providers or other entities responsible for operation of the transmission grid (such as inaccurate load or generation data; or scheduling non-firm service or products sold as firm), unless the Market Participant exercised due diligence to prevent such occurrences.

37.7.3.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.4 Artificial Congestion.

37.7.4.1 Expected Conduct.

A Market Participant shall not engage in transactions in which it first creates artificial congestion and then purports to relieve such artificial congestion (unless the Market Participant exercised due diligence to prevent such an occurrence).

37.7.4.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.5 Collusion.

37.7.5.1 Expected Conduct.

Market Participants shall not engage in collusion with another party for the purpose of manipulating market prices, market conditions, or market rules for electric energy or electricity products.

37.7.5.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.8 Process for Investigation and Enforcement.

37.8.1 Purpose; Scope.

The provisions of this Section 37.8 set forth the procedures by which the Market Monitoring Unit will independently investigate potential violations of the Rules of Conduct and administer enforcement activities. Except as hereinafter provided, and except as provided in Section 37.2.5 and Section 37.4.4, the provisions of this section apply to the Rules of Conduct set forth in Sections 37.2 through 37.7.

37.8.2 Referrals to FERC.

Section 37.7 shall be enforced by FERC, in accordance with FERC's rules and procedures. The Market Monitoring Unit shall refer to FERC and its staff all matters in which it has formed a reasonable belief that a violation of Section 37.7 may have occurred. Although Sections 37.2 through 37.6 will generally be enforced by the Market Monitoring Unit, the Market Monitoring Unit shall refer to FERC any matter for which the particular circumstances preclude the objective determination of a Rules of Conduct violation, and shall refer to FERC any Sanction that it believes should be modified in accordance with Sections 37.2.5, 37.4.4, or 37.9.1. The time limitation contained in Section 37.10.1 to assess a Sanction under this Protocol shall be determined as of the date that a Sanction is initially assessed by the ISO, excluding the time required for FERC to investigate a potential Rules of Conduct violation and/or determine a Sanction in accordance with this section, Sections 37.2.5, 37.4.4, or 37.9.1.

37.8.3 Investigation.

The Market Monitoring Unit shall conduct a reasonable investigation seeking available facts, data, and other information relevant to the potential Rules of Conduct violation.

37.8.4 Notice.

The Market Monitoring Unit shall provide notice of the investigation in sufficient detail to allow for a meaningful response to the Scheduling Coordinator and, as limited below, to all Market Participants the Scheduling Coordinator represents that are the subject(s) of the investigation. The Market Monitoring Unit shall contact the Market Participant(s) that may be involved, so long as the ISO has sufficient objective information to identify and verify the role of the Market Participant(s) in the potential Rules of

Conduct violation. Such Market Participant(s) will likely have an existing contractual relationship with the ISO (e.g., UDC, MSS, ISO Metered Entity, Participating Transmission Owner, Participating Generator, or Participating Load).

37.8.5 Opportunity to Present Evidence.

The Market Monitoring Unit shall provide an opportunity to the Market Participant(s) that are the subject(s) of the investigation to present any issues of fact or other information relevant to the potential Rules of Conduct violation being investigated. The Market Monitoring Unit shall consider all such information or data presented.

37.8.6 Results of Investigation.

The Market Monitoring Unit shall notify the Market Participant(s) that are the subject(s) of the investigation of the results of the investigation. The Market Participant(s) shall have 30 days to respond to the findings of the Market Monitoring Unit before the Market Monitoring Unit makes a determination of whether a Sanction is required by this ISO Tariff.

37.8.7 Statement of Findings and Conclusions.

Where the investigation results in a Sanction, the Market Monitoring Unit shall state its findings and conclusions in writing, and will make such writing available to the Scheduling Coordinator and, as provided in Section 37.8.4, to the Market Participant(s) that are the subject(s) of the investigation.

37.8.8 Officer Representative.

Where an investigation results in a Sanction by the Market Monitoring Unit, the Market Monitoring Unit shall direct its notice of such result to a responsible representative of the Scheduling Coordinator and, as provided in Section 37.8.4, to the Market Participant(s) that are the subject(s) of the investigation at the officer level.

37.8.9 Record of Investigation.

Where an investigation results in a Sanction, the Market Monitoring Unit will maintain a record of the investigation until its decision has been finally reviewed, if review is sought, or until the period for seeking review has expired.

37.8.10 Review of Determination.

A Market Participant that receives a Sanction may obtain immediate review of the Market Monitoring Unit's determination by directly appealing to FERC, in accordance with FERC's rules and procedures. In such case, the applicable Scheduling Coordinator shall also dispute the Preliminary Settlement Statement containing the financial penalty, in accordance with Section 11 of the ISO Tariff. The Preliminary Settlement Statement dispute and appeal to FERC must be made in accordance with the timeline for raising disputes specified in Section 11.7.2 of the ISO Tariff. The penalty will be tolled until FERC renders its decision on the appeal. The disposition by FERC of such appeal shall be final, and no separate dispute of such Sanction may be initiated under Section 13 of the ISO Tariff, except as provided in Section 37.9.3.4. For the purpose of applying the time limitations set forth in Section 37.10.1, a sanction will be considered assessed when it is included on a Preliminary Settlement Statement, whether or not the ISO accepts a Scheduling Coordinator's dispute of such Preliminary Settlement Statement pending resolution of an appeal to FERC in accordance with this section or Section 37.9.3.3.

37.9 Administration of Sanctions

37.9.1 Assessment; Waivers and Adjustments. Penalty amounts for violation of these Rules of Conduct shall be calculated as specified in Section 37.2 through Section 37.7. A Sanction specified in this Section 37 may be modified by FERC when it determines that such adjustment is just and reasonable. The ISO may make a recommendation to FERC to modify a Sanction. An adjustment generally shall be deemed appropriate if the prescribed Sanction appears to be insufficient to deter the prohibited behavior, or if the circumstances suggest that the violation was inadvertent, unintentional, or some other mitigating circumstances exist.

37.9.2 Excuse.

The following circumstances shall excuse a violation of a Rule of Conduct under the terms of this ISO Tariff:

37.9.2.1 Uncontrollable Force.

No failure by a Market Participant to satisfy the Rules of Conduct shall be subject to penalty to the extent and for the period that the Market Participant's inability to satisfy the Rules of Conduct is caused by an event or condition of Uncontrollable Force affecting the Market Participant; provided that the Market Participant gives notice to the ISO of the event or condition of Uncontrollable Force as promptly as possible after it knows of the event or condition and makes all reasonable efforts to cure, mitigate, or remedy the effects of the event or condition.

37.9.2.2 Safety, Licensing, or Other Requirements.

Failure by a Market Participant to perform its obligations shall not be subject to penalty if the Market Participant is able to demonstrate that it was acting in accordance with Section 4.2.1 of the ISO Tariff.

37.9.2.3 Emergencies.

Failure by a Market Participant to perform its obligations may not be subject to penalty if the Market Participant is able to demonstrate that it was acting in good faith and consistent with Good Utility Practice to preserve System Reliability in a System Emergency, unless contrary to an ISO operating order.

37.9.2.4 Conflicting Directives.

To the extent that any action or omission by a Market Participant is specifically required by a FERC Order or ISO operating order, the Market Participant may not be subject to penalty for that act or omission.

37.9.3 Settlement.

37.9.3.1 Settlement Statements.

The ISO will administer any penalties issued under this Enforcement Protocol through Preliminary Settlement Statements, and Final Settlement Statements issued to the responsible Scheduling Coordinator by the ISO. Before invoicing a financial penalty through the Settlement process, the ISO will provide a description of the penalty to the responsible Scheduling Coordinator and all Market Participants the Scheduling Coordinator represents that are liable for the penalty, when the ISO has sufficient objective information to identify and verify responsibility of such Market Participants. The ISO shall specify whether such penalty is modified pursuant to Section 37.2.5, Section 37.4.4 or Section 37.9.1. The description shall include the identity of the Market Participant that committed the violation and the amount of the penalty. Where FERC has determined the Sanction, the ISO will provide such of the above information as is provided to it by FERC. The ISO also may publish this information under the ISO Home Page after Final Settlement Statements are issued.

37.9.3.2 Payment.

Except as provided in Section 37.2.5, Section 37.4.4, Section 37.8.10 or Section 37.9.3.3 below, the Scheduling Coordinator shall be obligated to pay all penalty amounts reflected on the Preliminary and Final Settlement Statements to the ISO pursuant to the ISO's Settlement process, as set forth in Section 11 of the ISO Tariff.

37.9.3.3 Other Responsible Party.

Where a party or parties other than the Scheduling Coordinator is responsible for the conduct giving rise to a penalty reflected on a Preliminary or Final Settlement Statement, and where the Scheduling Coordinator bears no responsibility for the conduct, such other party or parties ultimately shall be liable for the penalty. Under such circumstances, the Scheduling Coordinator shall use reasonable efforts to obtain payment of the penalty from the responsible party(ies) and to remit such payment to the ISO in the ordinary course of the settlement process. In the event that the responsible party(ies) wish to dispute the penalty, or the Scheduling Coordinator otherwise is unable to obtain payment from the responsible parties, the Scheduling Coordinator shall notify the ISO and dispute the Preliminary Settlement Statement. The ISO promptly shall notify FERC. If the ISO finds that a Market Participant separate from the Scheduling Coordinator that is unable to obtain payment from the responsible party(ies) is solely responsible for a violation, the Scheduling Coordinator that is unable to obtain payment may net its payment of its Invoice amount by the amount of the penalty in question. The ISO may refuse to offer further service to any responsible party that fails to pay a penalty, unless excused under the terms of the Tariff or this Enforcement Protocol, by providing notice of such refusal to the Scheduling Coordinator. Following such notice, the Scheduling Coordinator shall be liable for any subsequent penalties assessed on account of such responsible party.

37.9.3.4 Dispute of FERC Sanctions.

The right that a Market Participant may otherwise have under the Tariff or this Enforcement Protocol to dispute a penalty that has been determined by FERC shall be limited to a claim that the ISO failed properly to implement the penalty or other Sanction ordered by FERC, except as provided by Section 37.2.5 and Section 37.4.4.

37.9.4 Disposition of Proceeds.

The ISO shall collect penalties assessed pursuant to this Section 37.9 and deposit such amounts in an interest bearing trust account. After the end of each calendar year, the ISO shall distribute the penalty amounts together with interest earned through payments to Scheduling Coordinators as provided herein. For the purpose of this Section 37.9.4, “eligible Market Participants” shall be those Market Participants that were not assessed a financial penalty pursuant to this Section 37 during the calendar year.

Each Scheduling Coordinator that paid GMC during the calendar year will identify, in a manner to be specified by the ISO, the amount of GMC paid by each Market Participant for whom that Scheduling Coordinator provided service during that calendar year. The total amount assigned to all Market Participants served by that Scheduling Coordinator in such calendar year (including the Scheduling Coordinator itself for services provided on its own behalf), shall equal the total GMC paid by that Scheduling Coordinator.

The ISO will calculate the payment due each Scheduling Coordinator based on the lesser of the GMC actually paid by all eligible Market Participants represented by that Scheduling Coordinator, or the product of a) the amount in the trust account, including interest, and b) the ratio of the GMC paid by each Scheduling Coordinator on behalf of eligible Market Participants, to the total of such amounts paid by all Scheduling Coordinators. Each Scheduling Coordinator is responsible for distributing payments to the eligible Market Participants it represented in proportion to GMC collected from each eligible Market Participant.

Prior to allocating the penalty proceeds, the ISO will obtain FERC’s approval of its determination of eligible Market Participants and their respective shares of the trust account proceeds. If the total amount in the trust account to be so allocated exceeds the total GMC obligation of all eligible Market Participants, then such excess shall be treated in accordance with Section 11.8.5.3(b).

37.10 Miscellaneous.

37.10.1 Time Limitation.

An investigation of events potentially subject to Sanction under this Section 37 must be commenced within 90 days of discovery of the events. Sanctions may be assessed under this Section 37 up to one year after discovery of the events constituting the violation, but no later than three years after the date of the violation. Nothing in this section shall limit the rights or liabilities of any party under any other provision of applicable laws, regulations or tariff provisions.

37.10.2 No Limitation on Other Rights.

Nothing contained in this Section 37 shall limit the ability of the ISO to collect information from Market Participants or to establish new provisions pursuant to Section 15 of the ISO Tariff.

37.11 Method for Calculating Penalties.

1. Method for Calculating Inaccurate Meter Data Penalty.

There is no Sanction for the submission of inaccurate meter data used for Preliminary Settlement Statements. However, an error in submitted meter data that is discovered after issuance of Final Settlement Statements constitutes a Rule of Conduct violation. The level of the Sanction depends on whether the Scheduling Coordinator or the ISO discovered the error. An increased penalty will apply for errors that are discovered by the ISO.

Table A1 below shows how the level of the Sanction depends on the following factors: whether or not the Scheduling Coordinator finds the error; whether or not the Scheduling Coordinator owes the market, and whether or not the ISO reruns settlement of the market. If the ISO reruns the market, then settlement to all Scheduling Coordinators is recalculated, and the impact of such reruns on charges assessed will be considered. A charge equal to 30% of the estimated value of the Energy error will apply if the Scheduling Coordinator discovers the error, or 75% of the estimated value of the Energy error if the ISO discovers the error. Penalty assessment and disposition of penalty proceeds will be administered as described in Section 37.9.1 and Section 37.9.4 respectively. A Sanction will not be imposed unless such Sanction is more than $1,000 for at least one Trading Day during the period for which there was incomplete or inaccurate meter data.

Table A1 – Calculation of Inaccurate Meter Data Penalty When There Is A Market Rerun

Case	Does SC Owe Market?	
Case 1: SC Identifies Inaccurate Meter Data	Yes	Charge = (MWh x Hourly Ex Post Price[1]) x 0.30
Case 1: SC Identifies Inaccurate Meter Data	No	Charge = (MWh x Hourly Ex Post Price[1]) x 0.30
Case 2: ISO Identifies Inaccurate Meter Data	Yes	Charge = (MWh x Hourly Ex Post Price[1]) x 0.75
Case 2: ISO Identifies Inaccurate Meter Data	No	Charge = (MWh x Hourly Ex Post Price[1]) x 0.75

Note to Table A1:

The applicable price will be the greater of the Hourly Ex Post Price or $10/MWh. The Hourly Ex Post Price used will be the value posted under the ISO Home Page for each Trading Hour of the applicable Trading Day.

2. Method for Calculating Inaccurate Meter Data Penalty When The Market Is Not Re-Run.

If the Market is not re-run, for cases of inaccurate meter data, Table A2 will be used to determine and allocate the penalty proceeds. This method approximates the financial impact on the market; however, it does not completely reflect all the settlement consequences of inaccurately submitted meter data. This will be considered a market adjustment. The approximated value of the inaccurate meter data in question will be calculated and returned to the Market based on the average of the pro rata share of Unaccounted For Energy (UFE) charged in the UDC territory during the period of the inaccurate meter data event. The 30% or 75% penalty will be distributed as discussed in Section 37.9.4. For cases where the market is not re-run and the Scheduling Coordinator does not owe the market, then no market adjustment will be performed.

