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March 31, 2006

The Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: ***Independent Energy Producers Association v. California Independent System Operator Corporation***
Docket No. EL05-146-000

Dear Secretary Salas:

Enclosed please find an original and fourteen copies of an Offer of Settlement of the above-captioned proceeding filed on behalf of the following Settling Parties: the Independent Energy Producers Association; the California Independent System Operator Corporation ("ISO"); the California Public Utilities Commission; Pacific Gas and Electric Company; San Diego Gas & Electric Company; and Southern California Edison Company. Consistent with Rule 602(c) of the Commission's Rules of Practice and procedure, 18 C.F.R. § 385.602(c), this filing includes the Offer of Settlement and an Explanatory Statement. The Offer of Settlement would resolve all issues in the above-referenced proceeding.

Also included with this filing, for illustrative purposes, are tariff sheets reflecting the amendments to the ISO Tariff that are necessary to implement the terms of the Offer of Settlement. Following Commission approval of the Offer of Settlement, the ISO will make a compliance to incorporate the tariff provisions into its FERC Tariff.

Copies of this filing have been served on all participants in the captioned docket as well as all Scheduling Coordinators and Participating Transmission Owners, the California Energy Commission, and the California Electricity Oversight Board. Under Rule 602(f)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602(f)(2), Comments on this Offer of Settlement are due on April 20, 2006, and Reply Comments are due on May 1, 2006. The Settling Parties request adherence to this comment period as provided in Rule 602(f)(2) in order to expedite the conclusion of this matter.

The Settling Parties request that the Commission issue an order approving the Settlement by May 24, 2006.Under the Offer of Settlement, May 24, 2006 is the date after which the ISO is permitted to designate units under the proposed Reliability Capacity Services Tariff ("RCST") for service commencing June 1, 2006. The ISO needs a week in order to make any such designations and input the necessary information into its systems to meet a June 1 effective date for RCST service. Also, under the Offer of Settlement, other agreed-to changes would have an effective date of June 1, 2006.

Two additional copies of this filing are enclosed to be date-stamped and returned to our messenger. If there are any questions concerning this filing, please contact the undersigned.

Respectfully submitted,

Michael E Ward JMM

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Attorney for the California Independent
System Operator Corporation

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Independent Energy Producers Association Complainant v. California Independent System Operator Corporation Respondent.	Docket No. EL05-146-000

EXPLANATORY STATEMENT IN SUPPORT OF OFFER OF SETTLEMENT

Pursuant to 18 C.F.R. § 385.602(c)(1)(ii), the Independent Energy Producers Association ("IEP"), the California Independent System Operator Corporation ("CAISO"), the California Public Utilities Commission ("CPUC"), Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), and Southern California Edison Company ("SCE") (collectively, "Settling Parties") hereby submit this Explanatory Statement in support of the Offer of Settlement submitted herewith.[1] This Settlement is intended to resolve all issues raised in the above-captioned proceeding.

[1] This Explanatory Statement is not intended to alter any of the terms of the Offer of Settlement. In the event of any conflict between this Explanatory Statement and the terms of the Offer of Settlement, the Offer of Settlement

(continued...)

The Settling Parties request that the Federal Energy Regulatory Commission ("FERC") issue an order approving the Settlement by May 24, 2006. Under the Offer of Settlement, May 24, 2006 is the date after which the CAISO is permitted to designate units under the proposed Reliability Capacity Services Tariff ("RCST") for service commencing June 1, 2006. The CAISO needs a week prior to the effective date of RCST service in order to make any such designations and input the necessary information into its systems. In addition, under the Offer of Settlement, the other agreed-to changes would have an effective date of June 1, 2006.

I. BACKGROUND

On June 19, 2001, in response to the California electricity crisis, the Commission adopted a series of mitigation measures, including the Must-Offer Obligation ("MOO").[2] On May 11, 2004, the CAISO filed, in Docket No. ER04-835, its Tariff Amendment No. 60 to implement modifications to the existing Must-Offer Obligation provisions of its Tariff. In its intervention and protest to Amendment No. 60, IEP requested that the Commission eliminate the MOO.[3] In its July 8, 2004, order in that proceeding, the Commission addressed the issue of the continued application of the MOO.[4] The Commission approved continuation of the MOO, but opined that the MOO should not be permanent.[5] In addition, the Commission reasoned that if IEP, or any other market participant, believed that the MOO requirement is unjust or unreasonable, it could

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shall govern. Unless otherwise stated, capitalized terms shall have the meanings provided, or incorporated by reference, in the Offer of Settlement.

2 *San Diego Gas & Elec. v. Sellers*, 95 FERC ¶ 61,418 (2001).

3 *Cal. Indep. Sys. Operator Corp.*, Motion to Intervene and Protest of the Independent Energy Producers Association, Docket No. ER04-835 (June 1, 2004).

4 *See Cal. Indep. Sys. Operator Corp.*, 108 FERC ¶ 61,022 (July 8, 2004) ("July 8 Order").

5 *See* July 8 Order at P 115.

initiate a proceeding under Section 206 of the Federal Power Act ("FPA") to challenge the existing method and to propose an alternative.[6]

On August 26, 2005, IEP filed a complaint at FERC in the above-captioned docket to replace the existing MOO with a tariff-based procurement mechanism entitled the "Reliability Capacity Services Tariff" ("RCST"). The following parties intervened on or before October 3, 2005: Alliance for Retail Energy Markets; the Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California; the California Department of Water Resources; the California Municipal Utilities Association; Calpine Corporation; Silicon Valley Power; the City and County of San Francisco, California; Constellation Energy Commodities Group; Constellation NewEnergy; Inc.; the CPUC (which is a Settling Party); the California Electricity Oversight Board; the Electric Power Supply Association; the Metropolitan Water District of Southern California; Mirant Corporation; Modesto Irrigation District; Northern California Power Agency; PG&E (which is a Settling Party); Powerex Corp.; the Sacramento Municipal Utility District; SDG&E (which is a Settling Party); Silicon Valley Leadership Group; SCE (which is a Settling Party); West Coast Power; and Williams Corp.

On October 25, 2005, the Commission issued a Notice of Technical Conference. On November 18-19, 2005, parties to this proceeding attended the technical conference at FERC and conducted initial settlement discussions.

Subsequent to the November 2005 Technical Conference, the Settling Parties conducted settlement discussions that resulted in this document.

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6 *See* July 8 Order at PP 115-116.

II. SUMMARY OF SETTLEMENT TERMS

The Offer of Settlement proposes the institution of a Reliability Capacity Services Tariff and modifications to the existing MOO requirement as a means of: (1) complementing the CPUC's Resource Adequacy Requirements ("RAR") program by providing a transition mechanism to the CPUC's full implementation of RAR; (2) providing the CAISO with a reliability backstop mechanism to acquire capacity needed to ensure the reliable real-time operation of the CAISO-controlled grid; and (3) ensuring that generators are compensated for the needed reliability and capacity that they provide. The Settlement proposes the institution of the RCST and modifications to the existing MOO as a means to achieve these important goals.

A. Compatibility With CPUC RAR Process

In CPUC Docket No. R.04-04-003, the CPUC established RAR for Load Serving Entities ("LSEs") subject to its jurisdiction ("CPUC-LSEs"). The CPUC is requiring CPUC-LSEs to acquire capacity needed to serve 115-117% of their forecast retail customer load beginning in June 2006. The CPUC emphasized that it took these steps for the following reasons:

> [T]o promote investment in the resources needed to reliably serve California's growing demand for electricity and ensure that those resources are available to the [CAISO], all while effectively and fairly allocating procurement and reliability responsibilities among market participants and oversight agencies. We are adopting RAR in order to spur infrastructure development and assure that capacity is available to the CAISO for dispatch.[7]

In addition, Local Regulatory Authorities ("LRAs") in California will establish capacity requirements for LSEs subject to their jurisdiction ("LRA-LSEs").

Even accounting for the CPUC's RAR program, the CAISO, CPUC, and others have recognized that the CAISO needs some form of additional reliability backstop to address CPUC-

7 CPUC Order D.05-10-042 at 2.

LSEs' and LRA-LSEs' deficiencies in meeting RAR, address potential market power and maintain reliable transmission grid operations. In this regard, the goal of the Offer of Settlement is to have the RCST complement the CPUC and LRA RAR programs and not interfere with, or otherwise confound, those processes. In accordance with this goal, the Settlement necessarily reflects the differences in RAR for 2006 and 2007.

1. 2006 Local RAR

For 2006, the CPUC was unable to require CPUC-LSEs to procure RAR Resources for the purpose of meeting the specific reliability needs of Local Reliability Areas because of an inadequate record. However, the CAISO has identified local reliability needs that it has to meet for contingencies that may arise in Local Reliability Areas in 2006. As part of the Offer of Settlement, the Parties have acknowledged that the CAISO may need resources to meet local reliability above those resources procured through the CPUC's 2006 RAR. As discussed in more detail below, the Offer of Settlement establishes a process by which the CAISO has identified its 2006 Local Area Reliability Needs ("LARN") and will provide entities that serve load with an opportunity to procure resources to satisfy those needs before the CAISO uses the RCST reliability backstop mechanism that will be provided through the Offer of Settlement.

2. 2007 Local RAR

The CPUC has an ongoing proceeding in which it intends to establish Local RAR for CPUC-LSEs that would specifically provide for local reliability beginning in 2007. The CPUC anticipates completing that proceeding by June 2006. The CPUC intends to require that CPUC-LSEs annually demonstrate the availability of sufficient local resources to meet the cost-benefit balance that the CPUC will determine through the Local RAR proceeding.[8] At the time of this

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[8] CPUC Order D.05-10-042 at 107 (Oct. 27, 2005).

Settlement, the Settling Parties are not aware of the extent to which LRAs have established Local RAR for LRA-LSEs.

3. System RAR

For both 2006 and 2007, LSEs will have the first opportunity to procure to meet system-wide RAR. Pursuant to the CPUC Order D.05-10-042 (as modified), CPUC-LSEs were required to demonstrate on February 16, 2005 for Summer 2006, and will be required to demonstrate on September 1, 2006 for Summer 2007 (or as that date may be modified by the CPUC), that they have procured 90% of their total summer system resource needs ("Year-Ahead System RAR Demonstration").[9] The CPUC also required CPUC-LSEs to demonstrate beginning April 30, 2006, for June 2006 and monthly thereafter, that they have procured 100% of their total monthly resource needs on a month-ahead basis for each month ("Month-Ahead System RAR Demonstration"). The Settling Parties anticipate that LRA-LSEs will meet any corresponding requirements and make corresponding demonstrations to the CAISO in compliance with LRA requirements.

B. CAISO's Reliability Backstop

Illustrative CAISO tariff provisions reflecting the substantive provisions of the Settlement are included with this filing as Attachment A to the Offer of Settlement (termed "Illustrative Tariff Sheets"). Upon Commission approval of the Settlement, the CAISO will make a compliance filing to incorporate into the CAISO Tariff the provisions included in Attachment A. The RCST will permit the CAISO to designate generation capacity to ensure grid reliability on a CAISO system-wide ("System") or Local Reliability Area ("Local") basis.