TABLE A2- Calculation Of Inaccurate Meter Data Penalty When There Is No Market Re-Run

Case	Does SC Owe Market?	ISO does not perform a market settlement re-run
Case 1: SC Identifies Inaccurate Meter Data	Yes	Market Adjustment = (MWh x Hourly Ex Post Price[1]) Penalty = (MWh x Hourly Ex Post Price[1]) x 0.30
Case 1: SC Identifies Inaccurate Meter Data	No	No Market Adjustment will be made Penalty = (MWh x Hourly Ex Post Price[1]) x 0.30
Case 2: ISO Identifies Inaccurate Meter Data	Yes	Market Adjustment = (MWh x Hourly Ex Post Price[1]) Penalty = (MWh x Hourly Ex Post Price[1]) x 0.75
Case 2: ISO Identifies Inaccurate Meter Data	No	No Market Adjustment will be made Penalty = (MWh x Hourly Ex Post Price[1]) x 0.75

Notes to Table A2:

The applicable price will be the greater of the Hourly Ex Post Price or $10/MWh. The Hourly Ex Post Price used will be the value posted under the ISO Home Page for each Trading Hour of the applicable Trading Day.

A Sanction will be imposed only if the Sanction is more than $1,000 for at least one Trading Day during the period for which there was incomplete or inaccurate meter data.

If the error is to the detriment of the responsible Scheduling Coordinator (e.g., under-reported generation or over-reported load), and the ISO does not rerun the market, then no correction will be made, representing an implicit penalty of 100% of the value of the Energy. If the market is rerun after the error is corrected, then the Scheduling Coordinator will be given credit for the additional Energy through the normal Settlement process. If the Scheduling Coordinator is paid for an error due to a market rerun, then a Sanction will be assessed to assure that market reruns do not diminish the incentive to correct such errors. This Sanction would be 30% of the Energy value of the error if the Scheduling Coordinator discovers the error, or 75% estimated value of the error if the ISO discovers the error.

If the error is to the detriment of the market, then a charge equal to 30% or 75% of the estimated value of the error, as appropriate, will be added to the charge for the Energy. If there is no market rerun, then the cost of Energy supplied by the ISO (and inappropriately charged to the market as Unaccounted for Energy) must be recovered as well, and the charge will be equal to 130% or 175% of the estimated value of the error, as appropriate.

ARTICLE IV – MARKET MONITORING AND MARKET POWER MITIGATION

38 MARKET MONITORING.

38.1 Objectives and Scope.

This Section sets forth the workplan and, where applicable, the rules under which the ISO Department of Market Analysis and ISO Market Surveillance Committee will monitor the ISO Markets to identify abuses of market power, to ensure to the extent possible the efficient working of the ISO Markets immediately upon commencement of their operation, and to provide for their protection from abuses of market power in both the short term and the long term, and from other abuses that have the potential to undermine their effective functioning or overall efficiency in accordance with Section 38.1.1 of the ISO Tariff. Such monitoring activities will be carried out by, among other ISO departments, the ISO Department of Market Analysis and the ISO Market Surveillance Committee to be established and to operate under the terms of this Protocol, as set forth below. These protocols provide a general framework for the operation of the Department of Market Analysis and the Market Surveillance Committee and are not intended to limit the activities or remedies available to these entities or to the ISO as a whole elsewhere in the ISO Tariff or otherwise under law.

38.1.1 Market Surveillance: Changes to Operating Rules and Protocols.

The ISO shall keep the operation of the markets that it administers under review to determine whether changes in its operating rules or ISO Protocols would improve the efficiency of those markets or prevent the exercise of market power by any Market Participant; and it shall institute necessary changes in accordance with this Section 38. The details of the ISO Market Monitoring and Information Protocol are set forth in Appendix P.

38.1.2 Reporting Requirements.

This Section of the ISO Tariff sets forth the information dissemination, publication and reporting activities and other means of providing information that the ISO generally undertakes to meet its reporting requirements to regulatory agencies, Market Participants and others. The goal of the reporting provisions is to adequately inform regulatory agencies, law enforcement agencies, policymakers, Market Participants and others of the state of the ISO Markets, especially their competitiveness and efficiency. This function is designed to facilitate efficient corrective actions to be taken by the appropriate body or bodies when required.

38.2 Practices Subject to Scrutiny – General.

The Department of Market Analysis shall monitor the activities of Market Participants that affect the operation of the ISO Markets and that provide indications of the phenomena set forth below in this Section 38.2. Where appropriate, it will take such further action as it considers necessary under Section 38.4.

38.2.1 Abuse of Reliability Must-Run Unit Status.

Where Generating Units are determined by the ISO to be Reliability Must-Run Units, circumstances that indicate that such Generating Units are being operated in a manner that will adversely affect the competitive nature and efficient workings of the ISO Markets.

38.2.2 ISO and Other Market Design Flaws.

Design flaws and inefficiencies in the ISO Tariff, ISO Protocols and operational rules and procedures of the ISO, including the potential for problems between the ISO and other independent power markets or exchanges insofar as they affect the ISO Markets.

38.2.3 Market Structure Flaws.

With respect to flaws in the overall structure of the California energy markets that may reveal undue concentrations of market power in Generation or other structural flaws, the Department of Market Analysis shall provide such information or evidence of such flaws and such analysis as it may conduct to the ISO CEO and/or to the ISO Governing Board, subject to due protections of confidential or commercially sensitive information. After due internal consultation, if instructed by any of such ISO institutions or persons, the Department of Market Analysis shall also provide such information or evidence to the Market Surveillance Committee, the appropriate regulatory and antitrust enforcement agency or agencies, subject to due protections of confidential or commercially sensitive information. The Department of Market Analysis shall, at the direction of the ISO CEO and/or the ISO Governing Board, or their designee, provide such other evidence, views, analyses or testimony as may be appropriate or required and as it is reasonably capable of providing to assist the investigations of such agencies.

38.3 Scrutiny of Participant Changes Potentially Affecting Market Structure.

The Department of Market Analysis may undertake the following measures to monitor the special circumstances that may affect the operation of the ISO Markets due to corporate reorganizations including bankruptcies or changes in affiliate relationships and may recommend corrective actions as provided in Section 38.4.

38.3.1 Exercises of Horizontal Market Power.

The Department of Market Analysis may analyze the impact of changes in market structure on the ability of Market Participants to exercise short-term horizontal market power.

38.4 Response Action by ISO.

38.4.1 Corrective Actions.

Where the monitoring activities or any consequent investigations carried out by the Department of Market Analysis pursuant to Section 38.2 and Appendix P.1 reveal a significant possibility of the presence of or potential for exercises of market power that would adversely affect the operation of the ISO Markets, or other markets interconnected or interdependent on the ISO Markets, the Department of Market Analysis shall take the appropriate measures under this section and under Appendix P to institute the corrective action most effective and appropriate for the situation or, in the case of markets interconnected to or interdependent on the ISO Markets, the Department of Market Analysis may recommend corrective actions to the appropriate regulatory agencies.

38.4.2 Further Actions.

Where the monitoring activities of or any consequent investigations carried out by the Department of Market Analysis pursuant to Sections 38.2 and 38.3 reveal that activities or behavior of Market Participants in the ISO Markets have the effect of, or potential for, undermining the efficiency, workability or reliability of the ISO Markets to give or to serve such Market Participants an unfair competitive advantage over other Market Participants, the Department of Market Analysis shall fully investigate and analyze the effect of such activities or behavior and make recommendations to the ISO CEO and the ISO Governing Board for further action by the ISO or, where necessary, by other entities. The Department of Market Analysis may, where appropriate, make specific recommendations to the ISO CEO and to the ISO Governing Board for amendment to rules and protocols under its control, or for changes to the structure of the ISO Markets, and the Department of Market Analysis may recommend actions, including fines or suspensions, against specific entities in order to deter such activities or behavior.

38.4.3 Adverse Effects of Transition Mechanisms.

Should the monitoring and analysis conducted under Appendix P reveal significant adverse effects of transition mechanisms on competition in or the efficient operation of the ISO Markets, the Department of Market Analysis shall examine and fully assess the efficacy of all possible measures that may be taken by the ISO, in order to prevent or to mitigate such adverse effects. The Department of Market Analysis shall make such recommendations to the CEO of the ISO and to the ISO Governing Board as it considers appropriate for action by the ISO and/or for referral to regulatory or law enforcement agencies. Such proposed measures may include, but shall not be limited to the following:

38.4.3.1 the use of direct bid caps as a mechanism to prevent or mitigate artificially high Market Clearing Prices caused by abuses of market power;

38.4.3.2 the use of contracts for differences for eliminating the incentive for Generators to bid ISO prices to artificially high levels enabled by the presence of market power;

38.4.3.3 calling upon Reliability Must-Run Units to operate; and to modify Reliability Must-Run Contracts;

38.4.3.4 bid floors to prevent or mitigate the possible exercise of below-cost bidding or predatory pricing.

In the event that the ISO Governing Board adopts, and where necessary obtains regulatory approval for, any measure proposed pursuant to Section 38.4.3, the Department of Market Analysis shall monitor the implementation and effect of such measure on the state of the ISO Markets and shall periodically report on them to the CEO and the ISO Governing Board.

39 RULES LIMITING CERTAIN ENERGY AND ANCILLARY SERVICE BIDS.

39.1 Damage Control Bid Cap.

Notwithstanding any other provision of this ISO Tariff, Damage Control Bid Cap provisions of Sections 39.2 and 39.3 shall apply to the ISO's Energy and Ancillary Service capacity markets.

39.2 Maximum Bid Level.

The maximum bid level in the ISO's Energy markets shall be $400/MWh. Market Participants may submit bids in the ISO's Energy markets above $400/MWh, however, any accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost-justification and refund.

The maximum bid level applicable to Adjustment Bids used in the ISO's Congestion Management markets shall be $400/MWh, and the ISO shall not accept Adjustment Bids in excess of that bid level.

The maximum bid level in the ISO's Ancillary Service capacity markets shall be $400/MWh. Market Participants may submit bids in the ISO's Ancillary Serivce capacity markets above $400/MWh, however, any accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost-justification and refund.

39.3 Negative Decremental Energy Bids.

Negative decremental Energy bids into the ISO Markets less than -$30/MWh (minus thirty dollars per MWh) shall not be eligible to set any Market Clearing Price and, if Dispatched, shall be paid as bid. If the ISO Dispatches a bid below -$30/MWh, the supplier must submit a detailed breakdown of the component costs justifying the bid to the ISO and to the Federal Energy Regulatory Commission no later than seven (7) days after the end of the month in which the bid was submitted. The ISO will treat such information as confidential and will apply the procedures in Section 20.4 of this ISO Tariff with regard to requests for disclosure of such information. The ISO shall pay suppliers for amounts in excess of $-30/MWh after those amounts have been justified.

ARTICLE V – RESOURCE ADEQUACY

40 RESOURCE ADEQUACY.

40.1 Applicability.

This Section 40 applies to all Scheduling Coordinators representing Load Serving Entities serving retail Load within the ISO Control Area. For purposes of this Section 40 of the ISO Tariff, Load Serving Entity is defined as: (1) any entity serving retail Load under the jurisdiction of the California Public Utilities Commission (hereinafter "CPUC"), including an Electrical corporation under section 218 of the California Public Utilities Code (hereinafter "PUC"), an Electric service provider under section 218.3 of the PUC, and a Community choice aggregator under section 331.1 of the PUC (hereinafter collectively "CPUC Load Serving Entities"); and (2) all entities serving retail Load in the ISO Control Area not within the jurisdiction of the CPUC including: (i) a local publicly owned electric utility under section 9604 of the PUC; (ii) the State Water Resources Development System commonly known as the State Water Project; and (iii) any Federal entities, including but not limited to Federal Power Marketing Authorities, that serve retail Load (hereafter collectively "non-CPUC Load Serving Entities"). Load Serving Entity shall not include customer generation located on the customer's site or providing electric service through arrangements authorized by Section 218 of the PUC, if the customer generation, or the Load it serves, meets one of the following criteria: (i) it takes standby service from the electrical corporation on a commission-approved rate schedule that provides for adequate backup planning and operating reserves for the standby customer class; (ii) it is not physically interconnected to the electric transmission or distribution grid, so that if the customer generation fails, backup electricity is not supplied from the electricity grid; or (iii) there is physical assurance that the Load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation.

40.2 Submission of Annual and Monthly Resource Adequacy Plan.

40.2.1 Annual Resource Adequacy Plan.

Each Scheduling Coordinator for a Load Serving Entity serving Load within the ISO Control Area must provide the ISO with an annual Resource Adequacy Plan; however, Scheduling Coordinators representing a Load Serving Entity with an MSS Agreement shall submit the information required by this section pursuant to the terms and formal standards set forth in the MSS Agreement. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted on the schedule and in the form approved by the CPUC. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area, except Load Serving Entities with an MSS Agreement, shall be submitted no later than September 30th of each year and in the form set forth on the ISO Website. Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities should be identical. The annual Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin under Section 40.4, or portion thereof as established by the CPUC or applicable Local Regulatory Authority, and must apply the Net Qualifying Capacity requirements of Section 40.5.2.

40.2.2 Monthly Resource Adequacy Plan.

Each Scheduling Coordinator for a Load Serving Entity serving Load within the ISO Control Area must provide the ISO with a monthly Resource Adequacy Plan; however, (1) Scheduling Coordinators representing a Load Serving Entity with an MSS Agreement shall submit the information required by this section pursuant to the terms and formal standards set forth in the MSS Agreement and (2) Scheduling Coordinators for a Load Serving Entity serving Load within the ISO Control Area in a forecasted peak amount of less than (1) MW on average per day over the compliance year may notify the ISO that the Load Serving Entity's annual Resource Adequacy Plan pursuant to Section 40.2.1 will constitute its monthly Resource Adequacy Plan under this section for each month of the following compliance year.

The monthly Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted on the schedule and in the form approved by the CPUC. The monthly Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area, except for Load Serving Entities with an MSS Agreement, shall be submitted no later than on the last business day of the second month prior to the compliance month (e.g., March 31 for May) and in the form set forth on the ISO's Website. Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities should be identical. The monthly Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin under Section 40.4 for the relevant reporting month and must apply the Net Qualifying Capacity requirements of Section 40.5.2.

40.2.3 Resource Adequacy Plan Compliance.

The ISO will evaluate whether each monthly Resource Adequacy Plan submitted by a Scheduling Coordinator on behalf of a Load Serving Entity serving Load within the ISO Control Area satisfies the Load Serving Entity's obligation to procure sufficient Net Qualifying Capacity to comply with its Planning Reserve Margin under Section 40.4. If a Scheduling Coordinator for a Load Serving Entity submits a Resource Adequacy Plan that the ISO identifies as not demonstrating compliance with Resource Adequacy rules adopted by the CPUC or other Local Regulatory Authority, as applicable, the ISO will, within 10 business days, first notify the relevant Scheduling Coordinator, or in the case of a mismatch between Resource Adequacy Plan(s) and Supply Plan(s), the relevant Scheduling Coordinators in an attempt to resolve the issue. If this process does not resolve the ISO's concern, the ISO will notify the CPUC or other appropriate Local Regulatory Authority of the potential deficiency. To the extent that the CPUC or other appropriate Local Regulatory Authority allows Load Serving Entities under its jurisdiction to cure the identified deficiency or determines that no deficiency exists, the Scheduling Coordinator shall inform the ISO at least 10 days before the effective month. If the deficiency is not resolved prior to the 10th day before the effective month, the ISO will use the information contained in the Supply Plan to set

Resource Adequacy Resources' obligations under this section of the ISO Tariff for the applicable reporting month.