[9] For LRA-LSEs, the System RA requirement may differ, including the amount that must be demonstrated and the time period in which the demonstration must occur.

Generation capacity designated under the RCST will be required to provide capacity to the CAISO under the same MOO required of RAR capacity for a set term, depending upon whether the capacity is designated to fill a System or Local need.

1. RCST

a. Responsibility for Local Reliability

The Settling Parties recognize that each entity serving load in the CAISO Control Area shares responsibility for, and receives benefit from, the reliability of the CAISO-controlled grid. The existing transmission system in California was built to allow vertically integrated utilities to serve load in the most efficient manner, and it was built in a regulatory structure in which least cost requirements governed whether transmission or generation investments were made. The existing grid was not designed to discriminate among load on the basis of its location. Under these circumstances, the Settling Parties do not believe that it would be just and reasonable to require only local areas to bear additional costs resulting from historical practices and decisions that were never intended to have such results. Under the RCST tariff provisions, each entity serving load (hereinafter referred to as an "RA Entity," in recognition of the entities identified in Section 40.1 of the proposed Interim Reliability Requirements Programs amendment to the CAISO Tariff filed in Docket No. ER06-723) within any of the three CAISO Transmission Access Charge Areas ("TAC Areas") (which follow historical grid development) will bear a share of cost responsibility for any procurement under RCST needed to attain local reliability in the given TAC Area; that cost responsibility shall be in proportion to the RA Entity's share of peak load in that TAC Area.

b. 2006 Local RCST Designation

The CAISO issued a report on September 23, 2005, entitled "Local Capacity Technical

Analysis; Overview of Study Report and Final Results" and subsequently issued an addendum to that report dated January 31, 2006 (collectively, the "2006 LCR Report"). The 2006 LCR Report identified, as of that date, the local reliability needs for each Local Reliability Area within the CAISO Control Area.

As part of this Settlement, the CAISO has agreed to modify the 2006 LCR Report to include suitable non-generation solutions provided by Participating Transmission Owners ("PTOs") to address the contingencies of concern raised in the 2006 LCR Report.[10] Such solutions may include, but are not limited to, equipment upgrades, operating procedures (such as switching, manual load shedding or automatic load shedding), or other operations strategies or tools. Certain PTOs proposed such solutions to the CAISO.[11]

As part of the Offer of Settlement, the CAISO agreed to revise the results of the 2006 LCR Study to reflect the effect of those non-generation solutions that are both suitable to address the contingencies identified and which are in accord with Applicable Reliability Criteria ("ARC"), as well as to take into account the Reliability Must-Run ("RMR") resources that are available to the CAISO. The CAISO published the revised results in a report - the 2006 Local Area Reliability Needs Report ("2006 LARN Report") - on March 27, 2006. The report included a list of generation resources located within each Local Reliability Area that are at least minimally effective to address one or more of the contingencies used in the 2006 LCR Report

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10 The CAISO will make available to PTOs, the CPUC, and to the extent permissible under law and pursuant to the CAISO Tariff and policies, relevant LRAs, and market participants, sufficient information regarding the contingencies used in the 2006 LCR Report to allow the PTOs to propose transmission solutions appropriate to the Contingencies of Concern and implementable for 2006.

11 As part of the Offer of Settlement, the CAISO agreed to meet and confer with the PTOs with the participation, to the extent practicable, of the CPUC and relevant LRAs, to discuss the transmission solutions that the PTOs proposed.

("Contingencies of Concern") (such resources are referred to as "Local Area Resources")[12] and identified the effectiveness of each Local Area Resource relative to the .Contingencies of Concern.

In order to ensure consistency with the CPUC's RAR process and goals and those of other LRA-LSEs, the Offer of Settlement will provide RA Entities with the first opportunity to procure additional resources to meet the CAISO's LARN in an effort to minimize the CAISO's backstop reliability role. To this end, the CAISO will provide each Scheduling Coordinator that represents an RA Entity (referred to as an "SC-RA Entity") with a report that contains the allocation of responsibility for each of that SC's RA-Entities in their respective TAC Area(s), based upon such RA Entities' percentage of load in the respective TAC Area, expressed in terms of megawatts (the "Initial LARN Allocation"). The report will include the SC-RA Entity's share of credit for RMR Units, as provided in the Offer of Settlement. RA Entities will then have the opportunity to provide the CAISO with Local Area Resources needed to meet the LARN identified in the 2006 LARN Report ("LARN Demonstration").[13]

The CAISO will then evaluate the LARN Demonstrations, and determine the effectiveness of the Local Area Resources that the SC-RA Entity has committed to make available to satisfy the CAISO's LARN. The CAISO will provide a report to each SC-RA Entity that made a LARN Demonstration indicating the amount of credit against Local RSCT designation costs (the "LARN Credit") that the SC-RA Entity will receive for the Local Area

[12] LARN Demonstrations can include Distributed Generation and Participating Load resources that are dispatchable and located within the given Local Reliability Area.

[13] Nothing in the Settlement is intended to prevent an entity that acts as a Scheduling Coordinator for another entity as the result of an Existing Contract, as that term is defined in the CAISO Tariff, from seeking compensation from that entity for any charges that the CAISO may issue to the Scheduling Coordinator with regard to that entity.

Resources included in its LARN Demonstration.[14] SC-RA Entities will then have additional time to demonstrate that they have procured additional Local Area Resources to meet any remaining LARN.