40.2.4 Reporting of Enforcement Actions.

To the extent that the CPUC or other Local Regulatory Authority has not adopted rules allowing public access to records or information regarding action taken for violations of its Resource Adequacy policies and rules, the Scheduling Coordinator for each Load Serving Entity serving Load in the ISO Control Area notified of a potential failure to comply by the ISO and not resolved under 40.2.3 must report to the ISO within thirty (30) days of any action taken by the appropriate Local Regulatory Authority in response to the deficiency notification.

40.2.5 Compliance with Submission Obligation.

Scheduling Coordinators representing Load Serving Entities Serving Load in the ISO Control Area that fail to provide the ISO with annual or monthly Resource Adequacy Plans as set forth in this ISO Tariff shall be subject to Section 37.6.1 of the ISO Tariff.

40.3 Demand Forecasts.

The annual and monthly Resource Adequacy Plan must include a Demand Forecast as follows:

a. For CPUC Load Serving Entities, the Demand Forecast shall be the Demand Forecast required by the CPUC. To the extent the ISO has not received a CPUC Load Serving Entity's load forecast through the CPUC's Resource Adequacy process, the Scheduling Coordinators for the CPUC Load Serving Entities must provide to the ISO a copy of the Demand Forecast that they provided to the CPUC and CEC, subject to the confidentiality terms established by the CPUC in its proceeding.

b. For non-CPUC Load Serving Entities, the Demand Forecast shall be the Demand Forecast required by the applicable Local Regulatory Authority. Scheduling Coordinators for non-CPUC Load Serving Entities must provide data and/or supporting information, as requested by the ISO, for the Demand Forecasts required by this Section for each represented non-CPUC Load Serving Entity.

c. If the CPUC or other Local Regulatory Authority has not established a requirement to prepare a Demand Forecast, the Scheduling Coordinator for the Load Serving Entity shall prepare and provide the ISO with a Demand Forecast that shall be the Load Serving Entity's monthly non-coincident peak Demand Forecast for its Service Area, for its MSS area, or in each Service Area of an Original Participating TO in which the Load Serving Entity serves Load, unless the Load Serving Entity agrees to utilize a coincident peak determination provided by the California Energy Commission for such Load Serving Entity. Scheduling Coordinators for Load Serving Entities covered by this subsection must provide data and/or supporting information, as requested by the ISO, for the Demand Forecasts required by this Section for each represented Load Serving Entity.

For Load Serving Entities that are local publicly owned electric utilities as defined in Section 9604 of the PUC, the Demand Forecasts required by this Section 40.3 should be consistent with Section 9620(a) of the PUC, as it may be amended from time to time, requiring that such Load Serving Entities meet their

Planning Reserve Margin, peak demand, and operating reserves.

40.4 Planning Reserve Margin.

The monthly Resource Adequacy Plan must include a level of Resource Adequacy Capacity sufficient to meet 100% of the Demand Forecast in Section 40.3 plus a Planning Reserve Margin as follows:

a. For Scheduling Coordinators representing CPUC Load Serving Entities, the Planning Reserve Margin shall be that adopted by the CPUC.

b. For Scheduling Coordinators representing non-CPUC Load Serving Entities, the Planning Reserve Margin shall be that adopted by the appropriate Local Regulatory Authority.

c. Scheduling Coordinators representing a Load Serving Entity that has proposed a Planning Reserve Margin to, and is pending consideration by, the CPUC or other Local Regulatory Authority, the Planning Reserve Margin shall be that pending before the CPUC or other Local Regulatory Authority.

d. For Scheduling Coordinators representing a Load Serving Entity that has not proposed a Planning Reserve Margin to the CPUC or other Local Regulatory Authority or the CPUC or other Local Regulatory Authority has not established a Planning Reserve Margin, the Planning Reserve Margin shall be no less than 115% of the peak hour of the month in the Demand Forecast set forth in Section 40.3.

40.5 Determination of Resource Adequacy Capacity.

Resource Adequacy Capacity shall be the quantity of capacity in MWs from a resource listed in a Resource Adequacy Plan. Resource Adequacy Capacity cannot exceed a resource's Net Qualifying Capacity.

40.5.1 Qualifying Capacity.

Qualifying Capacity is the capacity from a resource prior to application of the Net Capacity provisions of Section 40.5.2. The criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO.

To the extent the CPUC or other Local Regulatory Authority has not established for a particular Load Serving Entity the criteria for determining the tupes of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types at the time the Load Serving Entity must submit a Resource Adequacy Plan, the criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types may be provided by the Load Serving where such criteria has been proposed by the Load Serving Entity and is pending before the CPUC or applicable Local Regulatory Authority. Only if criteria for determining the tupes of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types has not been provided by the CPUC or other Local Regulatory Authority or Load Seving Enetity as provided for in this Section, then Section 40.13 will apply. The ISO shall use the criteria provided by the CPUC, other Local Regulatory Authority, or Load Serving Entity or, if necessary, Section 40.13, to determine and verify, if necessary, the Qualifying Capacity of all resources listed in a Resource Adequacy Plan; however, to the extent a resource is listed by one or more Scheduling Coordinators in their respective Resource Adequacy Plans, which apply the criteria of more than one regulatory entity that leads to conflicting Qualifying Capacity values for that resource, the ISO will apply the respective Qualifying Capacity formulas applicable for each Load Serving Entity.

40.5.2 Net Qualifying Capacity.

Net Qualifying Capacity is Qualifying Capacity, determined under the criteria provided by the CPUC or other Local Regulatory Authority or, if such criteria is not provided by the CPUC or Local Regulatory Authority, under Section 40.13 of this ISO Tariff, reduced, as applicable, based on: (1) testing and verification or (2) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the ISO pursuant to the provisions of this ISO Tariff. The ISO shall produce a report, posted to the ISO Website and updated from time to time, setting forth the Net Qualifying Capacity of Participating Generators. All other resources may be included in the report under this Section upon their request. Any disputes as to the ISO's determination regarding Net Qualifying Capacity shall be subject to the ISO's alternative dispute resolution procedures.

40.5.2.1 Deliverability Within the ISO Control Area.

In order to determine Net Qualifying Capacity from a Generating Unit, the ISO will determine that the Generating Unit is able to serve the aggregate of Load by means of a deliverability analysis. The deliverability analysis will be performed annually and shall focus on peak Demand conditions. The ISO will review its input assumptions and draft results with Market Participants before completing its determination. The ISO will coordinate with the CPUC and other Local Regulatory Authorities so that the results of the deliverability analysis can be incorporated in annual and monthly Resource Adequacy Plans. The results of the ISO's annual deliverability analysis shall be effective for a period no shorter than the entire next calendar year. To the extent the deliverability analysis shows that the Qualifying Capacity of a Generating Unit is not deliverable to the aggregate of Load under the conditions studied, the Qualifying Capacity of the Generating Unit will be reduced on a MW basis for the capacity that is undeliverable.

40.5.2.2 Deliverability of Imports.

40.5.2.2.1 Available Import Capability Assignment Process.

For Resource Adequacy Plans covering any period after December 31, 2007, total Available Import Capability will be assigned on an annual basis for a one-year term to Load Serving Entities serving Load in the ISO Control Area and other Market Participants through their respective Scheduling Coordinators, as described by the following sequence of steps. However, should the CPUC modify by decision its compliance period from January to December of the calendar year to May through April of the calendar year, the CAISO shall extend the effectiveness of the assignment for 2008 Compliance Year through April 2009.

Step 1: Determination of Maximum Import Capability on Branch Groups into the ISO Control Area: The ISO shall establish the Maximum Import Capability for each branch group into the ISO Control Area, and will post those values on the ISO website for RA Compliance Year 2008 by July 1, 2007, and for subsequent RA Compliance Years in accordance with the schedule and process set forth in the business practice manual.

Step 2: Determination of Available Import Capability by Accounting for Existing Contracts and Transmission Ownership Rights Held by Out-of-ISO Control Area LSEs: For each branch group, the Available Import Capability will be determined by subtracting from the Maximum Import Capability established in Step 1 for each branch group the import capability on each branch group associated with (i) Existing Contracts and (ii) Transmission Ownership Rights held by load serving entities that do not serve Load within the ISO Control Area. The remaining sum of all branch group Available Import Capability is the Total Import Capability. Total Import Capability shall be used to determine the Load Share Quantity for each Load Serving Entity that serves Load within the ISO Control Area.

Step 3: Determination of Existing Contract Import Capability by Accounting for Existing Contracts and Transmission Ownership Rights Held by In-ISO Control Area LSEs: From the Available Import Capability remaining on each branch group after Step 2 above, Existing Contracts and Transmission Ownership Rights held by Load Serving Entities that serve Load within the ISO Control Area shall be reserved for the holders of such commitments and will not be subject to reduction under any subsequent steps in this Section. The import capability reserved pursuant to this Step 3 is the Existing Contract Import Capability.

Step 4: Assignment of Pre-RA Import Commitments: From the Available Import Capability remaining on each branch group after reserving Existing Contract Import Capability under Step 3 above, the ISO will assign to Load Serving Entities serving Load within the ISO Control Area Pre-RA Import Commitment Capability on a particular branch group based on Pre-RA Import Commitments in effect (where a supplier has an obligation to deliver the Energy or make the capacity available) at any time during the RA Compliance Year for which the Available Import Capability assignment is being performed. The Pre-RA Import Commitment will be assigned to the branch group selected by the Load Serving Entity during the RA Compliance Year 2007 import capability assignment process, which was required to be based on the branch group upon which the Energy or capacity from the Pre-RA Import Commitment had been primarily scheduled or, for a Pre-RA Import Commitment without a scheduling history at the time of the RA Compliance Year 2007 import capability assignment process, the primary branch group upon which the Energy or capacity was anticipated to be scheduled. To the extent a Pre-RA Import Commitment was not presented during the RA Compliance Year 2007 import capability assignment process, the Load Serving Entity shall select the branch group upon which the Pre-RA Import Commitment is primarily anticipated to be scheduled during the term of the Pre-RA Import Commitment and that selection shall be utilized in future annual Available Import Capability assignment processes.

Capability of the branch group, such that the MW represented in all Pre-RA Import Commitments utilizing the branch group exceed the branch group's Available Import Capability in excess of that reserved for Existing Contracts and Transmission Ownership Rights under Steps 2 and 3, the Pre-RA Import Commitments will be assigned Pre-RA Import Commitment Capability, based on the Import Capability Load Share Ratio of each Load Serving Entity submitting Pre-RA Import Commitments on the particular branch group. To the extent this initial assignment of Pre-RA Import Commitment Capability has not fully assigned the Available Import Capability of the particular over requested branch group, the remaining Available Import Capability on the over requested branch group will be assigned until fully exhausted based on the Import Capability Load Share Ratio of each Load Serving Entity whose submitted Pre-RA Import Commitment has not been fully satisfied by the previous Import Capability Load Share Ratio assignment iteration. The Available Import Capability assigned pursuant to this Step 4 is the Pre-RA Import Commitment Capability.

Step 5: Assignment of Remaining Import Capability Limited by Load Share Quantity: The Total Import Capability remaining after Step 4 will be assigned only to Load Serving Entities serving Load within the ISO Control Area that have not received Existing Contract Import Capability and Pre-RA Import Commitment Capability under Steps 3 and 4, that exceed the Load Serving Entity's Load Share Quantity. This Total Import Capability will be assigned until fully exhausted to those Load Serving Entities eligible to receive an assignment under this Step based on each Load Serving Entity's Import Capability Load Share Ratio up to, but not in excess of, its Load Share Quantity. The quantity of Total Import Capability assigned to the Load Serving Entity under this Step is the Load Serving Entity's Remaining Import Capability. This Step 5 does not assign Remaining Import Capability on a specific branch group.

Step 6: ISO Posting of Assigned and Unassigned Capability: Following the completion of Step 5, the ISO will post to its website for RA Compliance Year 2008 by July 9, 2007 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual the following information:

a. The Total Import Capability;

b. The quantity in MW of Existing Contracts and Transmission Ownership Rights assigned to each branch group, distinguishing between Existing Contracts and Transmission Ownership Rights held by Load Serving Entities within the ISO Control Area and those held by load serving entities outside the ISO Control Area;

c. The aggregate quantity in MW, and identify the holders, of Pre-RA Import Commitments assigned to each branch group; and

d. The aggregate quantity in MW of Available Import Capability after Step 4, the identity of the branch groups with Available Import Capability, and the MW quantity of Available Import Capability on each such branch group.

Step 7: ISO Notification of LSE Assignment Information: Following the completion of Step 5, by July 9, 2007 for RA Compliance Year 2008 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, the ISO will notify the Scheduling Coordinator for each Load Serving Entity of:

a. The Load Serving Entity's Import Capability Load Share;

b. The Load Serving Entity's Load Share Quantity; and

c. The amount of, and branch group on which, the Load Serving Entity's Existing Contract Import Capability and Pre-RA Import Commitment Capability, as applicable, has been assigned; and

d. The Load Serving Entity's Remaining Import Capability.

Step 8: Transfer of Import Capability: Up to and including July 17, 2007 for RA Compliance Year 2008 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, a Load Serving Entity shall be allowed to transfer some or all of its Remaining Import Capability to any other Load Serving Entity or Market Participant. The ISO will accept transfers among

LSEs and Market Participants only to the extent such transfers are reported to the ISO by July 18, 2007 for RA Compliance Year 2008 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual through the ISO's Import Capability Transfer Registration Process by the entity receiving the Remaining Import Capability that sets forth (1) the name of the counter-parties, (2) the MW quantity, (3) term of transfer, and (4) price on a per MW basis. The CAISO will post to its website by August 8, 2007 for RA Compliance Year 2008 and for subsequent RA Compliance Years in accordance with the schedule set forth in the Business Practice Manual the information on transfers of Remaining Import Capability Received under this Step 8.

Step 9: Initial Scheduling Coordinator Request to Assign Remaining Import Capability by Branch Group: At any time up to and including July 19, 2007 for RA Compliance Year 2008 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, the Scheduling Coordinator for each Load Serving Entity or Market Participant shall notify the ISO of its request to assign its post-trading Remaining Import Capability on a MW basis per available branch group. Total requests for assignment of Remaining Import Capability by a Scheduling Coordinator cannot exceed the sum of the post-traded Remaining Import Capability of its Load Serving Entities. The ISO will honor the requests to the extent a branch group has not been over requested. If a branch group is over requested, the requests for Remaining Import Capability on that branch group will be assigned based on each Load Serving Entity's Import Capability Load Share Ration in the same manner as set forth in Step 4. A Market Participant without an Import Capability Load Share will be assigned the Import Capability Load Share equal to the average Import Capability Load Share of those Load Serving Entities from which it received transfers of Remaining Import Capability.

Step 10: ISO Notification of Initial Remaining Import Capability Assignments and Unassigned Capability: At any time up to and including July 27, 2007 for RA Compliance Year 2008 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, the ISO will:

a. Notify the Scheduling Coordinator for each Load Serving Entity or Market Participant of the Load Serving Entity or Market Participant's accepted request(s) for assigning Remaining Import Capability under Step 9; and

b. Publish on its website aggregate unassigned Available Import Capability, if any, the identity of the branch groups with unassigned Available Import Capability, and the MW quantity of Available Import Capability, on each such branch group.

Step 11: <u>Secondary Scheduling Coordinator Request to Assign Remaining Import Capability by Branch Group</u>: To the extent Remaining Import Capability remains unassigned as disclosed by Step 10, at any time up to and including August 1, 2007 for RA Compliance Year 2008 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, Scheduling Coordinators for Load Serving Entities or Market Participants shall notify the ISO of their requests to assign any remaining Remaining Import Capability on a MW per available branch group basis. The ISO will honor the requests to the extent a branch group has not been over requested. If a branch group is over requested, the requests on that branch group will be assigned based on each Load Serving Entity or Market Participant's Import Capability Load Share Ratio, as used in Steps 4 and 9.