After SC-RA Entities have had the opportunity to procure to meet any remaining LARN, the CAISO will conduct a further evaluation of the effectiveness of all of the resources made available to the CAISO (including those provided by SC-RA Entities through LARN Demonstrations, as well as RMR Units and Resource Adequacy Resources, wherever located) towards relieving the Contingencies of Concern. The CAISO then will publish a report that explains its evaluation of the LARN Demonstrations and other resources, and, if applicable, of the reasons (including effectiveness) that any LARNs identified in the LARN Report had not been satisfied ("Residual LARN").[15]

If any Residual LARN exist at this point in time, the CAISO may use the RCST to designate eligible generating capacity ("Eligible Capacity"),[16] other than System Resources,[17] to meet that Residual LARN. The CAISO will select the resources that will receive Local RCST Designations to achieve the greatest effectiveness in meeting contingencies of concern at the

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14 Local Area Resources in one TAC Area offered through LARN Demonstrations can only be used to establish LARN MW Credit within that TAC Area, to provide a reasonable nexus between the portion of the grid used by the RA Entity and the resources procured by that LSE, and to reasonably ensure that procurement is targeted to meet LARN and not over-procured or under-procured in any TAC Area.

15 The CAISO will convene a teleconference to discuss the report (the "Residual LARN Report") no later than April 26, 2006.

16 RCST cannot be used, regardless of whether the RCST is intended to serve local or system needs, to designate the following: capacity associated with hydroelectric generation, nuclear generation, QFs, generation resources within a Metered Subsystem, resources owned by the California Department of Water Resources, State Water Project; capacity of a Generating Unit with a Reliability Must-Run contract, during the term of such contract; capacity of a Resource Adequacy Resource that is identified in any Resource Adequacy Plan in accordance with Section 40, during the time that such capacity is identified on the Resource Adequacy Plan; and capacity that has been designated to provide serve under the RCST, during the term of the designation.

17 Although System Resources may be used for System RCST Designations, System Resources cannot be used to satisfy local reliability needs and are, therefore, ineligible for Local RCST Designations.

lowest overall cost. The CAISO will have latitude to procure slightly more or slightly less than the Residual LARN amount, due to the granularity in size of available resources. Local RCST Designations for 2006 will be for the balance of the year.

c. 2007 Local RCST Designation

Local RCST Designations for 2007 may only occur if there is an aggregate deficiency by CPUC-LSEs and LRA-LSEs in meeting the Local RAR established by the CPUC and LRAs for 2007 (accounting for RMR) for any local area. In addition, the State Water Resources Development Project, commonly known as the State Water Project of the California Department of Water Resources, shall be required to develop, in conjunction with the CAISO, a program that ensures that it will not unduly rely on the local resource procurement practices of CPUC-LSEs and LRA-LSEs. The CAISO will make Local RCST Designations in 2007 on the same factors as used for 2006. The CAISO will make Local RCST Designations for 2007 only after it designates RMR Units in the 2007 Local Area Reliability Study ("LARS") process. Local RCST Designations for 2007 will be for the full year.

d. System RCST Designation

After the CAISO has evaluated the Year-Ahead System RAR Demonstrations, the CAISO will calculate the total megawatt deficiency. If there remains a net shortfall for Year-Ahead System RAR Demonstrations after the CAISO makes Local RCST Designations, then the CAISO may make System RCST Designations.

Year-Ahead System RCST Designations shall be limited to the net capacity shortfall below the CPUC and LRA showing requirements (the "Year-Ahead System Resource Deficiency"). The CAISO will have latitude to procure slightly more or slightly less than the Year-Ahead System Resource Deficiency, due to the granularity in size of available resources.

Year-Ahead System RCST Designations will have a minimum term of three months and a maximum term of four months for 2006 (June through September) and five months for 2007 (May through September).

Month-Ahead System RCST Designations shall be limited to the net capacity shortfall below the CPUC and LRA showing requirements ("Month-Ahead System Resource Deficiency"), with reasonable allowance for granularity. Month-Ahead System RCST Designations will be limited to terms of the lesser of three months or the balance of the calendar year.

The CAISO may issue System RCST Designations to resources internal to the CAISO control area or to System Resources, but System Resources will be subject to the CAISO's established import limits for RAR purposes. The CAISO will make System RCST Designations by assessing the costs and benefits of such a designation to total grid reliability based upon the unit's effectiveness at resolving local and zonal constraints and the overall cost of the designation, including the number of megawatts procured and Minimum Load Costs and Start Up Costs.

e. RCST Selection

The CAISO may designate Eligible Capacity under the RCST, in accordance with the criteria provided in the Offer of Settlement, up to the qualifying capacity of the applicable generating unit. The CAISO will be open and transparent to the maximum extent permissible under law about the factors and processes used when making RCST designations.

f. RCST 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 notice to withdraw from the

Participating Generator Agreement ("PGA"), then the Participating Generator shall be obligated pursuant to the RCST provisions of the CAISO Tariff for the term of the RCST designation. If a Participating Generator's Eligible Capacity is designated under the terms of the RCST subsequent to when the Participating Generator filed notice to withdraw from the PGA, then the Participating Generator will provide RCST Service until the date that its PGA effectively terminates, but it will not be under an obligation pursuant to the RCST provisions of the CAISO Tariff after the date that its PGA effectively terminates. If a Participating Generator's RCST Eligible Generating Capacity is designated under the terms of the RCST any time after the Participating Generator has filed notice to withdraw from the PGA, and the Participating Generator agrees to provide service under the RCST provisions of the CAISO Tariff, then the Participating Generator will enter into a PGA for the designated generating unit and invoice the CAISO for any actual applicable restoration costs.

g. RCST Replacement Option

Under the terms of the settlement, providers of RCST Service may substitute Eligible Capacity in the event the RCST resource is unavailable. Such a substitute must be a resource in the same location as the RCST resource, either at the same bus, or in the same local area. However, in the event that the substitute resource is not at the same bus, then the substitution is subject to the CAISO's approval, which the CAISO cannot unreasonably withhold if the proposed substitute resource meets the CAISO's effectiveness and operational needs.

If the RCST Service Provider substitutes an RCST unit and the CAISO has approved the substitute, if such approval is required, then: (1) the RCST Service Provider must pay all bilateral substitution costs, as well as all additional Minimum Load Costs, Start Up Costs, and Emissions Costs (above the corresponding costs of the Generating Unit that is being replaced);

and (2) the actual availability of the substitute resource during the substitute period will be used for purposes of determining monthly RCST capacity payment for the original RCST resource. If the RCST Service Provider does not elect to offer a substitute resource, the substitute resource is not approved by the CAISO (if such approval was required), or if the approved substitute resource becomes unavailable, then: (1) the RCST Service Provider is not responsible for CAISO replacement costs; and (2) the actual availability of the original RCST resource will be used for purposes of determining monthly RCST capacity payment for the original RCST resource.

h. Relationship Between RMR and RCST in 2007

As the CAISO's RMR process for 2006 already has been finalized, the Offer of Settlement necessarily accommodates the relationship between 2006 RMR capacity and RCST capacity. The CAISO will determine its RMR needs and designate units for RMR for 2007 using the same LARS process used in 2006. In this process, the CAISO will not modify either the need assessment process or the criteria by which it makes RMR designations, and it will not prefer RCST over RMR. The CAISO will publish the 2007 RMR requirements (including RMR quantities and, to the extent that the CAISO can make it available, specific resource information) no later than July 1, 2006.

The CAISO will procure Ancillary Services from RMR resources that switch from the Condition 1 to Condition 2 under the RMR Contract after March 31, 2006 to satisfy Ancillary Services requirements in the same manner that the CAISO has historically used Condition 2 units for Ancillary Services. Specifically, the cost-based bids of such Condition 2 units will be placed in the Ancillary Services bid stack, and the CAISO will accept bids in the stack in merit order until its Ancillary Services needs are satisfied. The bids of Condition 2 RMR resources that are

Condition 2 prior to March 31, 2006, will not be considered by the CAISO in the Ancillary Services bid evaluation process.

The terms of the Settlement will not affect the provisions of the RMR Contract that provide for payment for capital additions or termination that were approved by the CAISO while the resource was subject to the RMR Contract.

2. Must-Offer Obligation

Under the Settlement, and as reflected in the Illustrative Tariff Sheets, the CAISO also will retain the current MOO requirement for the same type of generation capacity that currently is subject to the existing MOO ("FERC Must Offer Generators"). Generation subject to the MOO must continue to commit their capacity in the CAISO's Real-Time market unless granted a Must-Offer Waiver Denial ("MOWD").[18] Under the Offer of Settlement, however, before issuing MOWD under the current MOO requirement, the CAISO must first exhaust the other resources that will be made available to it, including resources under contract to provide RAR, RMR, and resources designated under the RCST. In addition, the CAISO must provide an explanation as to why it has issued the MOWD.

If the CAISO cannot satisfy its operational needs, taking into account all resource operational constraints with resources subject to RAR, RMR, or RCST, then the CAISO may issue MOWD to FERC Must Offer Generators. To the extent that transmission solutions have been included in the determination of Local Reliability Area or 2007 Local Reliability Area

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18 Nothing in the Settlement is intended to modify the authorities under which resources counted for RAR are, or will be, subject to a must-offer obligation, nor the compensation that such RAR Resources will receive. Nothing in the Settlement is intended to modify the authorities under which RMR Units currently are subject to the MOO under the current CAISO Tariff, or the compensation that RMR Units will receive. As discussed in further detail in this Explanatory Statement, capacity designated under the RCST shall be subject to a must-offer obligation to the same extent as RAR Resources. Once designated, RCST capacity must offer Ancillary Services to the extent capable.

capacity requirements, the CAISO shall incorporate the day-to-day operational value of these alternatives into its report on why the MOWD was issued.

For 2006, the parties anticipate that the CAISO will not need to issue any MOWDs to FERC Must Offer Generators to meet local area reliability needs or system-wide needs unless, with respect to local area reliability needs, a material difference in grid operations occurs relative to what was assumed in developing 2006 LARN Report (a "Significant Event"), or unless RAR capacity is not made available to the CAISO.

3. RCST Trigger For MOWD For Significant Events

If the CAISO issues a MOWD to Eligible Capacity (on a unit-specific basis) on four separate days in any one-year period, then the CAISO will evaluate whether a Significant Event has occurred that warrants an RCST designation (a "MOWD Evaluation"). The CAISO will conduct a MOWD Evaluation after every four separate days on which the CAISO issues a MOWD to Eligible Capacity (on a unit-specific basis) (*i.e.*, an evaluation will occur after the 4th, 8th, 12th, 16th, and so on, day on which a MOWD is issued to a specific unit). The CAISO may designate a resource under the RCST following a Significant Event if such RCST designation is necessary to remedy any resulting material differences in CAISO Controlled Grid operations relative to the assumptions underlying the development of 2006 or 2007 local resource adequacy requirements. The CAISO shall take into account the expected duration of the Significant Event in determining whether to make such a RCST designation.

C. Generation Compensation for Needed Reliability and Capacity

If approved, the Offer of Settlement will compensate generation for the reliability and capacity that they provide to the market. Compensation for generation capacity that is either designated under the RCST or subject to a MOWD is based on a Reference Resource that is intended to reflect new entry into the market. That Reference Resource has a target capacity price of \$73/kW-Yr and a target availability rate of 95%. The Reference Resource has an assumed heat rate of 10,500 BTU/kWh, and its variable operations and maintenance costs are based on the Energy Information Administration's AEO Electricity Market Module Assumptions, which are currently \$3.16/MWh. Finally, daily gas prices and emissions allowance costs will be derived from the trade press used by the CAISO in the normal course of its business, which will be used to estimate variable costs. The agreed-upon compensation represents a negotiated settlement, without reliance on a specific methodology for deriving the Reference Resource assumptions or basis for adjustments from the Reference Resource.