Step 12: <u>Notification of Secondary Remaining Import Capability Assignments and Unassigned Capability</u>: At any time up to and including August 8, 2007 for RA Compliance Year 2008 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, the ISO will:

a. Notify the Scheduling Coordinator for each Load Serving Entity or Market Participant of the Load Serving Entity or Market Participant's accepted request(s) for assigning Remaining Import Capability under Step 11; and

b. Publish on its website unassigned aggregate Available Import Capability, if any, the identity of the branch groups with Available Remaining Import Capability, and the MW quantity of Availability Import Capability on each such branch group.

Step 13: Requests for Balance of Year Unassigned Available Import Capability: To the extent total Available Import Capability remains unassigned as disclosed by Step 12, Scheduling Coordinators for Load Serving Entities or Market Participants shall notify the ISO at any time, except as limited herein, of a request for unassigned Available Import Capability on a specific branch group on a per MW basis. Each request must include the identity of Load Serving Entity or Market Participant on whose behalf the request is made. The ISO will accept only two (2) requests per calendar week from any Scheduling Coordinator on behalf of a single Load Serving Entity or other Market Participant. The ISO will honor requests in priority of the time requests from Scheduling Coordinators were received until the branch group is fully assigned and without regard to any Load Serving Entity's Load Share Quantity. Any honored request shall be for the remainder of the RA Compliance Year; however, any notification by the ISO of acceptance of the request in accordance with this Section after the 20th calendar day of any month shall not be permitted to be included in the Load Serving Entity's Resource Adequacy Plan submitted in the same month as the acceptance.

The ISO shall provide an electronic means, either through the Import Capability Transfer Registration Process or otherwise, of notifying the Scheduling Coordinator of the time the request was deemed received by the ISO and, within seven (7) days of receipt of the request, whether the request was honored. If honored, it shall be the responsibility of the Scheduling Coordinator and its Load Serving Entity to notify the CPUC or applicable Local Regulatory Authority of the acceptance of the request for unassigned import capability. If the request is not honored because the branch group requested was fully assigned, the request will be deemed rejected and the Scheduling Coordinator, if it still seeks to obtain unassigned Available Import Capability, will be required to submit a new request for unassigned import capability on a different branch group. For RA Compliance Year 2008, the ISO will update on its website the list of unassigned capability by branch group on or before the 5th calendar day of each month and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual.

This multi-step process for assignment of Total Import Capability does not guarantee or result in any actual transmission service being assigned and is only used for determining the import capability that can be credited towards satisfying the Planning Reserve Margin of a Load Serving Entity under this Section 40. Upon the request of the ISO, Scheduling Coordinators must provide the ISO with information on Pre-RA Import Commitments and any transfers or sales of assigned Total Import Capability. To the extent that the ISO's review of Resource Adequacy Plans identifies reliance upon Total Import Capability that exceeds the Total Import Capability assigned to the Load Serving Entity under this section, the ISO will inform the CPUC or appropriate Local Regulatory Authority, as appropriate.

40.5.2.2.2 Bilateral Import Capability Transfers and Registration Process

40.5.2.2.2.1 Eligibility Registration for Bilateral Import Capability Transfers

To be eligible to engage in any bilateral assignment, sale, or other transfer of Remaining Import Capability under Step 8 of Section 40.5.2.2.1 or Section 40.5.2.2.2.2 or Existing Contract Import Capability, and Pre-RA Import Commitment Capability under Section 40.5.2.2.2.2, a Load Serving Entity or other Market Participant must provide the ISO through the Import Capability Transfer Registration Process the following information:

a. Name of the Load Serving Entity or Market Participant

b. E-mail contact information

For RA Compliance Year 2008, beginning in July 2007, the ISO will post to its website the information received under this Section on a monthly basis on or before the 5th calendar day of each month and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual. Any assignment, sale, or other transfer of Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability may only be made by or to a Load Serving Entity or Market Participant whose information received under this Section has been posted to the ISO website prior to the date of the assignment sale or other transfer of the Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability. It shall be the exclusive responsibility of the Load Serving Entity or Market Participant to ensure that the information posted to the ISO website under this Section is accurate and up to date.

40.5.2.2.2.2 Reporting Process for Bilateral Import Capability Transfers

This Section shall apply to all transfers of Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability other than that provided for in Step 8 of Section 40.5.2.2.1. Any Load Serving Entity or other Market Participant that has obtained Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability may assign, sell, or otherwise transfer such Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability in MW increments. The import capability subject to each transfer shall remain on the branch group assigned pursuant to Section 40.5.2.2.1.

The Scheduling Coordinator for the Load Serving Entity or Market Participant receiving the transferred Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability must report the transfer to the ISO through the ISO's Import Capability Transfer Registration Process by providing the following information:

a. Identity of the counter-party(ies);

b. The MW quantity;

c. The branch group on which the Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability was assigned;

d. The term of the transfer;

e. Price on a per MW basis; and

f. Whether the import capability assignment being transferred is Existing Contract Import Capability, Per-RA Import Commitment Capability, or Remaining Import Capability.

The ISO will promptly post to its website the information on transfers of received under the Section except for the information received pursuant to subpart f of this section. On a quarterly basis, the ISO shall also report to FERC the transfer information received under this Section and Step 8 of Section 40.5.2.2.1. Transfer information received in accordance with this Section after the 20th calendar day of any month shall not be permitted to be included in the Load Serving Entity's Resource Adequacy Plan submitted in the same month as the transfer submission.

40.5.2.2.2.3 Other Import Capability Information Postings

For RA Compliance Year 2008, beginning in September 2007, the ISO will post to its website on a monthly basis on or before the 5th calendar day of each month and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, for each branch group, the holder and that holder's quantity in MW of import capability assigned on the particular branch group as of the reporting date.

The ISO will also post to its website following submission of the annual Resource Adequacy Plans under Sections 40.2.1.1, 40.2.2.4, 40.2.3.4, and 40.2.4, for each branch group, by a "yes" or "no" designation, whether each holder of import capability assigned on the particular branch group has fully included the assigned import capability in the holder's annual Resource Adequacy Plans.

40.6 Submission of Supply Plans.

Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity shall provide the ISO with annual and monthly Supply Plans; however, Scheduling Coordinators for resources listed on schedule 14 of an MSS Agreement need not submit a Supply Plan, unless any capacity from such Schedule 14 resources has been sold to any Load Serving Entity other than the MSS Operator that owns or controls the resource. The annual Supply Plan shall be provided by September 30th of each year. The monthly Supply Plan shall be provided on the last business day of the second month prior to the compliance month (e.g., March 31 for May). Both the annual and monthly Supply Plans shall be provided in the form set forth on the ISO's Website, listing their commitments to provide Resource Adequacy Capacity to any Load Serving Entity or Entities for the reporting period.

40.6.1 Compliance with Supply Plan Obligation.

Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity that fail to provide the ISO with annual or monthly Supply Plans as set forth in this ISO Tariff shall be subject to Section 37.6.1 of the ISO Tariff.

40.6A Availability of Resource Adequacy Resources.

40.6A.1 Applicability.

The requirements of Section 40.6A shall apply to all Resource Adequacy Resources identified on the Resource Adequacy Plans submitted by Scheduling Coordinators for Load Serving Entities serving Load in the ISO Control Area other than Resource Adequacy Resources identified exclusively on the Resource Adequacy Plans of (i) Load Serving Entities that have entered into a Metered Subsystem Agreement with the ISO and (ii) the State Water Project.

40.6A.2 Available Generation.

For the purposes of Section 40.6A, a Resource Adequacy Resources' "Available Generation" shall be: (a) the Resource Adequacy Capacity of a Generating Unit, other than a Hydroelectric facility or a QF that is still under a power purchase agreement with a host utility, System Unit that has contracted to supply Resource Adequacy Capacity to a non-MSS Load Serving Entity serving Load with the ISO Control Area, adjusted for any outages or reductions in capacity reported to the ISO in accordance with this ISO Tariff, (b) minus the unit's scheduled operating level as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the unit committed to deliver Energy or provide Operating Reserve to the Resource Adequacy Resources' Generator's Native Load.

In the case where the Resource Adequacy Resource is a System Resource, and to the extent the CPUC or other Local Regulatory Authority has imposed an obligation that System Resources relied upon by Load Serving Entities within their jurisdiction to meet Resource Adequacy requirements must be available to the ISO, the Available Generation of the System Resource shall be the Resource Adequacy Capacity of the System Resource adjusted for any outages or reductions in capacity reported to the ISO in accordance with this ISO Tariff, (b) minus the total amount of the System Resource's actual energy scheduled on the specific intertie of the import Resource Adequacy Capacity as identified in the ISO's Final Hour-Ahead Schedules, and (c) minus the amount of the System Resource's commitments on the specific intertie of the import Resource Adequacy Capacity to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator. The Available Generation of the System Resource shall never be less than zero.

40.6A.3 Reporting Requirements for Non-Participating Generators.

So that the ISO may determine the Available Generation of Resource Adequacy Resources, Resource Adequacy Resources, other than non-resource specific System Resources and Qualifying Facilities ("QFs") with effective contracts under the Public Utilities Regulatory Policies Act, that are not Participating Generators shall be required to file with the ISO: (i) the Generating Unit's minimum operating level; (ii) the Generating Unit's maximum operating level; and (iii) the Generating Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch Resource Adequacy Resources In addition, Resource Adequacy Resources that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 40.6A, notify the ISO, as soon as practicable, of any Planned Maintenance Outages, Forced Outages (per the requirements set forth in Section 9.3.10.2), Uncontrollable Force event Outages or any other reductions in their maximum operating levels or Resource Adequacy Capacity during the relevant month.

40.6A.4 Obligation to Offer Available Capacity.

Except as set forth in Sections 40.6A.5 and 40.6A.6, all Resource Adequacy Resources shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 40.6A.2 and any other Available Generation beyond its Resource Adequacy Capacity shall be subject to the FERC must-offer obligation as set forth in Section 40.7. The Resource Adequacy Resource shall make available to the ISO Real Time Market all Resource Adequacy Capacity that is not subject to an outage or is otherwise participating in the ISO Market or included on a self-schedule. Notwithstanding the foregoing, a Resource Adequacy Resource that is a Participating Intermittent Resource satisfies its obligation to offer Available Generation under this Section by scheduling in accordance with Appendix Q of the ISO Tariff.

40.6A.5 Submission of Bids and Applicability of the Proxy Price.

For each Operating Hour, the Scheduling Coordinator for the Resource Adequacy Resource shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 34.2. In addition, the ISO shall calculate for each gas-fired Resource Adequacy Resource (other than gas-fired Resource Adequacy Resources which are also System Resources), in accordance with Section 40.10.1, a Proxy Price for Energy.

If a Scheduling Coordinator for the Resource Adequacy Resource fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the un-bid quantity of the Resource Adequacy Resource's Available Generation will be deemed by the ISO to be bid at the Resource Adequacy Resource's Proxy Price if (i) the Resource Adequacy Resource is a gas-fired Generating Unit and (ii) the Resource Adequacy Resource has provided the ISO with adequate data in compliance with Section 40.6A.3 for the applicable Generating Unit. For all other Resource Adequacy Resources that are Generating Units, the un-bid quantity of the Resource Adequacy Resources' Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order the ISO will insert this un-bid quantity into the Resource Adequacy Resource's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the Resource Adequacy Resources' Available Generation.

40.6A.6 Resource Adequacy Resource Obligation Process.

Resource Adequacy Resources may seek a waiver of the obligation to offer all Available Generation, as set forth in Section 40.6A.4 of this ISO Tariff, for one or more of their units. All Resource Adequacy Resources obligated under their respective Resource Adequacy Plans that have not submitted Day-Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all Available Generation. If conditions permit, the ISO may, at its sole discretion, grant waivers and allow a Resource Adequacy Resource to remove one or more Generating Units from service and, in doing so, the ISO will first grant waivers to FERC Must-Offer Generators, on a non-discriminatory basis, that are not also Resource Adequacy Resources, and then, if permissible, the ISO may grant waivers to Resource Adequacy Resources or resources designated as RCST on a non-discriminatory basis.

The hours for which waivers are not granted shall constitute Waiver Denial Periods. A Waiver Denial Period shall be extended as necessary to accommodate the unit minimum up and down times. Units shall be on-line in real time during Waiver Denial Periods, or they will be in violation of the availability. Exceptions shall be allowed for verified forced outages or as otherwise set forth in Section 40.6A.5. The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). To the extent conditions permit, the ISO will revoke the waivers of Resource Adequacy Resources and RCST resources prior to revoking the waivers of FERC Must-Offer Generators. The ISO shall inform a Resource Adequacy Resource that its Waiver request has been approved, disapproved or revoked, and shall provide the Resource Adequacy Resource with the reason(s) for the decision, which reasons shall be non-discriminatory apart from the status of whether the unit is a Resource Adequacy Resource. The ISO will: (1) notify Resource Adequacy Resources of the ISO decisions on pending Waiver requests received no later than 10:00 a.m. (beginning of Hour Ending 11) no later than 11:30 a.m. (middle of Hour Ending 12) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m. on the following day, notify Resource

Adequacy Resources of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m. (beginning of Hour Ending 11) on the day before; (3) end Waiver Denial Periods at any time; (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to the time a unit would be required to be on-line generating at its Pmin; and (5) revoke a waiver denial for a Short-Start Resource Adequacy Resource at any time and such revocation will be communicated via a ISO real-time dispatch or unit commitment instruction.

40.6A.7 Penalties for Non-Compliance.

In addition to any other penalty or settlement consequence of a failure of a unit to operate in accordance with a ISO operating order, the failure of a Scheduling Coordinator for a Resource Adequacy Resource to make the Resource Adequacy Resource available to the ISO in accordance with the requirements of Section 40 of this ISO Tariff or to operate the Resource Adequacy Resource by placing it online or in a manner consistent with a submitted Supplemental Energy bid or Proxy Price Energy Bid shall result in that Scheduling Coordinator being subject to the sanctions set forth in Section 37.2 of the ISO Tariff.

40.6B Recovery of Minimum Load Costs By Resource Adequacy Resources.

40.6B.1 Eligibility.

Except as set forth below, Resource Adequacy Resources that are Generating Units and System Units for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity shall be eligible to recover Un-Recovered Minimum Load Costs during Waiver Denial Periods. Units from Resource Adequacy Resources that incur Minimum Load Costs during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Resource Adequacy Resource has a Final Hour-Ahead Energy Schedule, the Resource Adequacy Resource shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a Resource Adequacy Resource generating at minimum load in compliance with the supply obligation, produces a quantity of Energy that varies from its minimum operating level by more than the Tolerance Band, the Resource Adequacy Resource shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a Resource Adequacy Resource produces a quantity of

Energy above minimum load due to an ISO Dispatch Instruction, the Resource Adequacy Resource shall recover its Un-Recovered Minimum Load Costs as set forth in this Section and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible Resource Adequacy Resource for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from Resource Adequacy Resources that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) To the extent the Instructed Imbalance Energy payments are not sufficient to cover the generator's Minimum Load Cost as defined in Section 40.6B.3 of this ISO Tariff, the generator will also receive an uplift payment for its Un-Recovered Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the unit runs at minimum load in compliance with the Resource Adequacy offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

40.6B.2 Payments for Imbalance Energy above the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

When, on a Settlement Interval basis, a Resource Adequacy Resource's Generating Unit or System Units for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity produces a quantity of Energy above the unit's minimum operating level due to an ISO Dispatch Instruction, the Resource Adequacy Resource shall recover Un-Recovered Minimum Load Costs as set forth in Section 40.6B.1 and its bid costs, based on the ISO's instruction, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band.