1. RCST Capacity Compensation

Generation capacity that is designated under the RCST will be paid a Monthly RCST Payment based on the following formula:

Monthly RCST Payment = (Monthly RCST Charge-(Monthly PER **x** .95)) **x** Net Qualifying Capacity **x** Availability Factor

Each of these factors is described more fully below:

a. Monthly RCST Charge

The Monthly RCST Charge is calculated by multiplying the proxy unit annual capacity price of \$73/kW-yr by certain Monthly Shaping Factors, which are intended to weight the value of capacity in accordance with demand. For example, the Monthly Shaping Factor for SP-15 is 5% in February and 17.5% in August. All of the Monthly Shaping factors for SP-15 and NP-15 / ZP-26 are set forth in the Offer of Settlement.

b. Calculation of the Monthly PER

The Offer of Settlement contains a mechanism to ensure that RCST compensation fairly reflects the proxy operations of the Reference Resource. The Monthly RCST Payment will be reduced by the amount of Monthly Peak Energy Rent ("Monthly PER") that the Reference Resource would have received, assuming that the Reference Resource would have been dispatched when such dispatch was economically rational and would otherwise provide Ancillary Services.

The CAISO will calculate the Monthly Peak Energy Rent ("Monthly PER") as follows: immediately following the end of the month the CAISO will determine the hours during which the Reference Resource would have been dispatched (based on the Reference Resource's characteristics) to provide either energy or non-spinning reserves and will calculate, on a per kW-Month basis, the total dollar amount of rent (defined as earnings in excess of the Reference Resource's variable costs calculated using Reference Resource unit characteristics) that would have been earned by the Reference Resource.

The Reference Resource will be assumed to have been dispatched for energy in any hour in which the hourly energy price described below is greater than the Reference Resource variable cost. The CAISO shall use its day ahead non-spinning reserve price to calculate the rent for all hours in which the Reference Resource is not assumed to have been dispatched to provide energy (*i.e.,* any hour where the hourly price is less than the Reference Resource variable costs). The CAISO will use hourly energy prices that are the weighted average of: (1) the applicable zonal on/off peak day-ahead index prices set forth in Platts Megawatt Daily, shaped to hourly profiles using the factors specified in the Offer of Settlement, and (2) the applicable zonal CAISO hourly average real-time energy prices.

c. Net Qualifying Capacity

For purposes of calculating the Monthly RCST Payment, Net Qualifying Capacity is defined in the Settlement as the Megawatt value for a RCST resource as reflected in the document entitled Qualifying Capacity MW Values for RA Planning Purposes (or any successor document) as posted on the CAISO website, provided that, to the extent a particular resource has multiple monthly values, 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.

d. Availability

As noted above, the Reference Resource has a target "Availability" factor of 95%. In order to provide the proper incentives and penalties to ensure that RCST capacity is available when needed, the Offer of Settlement provides for bonus payments for RCST capacity Availability above 95%, and economic penalties for RCST capacity Availability that falls below 95%. The CAISO will calculate availability on a monthly basis using actual availability data based upon Real-Time operations data. These incentives and penalties are set forth in the "Availability Factor Table" in the Offer of Settlement.

2. Uplift for Start-Up and Minimum Load Costs

If generation capacity that is designated under the RCST has not been self-scheduled in the Day-Ahead or Hour-Ahead Markets and receives an RCST MOWD from the CAISO, the CAISO shall pay such providers of RCST Service a Start-Up and Minimum Load Cost Compensation ("MLCC") uplift in addition to RCST capacity payments. Any unrecovered MLCC shall be paid as an uplift to the extent that the ten (10) minute Settlement Interval Ex Post Price is insufficient for the resource to recover its Minimum Load Costs.

3. MOO Compensation

Other than the capacity payment discussed below, the Offer of Settlement does not otherwise alter the current payment structure set forth in the CAISO Tariff for FERC Must Offer Generators. Specifically, such a resource will receive a cost-based Start-Up and MLCC, as well as an imbalance energy payment for minimum load energy provided pursuant to a MOWD instruction. Nothing in the Settlement is intended to otherwise modify the other aspects of the existing MOO (*e.g.*, minimum load tolerance limits to qualify for MLCC).

Providers of capacity from units that are not designated under RCST, nor subject to RAR nor RMR contracts, shall also receive a daily capacity payment equal to 1/17th of the Monthly RCST target capacity price for each day that the Unit receives a MOWD ("Must-Offer Capacity Payment").[19] However, once a unit receives certain compensation in a calendar month as contemplated in the Offer of Settlement[20] equal to the Maximum Monthly RCST Payment as reduced by the Monthly PER, multiplied by the megawatts of Eligible Capacity, it will not receive any further Must Offer Capacity Payments for the month (nor will it receive any further Frequently Mitigated Bid Adders, as discussed below).[21]

4. Frequently Mitigated Unit Compensation

Under the current CAISO Tariff, a generation resource that self-schedules and has its Supplemental Incremental bids mitigated is paid a mitigated price. Under the Offer of Settlement, the following Generating Units that are Frequently Mitigated shall receive an incremental payment as set forth in this section: Generating Units of Participating Generators for which the CAISO 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

[19] Eligible Capacity that does not constitute the total Qualifying Capacity of a specific generating resource ("Partial Units") is not eligible to receive the 1/17th payment. The Monthly Total MOWD Payments shall be reduced on an hourly *pro rata* basis for any period of time in the calendar day that the unit experiences a forced outage. Additionally, the payment shall be reduced in a manner consistent with existing MOO payment reductions for startup and MLCC payments for failure to meet obligations or operating requirements of a MOWD (*e.g.*, hourly pro rata reductions for the hour(s) in question).