40.6B.3 Payments for Imbalance Energy for the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

Resource Adequacy Resources operating at or near its operating level during a Waiver Denial Period either: (1) without a forward Schedule for its minimum operating level Energy or (2) with a Schedule to a special-purpose Demand ID for the sole purpose of Scheduling the minimum operating level Energy shall be paid its Un-Recovered Minimum Load Costs subject to eligibility as set forth in Section 40.6B.1 and not be paid an additional amount by the ISO for Energy actually delivered.

40.6B.4 Un-Recovered Minimum Load Costs.

The Un-Recovered Minimum Load Costs for each hour of Waiver Denial Period shall be calculated as the difference between: (1) a resource's Minimum Load Costs as calculated in this Section for the same Settlement Interval and (2) the Imbalance Energy payment for a resource's minimum load energy in the Settlement Interval. If the Imbalance Energy payment for minimum load energy exceeds the Minimum Load Costs, then there are no Un-Recovered Minimum Load Costs. The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: (1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.10) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Resource Adequacy Resource is not served from one of those three Service Areas; and (2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

40.6B.5 Allocation of Un-Recovered Minimum Load Costs.

For each Settlement Interval, the ISO shall determine whether the Un-Recovered Minimum Load Costs for

Resource Adequacy Resources, as applicable, for each unit operating during a Waiver Denial Period are due to (1) local reliability requirements, (2) zonal reliability requirements, or (3) ISO Control Area-wide reliability requirements pursuant to Section 40.6B.5.1. On a monthly basis, the ISO shall sum the Un-Recovered Minimum Load Costs and shall allocate those costs as follows:

(1) if the Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity was operating to meet local reliability requirements, the cost shall be allocated to the Participating TO in whose PTO Service Territory the unit is located, or, where the unit is located outside the PTO Service Territory of any Participating TO, to the Participating TO or Participating TOs whose PTO Service Territory or Territories are contiguous to the Service Area in which the Generating Unit or System Unit is located, in proportion to the benefits that each such Participating TO receives, as determined by the ISO. Where the costs allocated under this section are allocated to two or more Participating TOs, the ISO shall file the allocation under Section 205 of the Federal Power Act. Costs allocated under this part (1) shall be considered Reliability Services Costs.

(2) if the Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity was operating to meet zonal reliability requirements, the Un-Recovered Minimum Load Costs shall be allocated on a monthly basis to each Scheduling Coordinator in the constrained Zone based on the ratio of that Scheduling Coordinator's monthly Demand to the sum of all Scheduling Coordinators' monthly Demand in that Zone;

(3) if the Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity was operating to meet ISO Control Area-wide reliability requirements, the ISO shall allocate the Un-Recovered Minimum Load Costs in the following way:

a. first, to the monthly absolute total of all Net Negative Uninstructed Deviation (determined for each Settlement Interval based on Final Hour-Ahead Schedules) at a per-MWh rate that shall not exceed a figure that is determined by dividing the total Un-Recovered Minimum Load Cost in that month by the sum of the minimum loads for Generating Units operating under Waiver Denial Periods in that month;

b. finally, all remaining costs not allocated per (a) shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's monthly Control Area Gross Load and Demand within California outside the ISO Control Area that is served by exports to the monthly sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators, except that Demand outside the ISO Control Area that is served by exports that are scheduled as part of a Wheeling Through transaction shall be excluded from the calculation of such allocations.

40.6B.5.1 Criteria for Allocation of Un-Recovered Minimum Load Costs

The ISO shall use the following criteria for determining whether a Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity falls within the local reliability, zonal reliability, or ISO Control Area-wide reliability categories for allocation of Un-Recovered Minimum Load Costs.

40.6B.5.1.1 Local Reliability Requirements

The ISO shall classify a Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity as committed or operated for local reliability requirements when it is committed or operating to:

(1) maintain power flows on a transmission component that is not part of a transmission path between Congestion Zones;

(2) maintain acceptable voltage levels at a network location that is not part of a transmission path between Congestion Zones; or

(3) accommodate the forced or scheduled outage of a network component that is not part of a transmission path between Congestion Zones.

40.6B.5.1.2 Zonal Reliability Requirements

The ISO shall classify a Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity as committed or operated for zonal reliability requirements when it is committed or operating to:

(1) maintain operations within the requirements of any nomogram that governs the operations of an Inter-Zonal Interface;

(2) maintain power flows on a transmission line that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface;

(3) maintain acceptable voltage levels at a location that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface; or

(4) accommodate the forced or scheduled outage of a network component that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface.

40.6B.5.1.3 ISO Control Area-wide Reliability Requirements

The ISO shall classify a Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity as committed or operated for ISO Control Area-wide reliability requirements when it is committed or operating to meet forecast Control Area Demand.

40.6B.5.1.4 Incremental Cost of Local

Beginning October 1, 2004, when a Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity is committed for local reliability requirements, and that unit also meets an overall ISO Control Area-wide need, the ISO shall allocate only the incremental cost of committing that unit above the cost of committing the least-cost unit that would have been committed to resolve the ISO Control Area-wide reliability need absent the local reliability need, to the Participating TO.

40.6B.6 Payment of Available Capacity under the Resource Adequacy Obligation.

Available Generation of Resource Adequacy Resources that is required to be offered to the Real Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Un-Recovered Minimum Load Cost compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period that the unit generated above minimum load in compliance with ISO Dispatch Instructions.

40.7 FERC Must-Offer Obligations.

40.7.1 Applicability.

The requirements of Section 40.7 shall apply to (a) all Participating Generators, and (b) all persons, regardless of whether the person is a "public utility" as defined in Section 201 of the Federal Power Act, that own or control one or more non-hydroelectric Generating Units or System Units or System Resources located in California from which energy or capacity is either: (i) sold through any market operated by the ISO, or (ii) transmitted over the ISO Controlled Grid. Each person described in this Section 40.7.1 is referred to in the ISO Tariff as a "FERC Must-Offer Generator.", provided that such person with Eligible Capacity designated as RCST shall not be considered a FERC Must-Offer Generator to the extent, and for the term, of the RCST designation. The requirements of this Section 40.7 shall apply to all non-hydroelectric Generating Units located in California that are owned or controlled by a FERC Must-Offer Generator.

40.7.2 Available Generation.

For the purposes of Section 40.7, a FERC Must-Offer Generator's "Available Generation" from a non-hydroelectric Generating Unit shall be: (a) the Generating Unit's maximum operating level adjusted for any outages or reductions in capacity reported to the ISO in accordance with Section 9.3.9 or 40.7.3 and for any limitations on the Generating Unit's operation under applicable law, including contractual obligations, which shall be reported to the ISO, (b) minus the Generating Unit's scheduled operating level as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the Generating Unit's or System Unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the FERC Must-Offer Generator's Native Load.

40.7.3 Reporting Requirements for Non-Participating Generators.

So that the ISO may determine the Available Generation of all FERC Must-Offer Generators, FERC Must-Offer Generators that are not Participating Generators shall be required to file with the ISO, for each non-hydroelectric Generating Unit located in California they own or control: (i) the Generating Unit's minimum operating level; (ii) the Generating Unit's maximum operating level; and (iii) the Generating Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch FERC Must-Offer Generators. In addition, FERC Must-Offer Generators that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 40.7, notify the ISO, as soon as practicable, of any Planned Maintenance Outages, Forced Outages, Force Majeure Event outages or any other reductions in their maximum operating levels or Resource Adequacy Capacity during the relevant month.

40.7.4 Obligation To Offer Available Generation.

Except as set forth in Sections 40.7.5 and 40.7.6, all FERC Must-Offer Generators shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 40.7.2.

40.7.5 Submission of Bids and Applicability of the Proxy Price.

For each Operating Hour, FERC Must-Offer Generators shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 34.2. In addition, the ISO shall calculate for each gas-fired FERC Must-Offer Generator, in accordance with Section 40.10.1, a Proxy Price for Energy.

If a FERC Must-Offer Generator fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the unbid quantity of the FERC Must-Offer Generator's Available Generation will be deemed by the ISO to be bid at the FERC Must-Offer Generator's Proxy Price for that hour if: (i) the applicable Generating Unit is a gas-fired unit and (ii) the FERC Must-Offer Generator has provided the ISO with adequate data in compliance with Sections 40.7.7 and 40.7.3 for the applicable Generating Unit. For all other Generating Units owned or controlled by a FERC Must-Offer Generator, the unbid quantity of the FERC Must-Offer Generator's Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order, the ISO will insert this unbid quantity into the FERC Must-Offer Generator's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the FERC Must-Offer Generator's Available Generation.

40.7.6 FERC Must-Offer Obligation Process.

FERC Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 40.7.4 of this ISO Tariff, for one or more of their Generating Units or System Units.

All FERC Must-Offer Generators obligated under the must-offer obligation that have not submitted Day-

Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all Available Generation. If conditions permit, the ISO may, at its sole discretion, grant waivers and allow a FERC Must-Offer Generator to remove one or more Generating Units or System Units from service. In doing so, the ISO will first grant waivers to FERC Must-Offer Generators, on a non-discriminatory basis, that are not also Resource Adequacy Resources and then, if permissible, the ISO may grant waivers to Resource Adequacy Resources or resources designated as RCST on a non-discriminatory basis.

The hours for which waivers are not granted shall constitute Waiver Denial Periods. A Waiver Denial Period shall be extended as necessary to accommodate Generating Unit minimum up and down times. Generating Units shall be on-line in real time during Waiver Denial Periods, or they will be in violation of the must-offer obligation. Exceptions shall be allowed for verified forced outages. The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). To the extent conditions permit, the ISO will revoke the waivers of Resource Adequacy Resources and RCST resources prior to revoking the waivers of other FERC Must-Offer Generators. The ISO shall inform a FERC Must-Offer Generator that its Waiver request has been approved, disapproved or revoked, and shall provide the FERC Must-Offer Generator with the reason(s) for the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify FERC Must-Offer Generators of the ISO decisions on pending Waiver requests received no later than 10:00 a.m. (beginning of Hour Ending 11) no later than 11:30 a.m. (middle of Hour Ending 12) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m. on the following day, notify FERC Must-Offer Generators of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m. (beginning of Hour Ending 11) on the day before; (3) end Waiver Denial Periods at any time; and (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to the time a unit would be required to be on-line generating at its Pmin.

40.8 Recovery of Minimum Load Costs By FERC Must-Offer Generators.

40.8.1 Eligibility.

Except as set forth below, Generating Units shall be eligible to recover Minimum Load Costs during

Waiver Denial Periods. Units from FERC Must-Offer Generators that incur Minimum Load Costs during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a FERC Must-Offer Generator has a Final Hour-Ahead Energy Schedule, the FERC Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a FERC Must-Offer Generator generating at minimum operating level in compliance with the must-offer obligation, produces a quantity of Energy that varies from its minimum operating level by more than the Tolerance Band, the FERC Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a FERC Must-Offer Generator's resource produces a quantity of Energy above minimum load due to an ISO Dispatch Instruction, the FERC Must-Offer Generator shall recover its Minimum Load Costs as set forth in this Section and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible FERC Must-Offer Generator for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from FERC Must-Offer Generators that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) The generator's Minimum Load Cost as defined in Section 40.8.4 of this ISO Tariff, the generator will also receive a payment for its Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

40.8.2 Payments for Imbalance Energy Above the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

When, on a Settlement Interval basis, a FERC Must-Offer Generator's Generating Unit produces a quantity of Energy above the Generating Unit's minimum operating level due to an ISO Dispatch Instruction, the FERC Must-Offer Generator shall recover Minimum Load Costs and its bid costs, based on the ISO's instruction, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band.

40.8.3 Payments for Imbalance Energy for the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

A Generating Unit operating at or near its minimum operating level during a Waiver Denial Period either (1) without a forward Schedule for its minimum operating level Energy or (2) with a Schedule to a special-purpose Demand ID for the sole purpose of Scheduling the minimum operating level Energy shall be paid, in addition to being paid its Minimum Load Costs subject to eligibility as set forth in Section 40.8.1, an amount equal to the Resource Specific Settlement Interval Ex Post Price times the amount of Energy actually delivered.

40.8.4 Minimum Load Costs.

The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: (1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.10) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the FERC Must-Offer Generator is not served from one of those three Service Areas; and (2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

40.8.5 [Not Used]

40.8.6 Allocation of Minimum Load Costs.

For each Settlement Interval, the ISO shall determine whether the Minimum Load Costs for each FERC Must Offer Generator unit operating during a Waiver Denial Period are due to (1) local reliability requirements, (2) zonal reliability requirements, or (3) ISO Control Area-wide reliability requirements pursuant to Section 40.8.6.1. On a monthly basis, the ISO shall sum the Settlement Interval Minimum Load Costs and shall allocate those costs as follows:

(1) if the Generating Unit was operating to meet local reliability requirements, the cost shall be allocated to the Participating TO in whose PTO Service Territory the Generating Unit is located, or, where the Generating Unit is located outside the PTO Service Territory of any Participating TO, to the Participating TO or Participating TOs whose PTO Service Territory or Territories are contiguous to the Service Area in which the Generating Unit is located, in proportion to the benefits that each such Participating TO receives, as determined by the ISO. Where the costs allocated under this section are allocated to two or more Participating TOs, the ISO shall file the allocation under Section 205 of the Federal Power Act. Costs allocated under this part (1) shall be considered Reliability Services Costs.

(2) if the Generating Unit was operating to meet zonal reliability requirements, the Minimum Load Costs shall be allocated on a monthly basis to each Scheduling Coordinator in the constrained Zone based on the ratio of that Scheduling Coordinator's monthly Demand to the sum of all Scheduling Coordinators' monthly Demand in that Zone;

(3) if the Generating Unit was operating to meet ISO Control Area-wide reliability requirements, the ISO shall allocate the Minimum Load Costs in the following way:

a. first, to the monthly absolute total of all Net Negative Uninstructed Deviation (determined for each Settlement Interval based on Final Hour-Ahead Schedules) at a per-MWh rate that shall not exceed a figure that is determined by dividing the total Minimum Load Cost in that month by the sum of the minimum loads for Generating Units operating under Waiver Denial Periods in that month;

b. finally, all remaining costs not allocated per (a) shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's monthly Control Area Gross Load and Demand within California outside the ISO Control Area that is served by exports to the monthly sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators, except that Demand outside the ISO Control Area that is served by exports that are scheduled as part of a Wheeling Through transaction shall be excluded from the calculation of such allocations.

40.8.6.1 FERC Must Offer Generator Unit Criteria for Allocation of Minimum Load Costs

The ISO shall use the following criteria for determining whether a FERC Must Offer Generator unit falls within the local reliability, zonal reliability or ISO Control Area-wide reliability categories for allocation of Minimum Load Costs.

40.8.6.1.1 Local Reliability Requirements

The ISO shall classify a FERC Must Offer Generator unit as committed or operated for local reliability requirements when it is committed or operating to:

(1) maintain power flows on a transmission component that is not part of a transmission path between Congestion Zones;

(2) maintain acceptable voltage levels at a network location that is not part of a transmission path between Congestion Zones; or

(3) accommodate the forced or scheduled outage of a network component that is not part of a transmission path between Congestion Zones.

40.8.6.1.2 Zonal Reliability Requirements

The ISO shall classify a FERC Must Offer Generator unit as committed or operated for zonal reliability requirements when it is committed or operating to:

(1) maintain operations within the requirements of any nomogram that governs the operations of an Inter-Zonal Interface;

(2) maintain power flows on a transmission line that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface;

(3) maintain acceptable voltage levels at a location that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface; or

(4) accommodate the forced or scheduled outage of a network component that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface.

40.8.6.1.3 ISO Control Area-wide Reliability Requirements

The ISO shall classify a FERC Must Offer Generator unit as committed or operated for ISO Control Area-wide reliability requirements when it is committed or operating to meet forecast Control Area Demand.

40.8.6.1.4 Incremental Cost of Local

Beginning October 1, 2004, when a FERC Must Offer Generator unit is committed for local reliability requirements, and that unit also meets an overall ISO Control Area-wide need, the ISO shall allocate only the incremental cost of committing that unit above the cost of committing the least-cost unit that would have been committed to resolve the ISO Control Area-wide reliability need absent the local reliability need, to the Participating TO.

40.8.7 Payment Of Available Generation Under The FERC Must-Offer Obligation.

Available Generation that is required to be offered to the Real-Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Minimum Load Cost compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period, as defined in Section 40.8.1, that the unit generated Energy above minimum operating level in compliance with ISO Dispatch Instructions.

40.9 Criteria for Issuing Must-Offer Waivers.

The ISO shall grant waivers so as to: (1) provide sufficient on-line generating capacity to meet operating reserve requirements; and (2) account for other physical operating constraints, including Generating Unit or System Unit minimum up and down times. Subject to the exceptions for Short Start Resource Adequacy Resources as identified in this ISO Tariff, the ISO shall grant, deny or revoke waivers using a security-constrained unit commitment software application to minimize start-up and Minimum Load Costs.

40.10 Requirement of FERC Must-Offer Generators to File Heat Rate and Emissions Rate Data.

Resource Adequacy Resources and FERC Must-Offer Generators, as defined in this ISO Tariff, that own or control gas-fired Generating Units or System Units must file with the ISO and the FERC, on a confidential basis, the heat rates and emissions rates for each gas-fired Generating Unit or System Unit that they own or control. Heat rate and emissions rate data shall be provided in the format specified by the ISO as posted on the ISO Website. Heat rate data provided to comply with this requirement shall not include start-up or minimum load fuel costs. Resource Adequacy Resources and FERC Must-Offer Generators must also file periodic updates of this data upon the direction of either FERC or the ISO. The ISO will treat the information provided to the ISO in accordance with this section as confidential and will apply the procedures in Section 20.4 of this ISO Tariff with regard to requests for disclosure of such information.

40.10.1 Calculation of the Proxy Price.

The ISO shall calculate each day separate Proxy Prices for each gas-fired Generating Unit or System Unit owned or controlled by a Resource Adequacy Resource or FERC Must-Offer Generator by applying the filed heat rates for those Generating Units or System Units to a daily proxy figure for natural gas costs with an additional $6.00/MWh allowed for operations and maintenance expenses. The proxy figures for natural gas costs shall be based on the most recent data available and shall be posted on the ISO Website by 8:00 AM on the day prior to which the figures will be used for calculation of the Proxy Price.

40.11 Emissions Costs.

40.11.1 Obligation to Pay Emissions Cost Charges.

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Emissions Costs incurred by a Resource Adequacy Resource or FERC Must-Offer Generator as a direct result of an ISO Dispatch Instruction, in accordance with this Section 40. The ISO shall levy this administrative charge (the "Emissions Cost Charge") each month, in two parts: 1) All Emission Costs attributed to minimum load Energy will be allocated to Scheduling Coordinators in proportion to and in a similar manner as each Scheduling Coordinator's Minimum Load Cost obligation per Section 40.8.6.1 or Un-Recovered Minimum Load Cost obligation under Section 40.6B.5.1. The amount of Emissions Costs attributed to minimum load Energy will be determined by dividing the total megawatt hours eligible for Minimum Load Cost compensation for the month by the total megawatt hours of Instructed Imbalance Energy for the month. The resulting percentage is then multiplied by the Emissions Cost Charges for the month to determine the Emission Costs attributed to minimum load Energy. The proportion of Emissions Costs to Minimum Load Costs will be determined by dividing the total Emissions Costs attributed to minimum load Energy for the month by the total Minimum Load Costs for the month. 2) All Emission Costs resulting from an ISO dispatch but not attributable to minimum load Energy will be allocated to all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Emissions Cost Charges in accordance with the ISO Payments Calendar.

40.11.2 Emissions Cost Trust Account.

All Emissions Cost Charges received by the ISO shall be deposited in the Emissions Cost Trust Account. The Emissions Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.

40.11.3 Emissions Cost Charge.

The amount the ISO will assess for the Emissions Cost Charge shall be the projected annual total of all Emissions Costs incurred by Resource Adequacy Resources and FERC Must-Offer Generators as a direct result of ISO Dispatch Instruction, adjusted for interest projected to be earned on the monies in the Emissions Cost Trust Account, divided by twelve (12) months. The initial amount for the Emissions Cost Charge, and all subsequent amounts for the Emissions Cost Charge, shall be posted on the ISO Website.

40.11.4 Adjustment of the Emissions Cost Charge.

The ISO may adjust the amount the ISO will assess for the Emissions Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between actual Emissions Cost Demand and projected Emissions Cost Demand;

(b) the difference, if any, between the projections of the Emissions Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions and the actual Emissions Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions as invoiced to the ISO and verified in accordance with this Section 40.11; and

(c) the difference, if any, between actual and projected interest earned on funds in the Emissions Cost Trust Account.

The adjusted amount the ISO will assess for the Emissions Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Website at least five (5) days in advance of the date on which the new amount shall be assessed.

40.11.5 Credits and Debits of Emissions Cost Charges Collected from Scheduling Coordinators.

In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Emissions Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

40.11.6 Submission of Emissions Cost Invoices.

Scheduling Coordinators for Resource Adequacy Resources or FERC Must-Offer Generators that incur Emissions Costs as a direct result of an ISO Dispatch Instruction may submit to the ISO an invoice in the form specified on the ISO Website (the "Emissions Cost Invoice") for the recovery of such Emissions Costs. Emissions Cost Invoices shall not include any Emissions Costs specified in an RMR Contract for a unit owned or controlled by a FERC Must-Offer Generator. All Emissions Cost Invoices must include a copy of all final invoice statements from air quality districts demonstrating the Emissions Costs incurred by the applicable Generating Unit or System Unit, and such other information as the ISO may reasonably require to verify the Emissions Costs incurred as a direct result of an ISO Dispatch Instruction.

40.11.7 Payment of Emissions Cost Invoices.

The ISO shall pay Scheduling Coordinators for all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction. If the Emissions Costs indicated in the applicable air quality districts' final invoice statements include emissions produced by operation not resulting from ISO Dispatch Instructions, the ISO shall pay an amount equal to Emissions Costs multiplied by the ratio of the MWh associated with ISO Dispatch Instruction to the total MWh associated with such Emissions Costs. The ISO shall pay Emissions Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Emissions Cost Trust Account. To the extent there are insufficient funds available in Emissions Cost Trust Account in any month to pay all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction, the ISO shall make pro rata payment of such Emissions Costs and shall adjust the rate at which the ISO will assess the Emissions Cost Charge in accordance with Section 40.11.4. Any outstanding Emissions Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Emissions Costs is limited to the obligation to pay Emissions Cost Charges received. All disputes concerning payment of Emissions Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

40.12 Start-Up Costs.

40.12.1 Obligation to Pay Start-Up Cost Charges.

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Start-Up Costs incurred by a Resource Adequacy Resource or FERC Must-Offer Generator as a direct result of an ISO Dispatch Instruction, in accordance with this Section 40.12. Such Start-Up Costs shall include (1) fuel and (2) auxiliary power. The ISO shall levy this charge (the "Start-Up Cost Charge"), each month, against all Scheduling Coordinators in proportion to and in a similar manner as each Scheduling Coordinator's Minimum Load Cost obligation under Section 40.8.6.1 or Un-Recovered Minimum Load Cost obligation under Section 40.6B.5.1. The proportion of Start-Up Costs to Minimum Load Costs will be determined by dividing the total Start-Up Cost Charge for the month by the total Minimum Load Costs for the month. The proportion of Start-Up Costs then will be multiplied by the individual Scheduling Coordinator's Minimum Load Costs for the month to determine the Scheduling Coordinator's Start-Up Cost Charge. Scheduling Coordinators shall make payment for all Start-Up Cost Charges in accordance with the ISO Payments Calendar.

40.12.2 Start-Up Cost Trust Account.

All Start-Up Cost Charges received by the ISO shall be deposited in the Start-Up Cost Trust Account. The Start-Up Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.

40.12.3 Start-Up Cost Charge.

The amount the ISO will assess for the Start-Up Cost Charge shall be the projected annual total of all Start-Up Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Instruction, adjusted for interest projected to be earned on the monies in the Start-Up Cost Trust Account, divided by twelve (12) months.

The initial amount for the Start-Up Cost Charge, and all subsequent amounts for the Start-Up Cost Charge, shall be posted on the ISO Website.

40.12.4 Adjustment of the Start-Up Cost Charge.

The ISO may adjust the amount the ISO will assess for the Start-Up Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between the projections of the Start-Up Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions and the actual Start-Up Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions as invoiced to the ISO and verified in accordance with this Section 40.12; and

(b) the difference, if any, between actual and projected interest earned on funds in the Start-Up Cost Trust Account.

The adjusted amount the ISO will assess for the Start-Up Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Website at least five (5) days in advance of the date on which the new amount shall be assessed.

40.12.5 Credits and Debits of Start-Up Cost Charges Collected from Scheduling Coordinators.

In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Start-Up Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

40.12.6 Submission of Start-Up Cost Invoices.

Scheduling Coordinators for Resource Adequacy Resources or FERC Must-Offer Generators that incur Start-Up Costs as a direct result of an ISO Dispatch Instruction or if the ISO revokes a waiver from compliance with the FERC must-offer obligation while the unit is off-line in accordance with Section 40.6A.6 or 40.7.6 of this ISO Tariff, and Scheduling Coordinators for Generating Units or System Units operating under Condition 2 of the relevant RMR Contract which are called out-of-market in accordance with Section 11.2.4.2 of this ISO Tariff may submit to the ISO an invoice in the form specified on the ISO Website (the "Start-Up Cost Invoice") for the recovery of such Start-Up Costs. Such Start-Up Costs shall not exceed the costs which would be incurred within the start-up time for a unit specified in Schedule 1 of the Participating Generator Agreement. Start-Up Cost Invoices shall use the applicable proxy figure for natural gas costs as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Resource Adequacy Resource or FERC Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas. Start-Up Cost Invoices shall specify the amount of auxiliary power used during the start-up and the actual price paid for that power. Start-Up Cost Invoices shall not include any Start-Up Costs specified in an RMR Contract for a unit owned or controlled by a FERC Must-Offer Generator.

40.12.7 Payment of Start-Up Cost Invoices.

The ISO shall pay Scheduling Coordinators for all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction. The ISO shall pay such Start-Up Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Start-Up Cost Trust Account. To the extent there are insufficient funds available in the Start-Up Cost Trust Account in any month to pay all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction, the ISO shall make pro rata payment of such Start-Up Costs and shall adjust the rate at which the ISO will assess the Start-Up Cost Charge in accordance with Section 40.12.4. Any outstanding Start-Up Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay

Start-Up Costs is limited to the obligation to pay Start-Up Cost Charges received. All disputes concerning payment of Start-Up Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

40.13 ISO Default Qualifying Capacity Criteria.

40.13.1 Applicability.

The criteria in Section 40.13 shall apply only where a Local Regulatory Authority does not establish criteria to determine the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity for such eligible resource types.

40.13.2 Nuclear and Thermal.

Nuclear and thermal units, other than Qualifying Facilities ("QFs") with effective contracts under the Public Utility Regulatory Policies Act addressed in Section 40.13.8 below, must be a Participating Generator or a System Unit. The Qualifying Capacity of nuclear and thermal units, other than Qualifying Facilities addressed in Section 40.13.8, will be based on net dependable capacity defined by North American Electric Reliability Council ("NERC") Generating Availability Data System ("GADS") information.

40.13.3 Hydro.

Hydro units, other than QFs with contracts under the Public Utility Regulatory Policies Act, must be either Participating Generators or System Units. The Qualifying Capacity of a pond or pumped storage hydro unit, other than a QF, will be determined based on net dependable capacity defined by NERC GADS minus variable head de-rate based on an average dry year reservoir level. The Qualifying Capacity of a pond or pumped storage hydro unit that is a QF will be determined based on historic performance during the Standard Offer 1 peak hours of noon to 6:00 p.m., using a three-year rolling average.

The Qualifying Capacity of all run-of-river hydro units, including QFs, will be based on net dependable capacity defined by NERC GADS minus an average dry year conveyance flow, stream flow, or canal head de-rate. As used in this section, average dry year reflects a one-in-five year dry hydro scenario (for example, using the 4th driest year from the last 20 years on record).

40.13.4 Unit-Specific Contracts.

Unit-specific contracts with Participating Generators or System Units will qualify as Resource Adequacy capacity subject to the verification that the total MW quantity of all contracts from a specific unit do not exceed the total Net Qualifying Capacity (MW) consistent with the Net Qualifying Capacity determination for that unit.

40.13.5 Contracts with Liquidated Damage Provisions.

Firm energy contracts with liquidated damages provisions, as generally reflected in Service Schedule C of the Western Systems Power Pool Agreement or the Firm LD product of the Edison Electric Institute pro forma agreement, or any other similar firm energy contract that does not require the seller to source the energy from a particular unit, and specifies a delivery point internal to the ISO Control Area entered into before October 27, 2005 shall be eligible to count as Qualifying Capacity until the end of 2008. A Scheduling Coordinator, however, cannot have more than 75% of its portfolio of Qualifying Capacity met by contracts with liquidated damage provisions for 2006. This percentage will be reduced to 50% for 2007 and 25% for 2008.

40.13.6 Wind and Solar.

As used in this Section, wind units are those wind Generating Units without backup sources of generation and solar units are those solar Generating Units without backup sources of generation. Wind and Solar units, other than QFs with effective contracts under the Public Utility Regulatory Policies Act, must be participants in the ISO's Participating Intermittent Resource Program ("PIRP").

The Qualifying Capacity of all wind or solar units, including QFs, will be based on their monthly historic performance during the Standard Offer 1 peak hours of noon to 6:00 p.m., using a three-year rolling average. New wind and solar generators which do not have three years of historic performance data will be assigned a default Qualifying Capacity for each year of the missing historical performance as follows: the Qualifying Capacity of another solar or wind generator with historic data located in the same weather regime with similar technology adjusted for the nameplate capacity ratio of the new generator and the similarly situated proxy generator. The supporting data and the sample Qualifying Capacity calculation will be submitted to the ISO for approval as part of the facilities PIRP program application.

The default Qualifying Capacity values will be replaced on a year by year basis with actual performance data as the data becomes available to form a three year rolling average.

40.13.7 Geothermal.

Geothermal units, other than QFs addressed in Section 40.13.8, must be Participating Generators or System Units. The Qualifying Capacity of geothermal units, other than QFs addressed in Section 40.13.8, will be based on NERC GAD net dependable capacity minus a de-rate for steam field degradation.