[20] The relevant compensation is a combination of: (i) total Must-Offer Capacity Payments that a FERC Must Offer Generator has received for a Generating Unit under this Section during that month, (ii) the total Imbalance Energy payments received when that Generating Unit is running at minimum load, and (iii) any Frequently Mitigated Adders accrued during the calendar month. Imbalance Energy payments and start-up costs will continue to accrue even if the unit has received the equivalent of the Maximum Monthly RCST Payment as reduced by the Monthly PER from these sources.

[21] Payments for supplemental energy beyond that produced when operating at minimum load levels are separate from these payments and do not affect these payments.

Generators that have Eligible Capacity. "Frequently Mitigated" means that Eligible Capacity described above has had its Supplemental Incremental bids mitigated for local-area constraints more than four (4) times in a Trading Day. Bid mitigation will be determined on a five-minute dispatch period.[22] This payment recognizes that a unit whose bid is taken out of merit order and mitigated under the CAISO's local market power mitigation measures might be needed for reliability and it is therefore appropriate for that unit to receive a payment in lieu of the capacity payments made for RCST and MOWD.

Beginning with the ten-minute settlement interval containing the fifth such bid mitigation ("Mitigated Interval"), and continuing for each Mitigated Interval thereafter in that same Trading Day , the rate of payment for the mitigated MW amount will be increased to the greater of Mitigated Interval MCP or reference price, plus $40/MWh ("Frequently Mitigated Adder"). For units with Eligible Capacity that does not constitute the total Qualifying Capacity of a specific generating resource ("Partial Units") that are self-scheduled under the CAISO Tariff or that receive a MOWD pursuant to proposed Section 40.7.6 of the CAISO Tariff, the Frequently Mitigated Adder will be multiplied by the ratio of the Generating Unit's Capacity not under an RA Resource contract (excluding minimum operating level) to the total Qualifying Capacity of the resource.

The total amount of Frequently Mitigated Adders for any unit shall not exceed the daily Must-Offer Capacity Payment in any Trading Day. Further, as noted above, Frequently Mitigated Adders will stop accruing in a calendar month once the combined total of Must-Offer Capacity Payments, Minimum Load imbalance energy payments and monthly total Frequently Mitigated Adder compensation reaches the level of the Maximum Monthly RCST Payment as

22 Frequently Mitigated Adders do not apply to "Decremental" instructions received for local area constraints.

reduced by the Monthly PER, multiplied by the megawatts of Eligible Capacity for the resource.

D. Cost Allocation

The Offer of Settlement includes provisions for allocating the costs associated with RCST and the new payments associated with the MOO. For System RCST Designations, the cost will be allocated to the SC-RA Entity[23] for each deficient RA Entity based on the ratio of such RA Entity's deficiency relative to total RA Entity deficiencies in the CAISO Control Area. For 2006 Local RCST Designations, the costs will be apportioned to SC-RA Entities[24] in order to credit SC-RA Entities for the local resources that they self-provide to the CAISO, as evidenced through their LARN Demonstrations, according to a multi-step process specified in the settlement. Attachment B to the Offer of Settlement provides specific examples of allocation of costs for Local RCST Designations for 2006. Cost allocation for local RCST designations in 2007 is reserved pending action by the CPUC and LRAs in establishing local resource adequacy requirements.[25]

In addition, the Offer of Settlement has specific cost allocation provisions for Local RCST Designations triggered by Significant Events, the Must-Offer Capacity Payment, and the costs associated with Frequently Mitigated units.

E. Reporting

To provide transparency and promote efficiencies, as well as to inform future RAR decisions, the CAISO will publish monthly reports regarding RCST designations and the allocation of MLCC Uplift, Minimum Load Costs, and Start-Up costs under both RCST and MOWD, as well as reports concerning the use of MOWD, all as described in the Offer of

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23 *See* footnote 2 of the Offer of Settlement.

24 *See id.*

25 *See id.*

Settlement.

F. System Automatic Mitigation Procedures and Local Market Power Mitigation

The Offer of Settlement provides that the System Automatic Mitigation Procedures ("AMP") threshold will be set at $200/MWh, effective June 1, 2006. All resources shall be subject to System AMP and the conduct and impact tests currently in place will remain unchanged.

In addition, Local Market Power Mitigation, as set forth in the CAISO Tariff, shall remain unchanged, except as follows: (1) the incorporation of the Frequently Mitigated Adder discussed above; and (2) the reference price will now use daily gas index prices.

G. CPUC Proceeding R.05-12-013

Nothing in the Offer of Settlement predetermines what the CPUC may do in CPUC Docket No. R.05-12-013 or any other proceeding, or alters any CPUC jurisdictional rights, including, without limitation, the CPUC's jurisdiction regarding cost allocation and compensation schemes among CPUC-LSEs regarding RARs imposed by the CPUC.

H. Termination Provisions

The Tariff provisions implementing the terms of the Offer of Settlement will automatically expire on the earlier of December 31, 2007 or the implementation of the CAISO's Market Redesign and Technology Update ("MRTU"), except to the extent necessary to provide compensation to those units that had provided service under those provisions prior to their termination. Notwithstanding the foregoing, no party waives its Section 205 or 206 rights with respect to any provision of the CAISO Tariff.