40.13.8 Treatment of Qualifying Capacity for QFs.

QFs must be Participating Generators (signed a Participating Generator or QF Participating Generator Agreement) or System Units, unless they have a PURPA contract. Except for hydro, wind, and solar QFs addressed pursuant to Sections 40.13.3 and 40.13.6 above, the Qualifying Capacity of QFs under PURPA contracts, will be based on historic monthly generation output during Standard Offer 1 peak hours of noon to 6:00 p.m. (net behind the meter loads) during a three-year rolling average.

40.13.9 Participating Load Resources.

The Qualifying Capacity of Participating Load shall be the average reduction in demand for over a three-year period on a per dispatch basis or, if the Participating Load does not have three years of performance history, based on comparable evaluation data using similar programs. Participating Load resources must be available at least 48 hours and if the Participating Load can only be dispatched for a maximum of two hours per event, than only 0.89% of a Scheduling Coordinator's portfolio may be made up of such Participating Load.

40.13.10 Jointly-Owned Facilities.

A jointly-owned facility must be either a Participating Generator or a System Unit. The Qualifying Capacity for the entire facility will be determined based on the type of resource as described elsewhere in this Section. In addition, the Scheduling Coordinator must provide the ISO with a demonstration of its entitlement to the output of the jointly-owned facility's Qualified Capacity and an explanation of how that entitlement may change if the facility's output is restricted.

40.13.11 Facilities Under Construction.

The Qualifying Capacity for facilities under construction will be determined based on the type of resource as described elsewhere in this Section. In addition, the facility must have been in commercial operation for no less than one month to be eligible to be included as a Resource Adequacy Resource in a Scheduling Coordinator's monthly plan.

40.13.12 System Resources.

40.13.12.1 Dynamically Scheduled System Resources.

Dynamically Scheduled System Resources shall be treated similar to resources within the ISO Control Area, except with respect to the deliverability screen under Section 40.5.2.1. However, eligibility as a Resource Adequacy Resource is contingent upon a showing by the Scheduling Coordinator that the Dynamically Scheduled System Resource has secured transmission through any intervening Control Areas for the operating hours that cannot be curtailed for economic reasons or bumped by higher priority transmission and that the Load Serving Entity upon which the Scheduling Coordinator is scheduling Demand has an allocation of import capacity at the import Scheduling Point under Section 40.5.2.2 of the ISO Tariff that is not less than the Resource Adequacy Capacity provided by the Dynamically Scheduled System Resource.

40.13.12.2 Non-Dynamically Scheduled System Resources.

For Non-Dynamically Scheduled System Resources, the Scheduling Coordinator must demonstrate that the Load Serving Entity upon which the Scheduling Coordinator is scheduling Demand has an allocation of import allocation at the import Scheduling Point under Section 40.5.2.2 of the ISO Tariff that is not less than the Resource Adequacy Capacity from the Non-Dynamically Scheduled System Resource. Eligibility as Resource Adequacy Capacity would be contingent upon a showing by the Scheduling Coordinator of the System Resource that it has secured transmission through any intervening Control Areas for the operating hours that cannot be curtailed for economic reasons or bumped by higher priority transmission. With respect to Non-Dynamically Scheduled System Resources, any inter-temporal constraints such as multi-hour run blocks, must be explicitly identified in the monthly Resource Adequacy Plan, and no constraints may be imposed beyond those explicitly stated in the plan.

40.14 Capacity Payments Under the FERC Must-Offer Obligation.

As set forth in this Section, Generating Units of FERC Must-Offer Generators that are eligible to recover Minimum Load Costs pursuant to Section 40.8 shall also be eligible to recover a Must-Offer Capacity Payment during Waiver Denial Periods, in addition to such Minimum Load Costs, provided the Generating Unit does not have an RMR contract, is not a Resource Adequacy Resource and is not designated as RCST. The Must-Offer Capacity Payment shall equal 1/17th of the Monthly RCST Charge as specified in Schedule 6 of Appendix F per megawatt for each day of the Waiver Denial Period, adjusted pro rata for any hours of that day in which the Generating Unit was ineligible for the recovery of Minimum Load Costs. For any Trading Day of a calendar month, if the sum of (i) total Must-Offer Capacity Payments that a FERC Must-Offer Generator has received for a Generating Unit under this Section 43.14 during that month, (ii) the total Imbalance Energy payments received when that Generating Unit is running at minimum load, and (iii) the Frequently Mitigated Adder under Section 34.1.2.1.1 during the calendar month, exceeds the Qualifying Capacity times the maximum Monthly RCST Charge (established in Schedule 6 of Appendix F) reduced by the Monthly PER (established in Schedule 6 of Appendix F), the FERC Must-Offer Generator shall not be eligible to receive Must-Offer Capacity Payments or the Frequently Mitigated Adder under Section 34.1.2.1.1 for that Generating Unit for that Trading Day, nor for any other Trading Day in the remainder of the calendar month (but shall continue to recover Minimum Load Costs and imbalance Energy payments). This Section 40.14 shall expire at midnight on the earlier of December 31, 2007 or the date immediately before the MRTU goes into effect.

40.14.1 Allocation of Must-Offer Capacity Payments

The ISO shall determine whether the Must-Offer Capacity Payment costs for each FERC Must-Offer Generator Generating Unit operating during a waiver denial period are due to (1) local reliability requirements, (2) zonal requirements, or (3) Control Area-wide requirements. For each month, the ISO shall sum the Must-Offer Capacity Payments costs and shall allocate those costs as follows:

(1) if the Generating Unit was operating to meet local reliability requirements, the Must-Offer Capacity Payment costs shall be considered incremental locational costs and shall be allocated in accordance with Section 40.8.6 (1).

(2) if the Generating Unit was operating due to Zonal requirements, the Must-Offer Capacity Payment costs shall be allocated in accordance with Section 40.8.6 (2)

(3) if the Generating Unit was operating to satisfy an ISO Control Area-wide need, the Must-Offer Capacity Payment costs shall be allocated in accordance with Section 40.8.6 (3).

40.15 Must-Offer Reporting Requirements

Sections 40.15 through 40.15.4 shall expire at midnight on the earlier of December 31, 2007 or the date immediately before the MRTU goes into effect.

40.15.1 Must-Offer Waiver Denial Report

The ISO shall publish a Must-Offer Waiver Denial Report ("MOWD Report") on the ISO Website on a weekly basis and shall provide a market notice of its availability. The MOWD Report shall indicate the category of the must-offer waiver denial, *i.e.,* local, zonal or system, and the amount of megawatts involved in each category. On a daily basis, thirty (30) days after the Trade Day, the ISO will publish on OASIS the allocation of Un-Recovered Minimum Load Costs for RCST and Resource Adequacy Resources and Minimum Load Costs for FERC Must-Offer Generators.

40.15.2 Monthly Minimum Load Cost Report

On a monthly basis, thirty (30) days after the Trade Day, the ISO will publish on ISO Website, the monthly allocation of Un-Recovered Minimum Load Costs for RCST and Resource Adequacy Resources, Minimum Load Costs for FERC Must-Offer Generators.

40.15.3 Multiple Denial of FERC Must-Offer Waivers

If the ISO issues a denial of must-offer waivers to a FERC Must-Offer Generator on four separate days in any calendar year, the ISO shall evaluate whether a Significant Event has occurred that warrants designation of the FERC Must-Offer Generator to provide service under the RCST ("MOWD Evaluation").

The ISO shall conduct a MOWD Evaluation after every four separate days on which the ISO denies a must-offer waiver request for such a FERC Must-Offer Generator.

40.15.4 Significant Event/Repeat Waiver Denial Report

The ISO shall publish the results of its assessment of the MOWD Evaluation ("Significant Event/Repeat MOWD Report"), including an explanation of its decision whether to designate FERC Must-Offer Generator capacity as RCST, on the ISO Website on a weekly basis unless no Significant Events or MOWD Evaluations occurred during the week. The ISO will provide a market notice of the availability of each Significant Event/Repeat MOWD Report. The Significant Event/Repeat MOWD Report shall explain why the ISO denied the must-offer waiver request that triggered the assessment of whether a Significant Event occurred, and whether any Resource Adequacy Resources, RMR units, or resources designated to provide service under the RCST were available and called upon by the ISO prior to its denial of the FERC Must-Offer Generator's must-offer waiver request. The ISO shall also explain why Non-Generation Solutions were insufficient to prevent the use of denials of must-offer waivers for local reasons. In the event that the ISO denies a must-offer waiver request for local or system reasons that do not constitute a Significant Event or is not due to a Resource Adequacy Resource non-performance, the report shall include an explanation for such issuance and shall be signed by the ISO's Vice President of Operations.

41 Procurement of RMR.

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

42.1 Generation Planning Reserve Criteria.

Generation planning reserve criteria shall be met as follows:

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

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

42.1.3 If the forecast shows that the applicable WECC/NERC Reliability Criteria cannot be met during peak Demand periods, then the ISO shall facilitate the development of market mechanisms to bring the ISO Controlled Grid during peak periods into compliance with the Applicable Reliability Criteria (or such more stringent criteria as the ISO may impose pursuant to Section 7.2.2.2). The ISO shall solicit bids for Replacement Reserve in the form of Ancillary Services, short-term Generation supply contracts of up to one (1) year with Generators, and Load curtailment contracts giving the ISO the right to reduce the Demands of those parties that win the contracts when there is insufficient Generation capacity to satisfy those Demands in addition to all other Demands. The curtailment contracts shall provide that the ISO's curtailment rights can only be exercised after all available Generation capacity has been fully utilized unless the exercise of such rights would allow the ISO to satisfy the Applicable Reliability Criteria at lower cost, and the curtailment rights shall not be exercised to stabilize or otherwise influence prices for power in the Energy markets.

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

42.1.5 Notwithstanding the foregoing, if the ISO concludes that it may be unable to comply with the Applicable Reliability Criteria, the ISO shall, acting in accordance with Good Utility Practice, take such steps as it considers to be necessary to ensure compliance, including the negotiation of contracts through processes other than competitive solicitations. The steps can include the negotiation of contracts for Ancillary Services on a real time basis. If the ISO is unable to obtain such Ancillary Services from within the ISO Controlled Grid, the ISO may solicit Ancillary Services from other Control Areas on a real-time basis.

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

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

42.1.8 Except where and to the extent that such costs are recovered from Scheduling Coordinators pursuant to Section 8, and except as provided in Section 42.1.9, all costs incurred by the ISO in any hour pursuant to any contract entered into under this Section 42.1 shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (including exports) bears to the total metered hourly Demand (including exports) served in that hour.

42.1.9 Costs incurred by the ISO pursuant to any contract entered into under this Section 42.1 for resources to meet any portion of the anticipated difference between forward schedules and the real-time deviations from those schedules shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator’s obligation for deviation Replacement

Reserve in the hour, determined in accordance with Section 8.12.3A bears to the total deviation Replacement Reserve in that hour.

43 Reliability Capacity Services Tariff

This section 43 of the ISO Tariff shall be referred to as the Reliability Capacity Services Tariff ("RCST"). The RCST as well as changes made to other Sections to implement the Offer of Settlement filed on March 31, 2006 in Docket No. EL05-146 (changes to Sections 34.1.2.1.1; 34.1.2.1.2; 40.6A.6; 40.7.1; 40.7.6; 40.14; 40.14.1; 40.15; 40.15.1; 40.15.2; 40.15.3; 40.15.4; Appendix F Schedule 6; and Appendix P, Attachment A) shall expire at midnight on the earlier of December 31, 2007 or the date immediately before the ISO's MRTU Tariff goes into effect, except that the provisions concerning compensation, cost allocation and settlement shall remain in effect until such time as RCST resources have been finally compensated for their services rendered under the RCST prior to the termination of the RCST, and the ISO has finally allocated and recovered the costs associated with such RCST compensation.

43.1 Designation

The ISO shall have the authority provided in this Section 43.1 to designate Eligible Capacity or System Resources to provide services under the RCST as set forth in this Section 43.

43.2 Local RCST Designations

The ISO may designate Eligible Capacity to provide services under the RCST to meet local reliability needs to the extent provided in this Section 43.2.

43.2.1 2007 Local RCST Designations

For 2007, the CPUC and Local Regulatory Authorities may establish Local Resource Adequacy Requirements for the RA Entities subject to their respective jurisdictions. Each Scheduling Coordinator for an RA Entity for which a Local Regulatory Authrority has elected to adopt a Local Resource Adequacy Requirement shall, within five (5) Business Days after FERC has issued an order approving the amendment to the ISO Tariff sumitted on December 15, 2006, inform the ISO in writing of the adoption of the Local Resource Adequacy Requirment and shall state in writing what the Local Resource Adequacy Requirment is; however if the information has already been provided to the ISO it does not have to be provided again to the ISO. In addition, the State Water Resources Development System, commonly known as the State Water Project of the California Department of Water Resources, shall be required to develop, in conjunction with the ISO, a program that ensures that it will not unduly rely on the local resource procurement practices of other Load Serving Entities. Scheduling Coordinators for RA Entities, in accordance with any requirements of the CPUC or

Local Regulatory Authorities, as applicable, shall submit to the ISO a Local Resource Adequacy Demonstration listing the Qualifying Capacity that they will make available to the ISO for purposes of satisfying any Local Resource Adequacy Requirement applicable to them in 2007. Such Qualifying Capacity must be made available to the ISO in accordance with Section 40.6A.

43.2.1.1 2007 Local Resource Adequacy Demonstrations

All Scheduling Coordinators for RA Entities that are subject to a Local Resource Adequacy Requirement shall submit their Local Resource Adequacy Demonstrations to the ISO pursuant to this Section 43.2.1 within five (5) Business Days after FERC has issued an order approving the amendment to the ISO Tariff submitted on December 15, 2006, unless the RA Entity, through its Scheduling Coordinator or its Local Regulatory Authority, has previously identified the Qualifying Capacity that the RA Entity will make available to the ISO for purposes of satisfying any Local Resource Adequacy Requirement applicable to them in 2007 in an Annual Resource Adequacy Plan submitted pursuant to Section 40.2.1.

43.2.1.2 2007 Local Resource Adequacy Demonstration Evaluations

The ISO shall compare the submitted Local Resource Adequacy Demonstrations and Annual Resource Adequacy Plans submitted pursuant to Section 40.2.1 with any applicable Local Resource Adequacy Requirement to determine whether there is any Local Resource Adequacy Requirement Deficiency in any 2007 Local Reliability Area. Within fifteen (15) Business Days after FERC has issued an order approving the amendment to the ISO Tariff submitted on December 15, 2006, or sooner to the extent that the ISO has already received the information it requires with regard to a particular 2007 Local Reliability Area, and to the extent that a particular 2007 Local Reliability Area requirement has not been met, the ISO will issue to the Scheduling Coordinator for each RA Entity that the ISO identifies as deficient in meeting its Local Resource Adequacy Requirements, and to the applicable regulatory authority for such deficient RA Entity, the ISO's evaluation of the Local Resource Adequacy Demonstrations of such deficient RA Entity. The ISO's evaluation shall detail (1) the reasons why the ISO does not believe that the Local Resource Adequacy Demonstration and/or Annual Resource Adequacy Plan of such RA Entity satisfies a Local Resource Adequacy Requirement in any 2007 Local Reliability Area for such RA Entity, and (2) the amount of any aggregate Local Resource Adequacy Requirement Deficiency in a Local 2007 Local

Reliability Area in which the deficient RA Entity has a Local Resource Adequacy Requirement. Within five (5) Business Days of issuance of the ISO's evaluation, a Scheduling Coordinator shall notify the ISO whether it wishes to discuss with the ISO the ISO's assessment that a particular RA Entity for which it is the Scheduling Coordinator is deficient in meeting its Local Resource Adequacy Requirements. If the Scheduling Coordinator provides such notification, within (5) business days of the notification, the Scheduling Coordinator shall meet with the ISO and the RA Entity's applicable regulatory authority, if the regulatory authority so desires, to discuss the issue of whether a deficiency exists. Following such meeting, the ISO shall indicate whether or not there is a Local Resource Adequacy Requirement Deficiency for the RA Entity. Each Scheduling Coordinator for an RA Entity who has been notified of a deficiency by the ISO shall inform the ISO in writing within five (5) Business Days of the issuance of the ISO's evaluation, or within five (5) Business Days after the meeting to discuss the ISO's evaluation, whichever is applicable, whether the RA Entity intends to take steps to make up such deficiency, pursuant to any CPUC-established or Local Regulatory Authority-established opportunity to make up the deficiency, and the timing and nature of those steps. To the extent an RA Entity makes up such deficiency within the time allowed by the CPUC or Local Regulatory Authority, as appropriate, the Scheduling Coordinator for the RA Entity shall provide to the ISO information demonstrating that the deficiency has been made up.

43.2.1.3 2007 Local RCST Designations for Deficiencies

Following the ISO's identification of any Local Resource Adequacy Requirement Deficiency, and after the time for any consultation with the ISO and the CPUC-established or Local Regulatory Authority-established opportunity to make up such deficiency, the ISO may designate Eligible Capacity to provide services under the RCST consistent with the criteria set forth in Section 43.2.2. The ISO may designate Eligible Capacity to provide service under this Section 43.2.1 to the extent necessary to satisfy any remaining Local Resource Adequacy Deficiency only after: (i) RMR Units have been designated in the local area reliability study process for 2007, and (ii) the ISO has completed its evaluation of all Resource Adequacy Plans for 2007 and taken into account the effect of the resources identified in such plans (whether or not any of those resources are located in a 2007 Local Reliability Area). Designations of Eligible Capacity to provide services under the RCST made pursuant to this section shall have a term that commences on January 1, 2007, and expires on the earlier of midnight, December 31, 2007, or midnight on the day preceding the implementation of the Market Redesign & Technology Upgrade Tariff.

43.2.2 Selection of Eligible Capacity Designated for Local Reliability

The ISO will make designations of Eligible Capacity under Section 43.2 based on the lowest overall cost for each 2007 Local Reliability Area considering the following factors: the effectiveness of the Eligible Capacity, the quantity of Eligible Capacity of the resource relative to the remaining amount of capacity that is needed; and the Start-Up and Minimum Load Costs associated with the Eligible Capacity. The ISO shall have reasonable allowance to designate under the RCST an amount of Eligible Capacity from a Generating Unit that is slightly more or slightly less than a deficiency due to the quantity of Eligible Capacity from such Generating Unit that is available and suitable to meet the deficiency, consistent with the criteria in this section.

43.3 System RCST Designations

The ISO may designate Eligible Capacity for calendar years 2006 and 2007 to the extent provided in this Section 43.3.

43.3.1 Annual System Reliability Capacity Services Designations

No sooner than May 17, 2006, and following the ISO's review of the annual Resource Adequacy Plans submitted pursuant to Section 40.2.1 and, for 2007, any designation of Eligible Capacity pursuant to Section 43.2.1, the ISO may designate Eligible Capacity or System Resources to provide services under the RCST under this Section 43.3 to the extent necessary to cover the aggregate Year-Ahead System Resource Deficiency consistent with the criteria set forth in Section 43.3.3.

A designation of Eligible Capacity or System Resources to provide services under the RCST made pursuant to this Section 43.3.1 shall be for a minimum term of three months, provided that, at the discretion of the ISO, the designation term during 2006 may be extended to a maximum of the four summer months of June through September and, for 2007, the designation term during 2007 may be extended up to a maximum term of the five summer months of May through September.

43.3.2 Monthly System Reliability Capacity Services Designations

Following its review of the monthly Resource Adequacy Plans submitted by Scheduling Coordinators pursuant to Section 40.2.2, the ISO may designate Eligible Capacity or System Resources to provide services under the RCST under this Section 43.3 to the extent necessary to cover the aggregate Month-Ahead System Resource Deficiency consistent with the criteria set forth in Section 43.3.3.

Designations of Eligible Capacity or System Resources to provide services under the RCST made pursuant to this Section 43.3.2 shall be for the lesser of three months, the remainder of the calendar year or the period of time until the MRTU Tariff becomes effective.

43.3.3 Selection of Eligible Capacity Designated for System Reliability

The ISO will make designations of Eligible Capacity or System Resources under this Section 43.3 based on the following factors: the effectiveness of the Eligible Capacity in addressing local and/or zonal constraints in addition to meeting system needs; the quantity of Eligible Capacity of the resource; the Start-Up and Minimum Load Costs associated with the Eligible Capacity; and the effectiveness of the Eligible Capacity at reducing the Minimum Load Costs that might otherwise be incurred as a result of must-offer waiver denials. System Resources shall be subject to the ISO's established import limits as specified in accordance with Section 40.5.2.2. The ISO shall have reasonable allowance to designate under the RCST an amount of Eligible Capacity from a Generating Unit or System Resource that is slightly more or slightly less than a deficiency due to the quantity of Eligible Capacity from such Generating Unit or System Resource that is available and suitable to meet the deficiency, consistent with the criteria in this section.

43.4 RCST Designations For Significant Events

The ISO may designate Eligible Capacity or System Resources to provide service under this Section 43.4 following a Significant Event, and taking into account the expected duration of the Significant Event, if such an RCST designation is necessary to remedy any resulting material difference in ISO Controlled Grid operations relative to the assumptions reflected in the LARN Report for 2006 or relative to the assumptions underlying the CPUC's and, if applicable, a Local Regulatory Authority's development of Local Resource Adequacy Requirements for 2007. An RCST designation due to a Significant Event shall have a minimum term of three months and a maximum term up to the period of time which the ISO determines the Significant Event will remain in effect, provided that in no event shall the term of such RCST designation extend beyond the earlier of midnight on December 31, 2007 or midnight the day before the effective date of MRTU implementation. Any RCST designations under this section shall be in accordance with the criteria set forth in Section 43.3.3.

43.5 Obligations of a Resource Designated under the RCST

43.5.1 Must-Offer Obligations

Generating Units designated under the RCST shall be subject to all of the availability, must-offer, dispatch, testing, reporting, and verification obligations applicable to Resource Adequacy Resources identified in Resource Adequacy Plans under Section 40.6A of the ISO Tariff. Generating Units designated under the RCST must offer available capacity into the Ancillary Services markets to the extent capable.

43.5.2 Replacement Option

If a Generating Unit designated under the RCST is unavailable when issued a must-offer waiver denial by the ISO pursuant to Section 40.7.6 of the ISO Tariff, the Scheduling Coordinator for the resource may, within 2 hours for a must-offer waiver denial issued prior to the Hour-Ahead market and within 30 minutes for a must-offer waiver denial issued in Real-Time, substitute capacity from such Generating Unit with Eligible Capacity that: (i) is located at the same bus, or (ii) if not located at the same bus, is located in the same Local Reliability Area or 2007 Local Reliability Area, whichever is applicable, and which meets the ISO's effectiveness and operational needs, including size of resource, as determined by the ISO in its reasonable discretion. If the Scheduling Coordinator substitutes such Eligible Capacity, the Scheduling Coordinator must pay all additional Minimum Load Costs, Start-Up Costs, Emissions Costs (above the corresponding costs of the Generating Unit that is being substituted), and any bilateral contract costs incurred by the Scheduling Coordinator, as a result of the substitution. The actual Availability of the substitute resource will be used for the purposes of the calculations in Appendix F, Schedule 6.

43.5.3 Termination of Obligations

If a Participating Generator's Eligible Capacity is designated by the CAISO under the terms of the RCST, and the Participating Generator has not filed a notice to withdraw from the Participating Generator Agreement ("PGA"), then the Participating Generator shall be obligated to perform in accordance with the RCST for the term of the RCST designation. If a Participating Generator's Eligible Capacity is designated under the terms of the RCST after the Participating Generator has filed a notice to withdraw from its PGA, then the Participating Generator shall be obligated to perform in accordance with the RCST until the date that its PGA effectively terminates, but the Participating Generator shall be under no obligation to so perform after the effective date of the PGA termination. If a Participating Generator's Eligible Capacity is designated under the RCST after the Participating Generator has filed notice to withdraw from its PGA, and the Participating Generator agrees to provide service under the RCST, then the Participating Generator will enter into a PGA for the designated generating unit and invoice the ISO for any actual applicable restoration costs as provided in the RMR Service Agreement.

43.6 RCST Report

The ISO shall publish a monthly report on the ISO Website which shall show the resources designated under RCST, the megawatts of each RCST capacity designation, the duration of RCST designations, the reason for the RCST designation, and all payments, excluding costs covered in the Minimum Load Cost Report described in Section 43.11.2 herein, in dollars, itemized for system purposes as well as for each Local Reliability Area or 2007 Local Reliability Area, whichever is applicable. The ISO will provide a market notice of the availability of this report.

43.7 Payments to Resources Designated Under the RCST

43.7.1 RCST Capacity Payment

Scheduling Coordinators representing resources designated under this Section 43 will receive a RCST Capacity Payment equal to the product of the Net Qualifying Capacity, the relevant Availability Factor as determined in accordance with Appendix F, Schedule 6, and the difference between the monthly RCST charge and 95% of the Peak Energy Rent, *i.e.,* Net Qualifying Capacity x Availability Factor x (Monthly RCST Charge (Monthly Peak Energy Rent x .95)). The ISO shall determine the Availability Factor, Monthly RCST Charge and Monthly Peak Energy Rent in accordance with Appendix F, Schedule 6 of the Tariff. For purposes of this section 43.7.1, the term Net Qualifying Capacity shall mean the Megawatt value for a RCST resource as reflected in the document entitled Qualifying Capacity Megawatt Values for RA Planning Purposes (or any successor document) as posted on the ISO website, provided that, to the extent a particular resource has a stated monthly value(s), the applicable Net Qualifying Capacity shall be the average of the stated values for the months in which the resource will have an RCST designation.

For purposes of the RCST, Availability shall be calculated as the ratio of: (1) the sum of the Net Qualifying Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the ISO shall be substituted for Net Qualifying Capacity MW for each hour the resource is not on an Authorized Outage, to (2) the product of Net Qualifying Capacity MW and the total hours in the month. For purposes of this section, an Authorized Outage shall be limited to the following: (a) an ISO-approved, planned outage that exists at the time of RCST designation and is scheduled to occur during the term of an RCST designation provided that (i) such outage is not the result of a prior outage that was forced or not otherwise scheduled and approved by the ISO, and (ii) such outage may be rescheduled by the ISO during the term of the RCST designation period, provided that the term of the ISO-approved outage and the capacity derate at time of the RCST designation are not exceeded, or (b) an ISO-approved maintenance outage that is scheduled during the RCST designation period, provided such outage is not the result of a prior outage that was forced or not otherwise scheduled and approved by the ISO.

43.7.2 Minimum Load, Emissions and Start-Up Costs

43.7.2.1 Minimum Load Costs

Scheduling Coordinators representing resources designated under this Section 43 shall be eligible for recovery of Minimum Load Costs in the same manner that Scheduling Coordinators representing Resource Adequacy Resources included in Resource Adequacy Plans are eligible for the recovery of such costs under Sections 40.6B of the Tariff..

43.7.2.1.1 Allocation of Unrecovered Minimum Load Costs

Unrecovered Minimum Load Costs under Section 43.7.2.1 shall be allocated in accordance with Section 40.6B.5 of the ISO Tariff.

43.7.2.2 Emissions Costs

Scheduling Coordinators representing resources designated under this Section 43 shall be eligible for recovery of Emissions Costs in the same manner that Scheduling Coordinators representing Resource Adequacy Resources included in Resource Adequacy Plans are eligible for the recovery of such costs under Sections 40.11 of the ISO Tariff.

43.7.2.2.1 Recovery of Emissions Costs

The ISO will recover funds to pay Emissions Costs under Section 43.7.2.2 in accordance with Sections 40.11 of the ISO Tariff.

43.7.2.3 Start-Up Costs

Scheduling Coordinators representing resources designated under this Section 43 shall be eligible for recovery of Start-Up Costs in the same manner that Scheduling Coordinators representing Resource Adequacy Resources included in Resource Adequacy Plans are eligible for the recovery of such costs under Sections 40.12 of the ISO Tariff.

43.7.2.3.1 Recovery of Start-Up Costs

The ISO will recover funds to pay Start-Up Costs under Section 43.7.2.3 in accordance with Sections 40.12 of the ISO Tariff.

43.8 Allocation of RCST Capacity Payment Costs

For each month, the ISO shall allocate the costs of RCST Capacity Payments made pursuant to Section 43.7.1 as follows:

(1) Annual System RCST Designations: If the ISO makes RCST designations under Section 43.3.1, then the ISO will allocate the total costs of RCST Capacity Payments for such RCST designations (for the full term of those RCST designations) pro rata to each SC-RA Entity based on its portion of the aggregate Year-Ahead System Deficiency.

(2) Monthly System RCST Designations: If the ISO makes RCST designations under Section 43.3.2, then the ISO will allocate the total costs of RCST Capacity Payments for such

RCST designations (for the full term of those RCST designations) pro rata to each SC-RA Entity based on its portion of the aggregate Month-Ahead System Deficiency.

(3) Local RCST Designations for 2007. If the ISO makes local RCST designations for 2007 under Section 43.2.1, then the ISO will allocate the total costs of RCST Capacity Payments for such RCST designations (for the full term of those RCST designations) pro rata to each Scheduling Coordinator for an RA Entity based on the ratio of its Local Resource Adequacy Requirement Deficiency to the aggregate Local Resource Adequacy Requirement Deficiency in the 2007 Local Reliability Area. To the extent there is a Local Resource Adequacy Requirement Deficiency in two or more 2007 Local Reliability Areas that can be satisfied by designating a single unit under the RCST, the ISO shall allocate the total costs of RCST Capacity Payments for such RCST designation (for the full term of the designation) pro rata to each Scheduling Coordinator for an RA Entity that has a Local Resource Adequacy Requirement Deficiency in such 2007 Local Reliability Areas based on the ratio of its Local Resource Adequacy Requirement Deficiency to the aggregate Local Resource Adequacy Requirement Deficiency in those 2007 Local Reliability Areas.

(4) Significant Event RCST Designations for 2006: If the ISO makes any Significant Event RCST designations under Section 43.4 during 2006, the ISO will allocate the costs of such designations to all SC-RA Entities in the TAC Area(s) in which the Significant Event caused or threatened to cause a failure to meet Applicable Reliability Criteria based on Scheduling Coordinators' RA Entity Load Share Percentage(s) in such TAC Area(s).

(5) Significant Event Designations for 2007. If the ISO makes any Significant Event RCST designations under Section 43.4 during 2007, the ISO will allocate the costs of such designations to all SC-RA Entities in the TAC Area(s) in which the Significant Event caused or threatened to cause a failure to meet Applicable Reliability Criteria based on Scheduling Coordinators' 2007 RA Entity Load Share Percentage(s) in such TAC Area(s).