If the Commission, in approving the Settlement, or any other regulatory action modifies the Settlement in a manner that materially changes the benefits and burdens negotiated herein, the Settling Parties shall meet and confer as to whether all Settling Parties can agree to the modified Settlement. If all of the Settling Parties do not agree, in writing, to the modified Settlement, then the Settlement shall terminate.

III. ADDITIONAL INFORMATION

A. What are the issues underlying the settlement and what are the major implications?

The factual and procedural background of this proceeding, the issues underlying this proceeding, and the major implications of this proceeding have been summarized in Sections I and II above. The Settling Parties expressly agree that this is a negotiated settlement, and its terms set no precedent regarding future rates. The Settlement resolves all issues between the Settling Parties.

B. Whether any of the issues raise policy implications?

The Offer of Settlement furthers the broad public interest favoring settlements.[26] Beyond that, the Offer of Settlement does not raise policy implications.

C. Whether other pending cases may be affected?

The Parties do not believe that the Offer of Settlement affects any other pending cases. However, the Settling Parties note that certain provisions of this settlement refer to and/or build on proposed tariff changes filed in Docket No. ER06-723, which proposed changes are currently pending before the Commission.

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[26] *See Southern Union Gas Co. v. FERC*, 840 F.2d 964, 971 (D.C. Cir. 1988).

D. Whether the settlement involves issues of first impression, or if there are any previous reversals on the issues involved?

The Offer of Settlement involves issues of first impression, and there are no previous reversals on the issues involved in this proceeding. The Parties note that with respect to the issue of the appropriate allocation of MLCC, the Offer of Settlement adopts the methodology that will ultimately be approved by the Commission in the Amendment No. 60 proceeding in Docket No. ER04-835. Likewise, the proposed methodology for allocating Must Offer Capacity costs follows the methodology ultimately approved by the Commission in the Amendment No. 60 proceeding.

E. Whether the proceeding is subject to the just and reasonable standard or whether there is *Mobile-Sierra* language making it the standard, *i.e.*, the applicable standards of review?

The Settling Parties intend the just and reasonable standard of review to apply to this Settlement.

IV. DUE DATES FOR COMMENTS

In accordance with Rule 602, initial comments on the Settlement are due April 20, 2006, and reply comments are due May 1, 2006.

V. CONCLUSION

The Offer of Settlement would fully resolve all of the issues raised in Docket No. EL05-146. Commission approval of the Offer of Settlement is vital to ensure that the CAISO has the reliability backstop mechanism that it needs during the transition into the CPUC's RAR construct, to further California's goals of resource adequacy, and to ensure that generation resources receive compensation for the needed reliability and capacity services that they provide. Moreover, Commission approval of the Settlement will save the Settling Parties and the Commission the expense and risks associated with continued litigation.

For all of the foregoing reasons, the Parties respectfully request that the Commission find that the Offer of Settlement is fair and reasonable, and in the public interest, and approve it without modification.

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Independent Energy Producers Association Complainant v. California Independent System Operator Corporation Respondent	Docket No. EL05-146-000

OFFER OF SETTLEMENT

The Independent Energy Producers Association ("IEP"), the California Independent System Operator Corporation ("CAISO"), the California Public Utilities Commission ("CPUC"), Pacific Gas & Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (together the "Settling Parties")[1] hereby offer the following terms and conditions of a settlement (the "Settlement") to each of the parties to the above-captioned proceeding. If approved by the Federal Energy Regulatory Commission, this Settlement will resolve all issues in this proceeding.

TERMS

The terms of the Settlement are as follows:

ARTICLE 1

DEFINITIONS

1.1 All defined terms shall have the meaning as set forth in the CAISO open access

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1 Parties that join this Settlement subsequent to its being filed shall also constitute "Settling Parties."

tariff as it exists on the Effective Date ("CAISO Tariff") unless otherwise defined herein or in Attachment A to this Offer of Settlement (entitled "Illustrative Tariff Sheets"), or in the proposed Interim Reliability Requirements Programs amendment to the CAISO Tariff filed in Docket No. ER06-723 ("Amendment 74"). In the event of a conflict between the meaning given to defined terms in the CAISO Tariff, Amendment 74, this Settlement, and/or the Illustrative Tariff Sheets, the meaning provided by the Illustrative Tariff Sheets shall govern.

1.2 Contingencies of Concern means contingencies evaluated by the CAISO in the study that resulted in the LCR Report that caused the CAISO to identify an area as a Local Reliability Area.

1.3 Effectiveness means the ability of a resource to address one or more Contingencies of Concern affecting a Local Reliability Area, expressed as a percentage with respect to each relevant Contingency of Concern of the ability of the most effective resource to address that contingency.

1.4 Eligible Capacity means Capacity of Generating Units of Participating Generators located within the ISO Control Area except the following: capacity associated with hydroelectric generation, nuclear generation, or Qualifying Facilities; generation resources within a Metered Subsystem; resources owned by the California Department of Water Resources, State Water Project; capacity of a Generating Unit with a Reliability Must-Run contract, during the term of such contract; capacity of a Resource Adequacy Resource that is identified in any Resource Adequacy Plan in accordance with Section 40 ("RA Resource"), during the time that such capacity is identified on the Resource Adequacy Plan; and capacity that has been designated to provide service under the RCST, during the term of the designation.

1.5 Local Area Resource is a Generating Unit located in a Local Reliability Area that has a material degree of Effectiveness.

1.6 Local Reliability Area means a geographically contiguous area within a TAC Area that the CAISO has determined, through the LCR Report, requires Local Area Resources to meet Applicable Reliability Criteria.

1.7 Local RCST Designation means the designation of Eligible Capacity to provide service under the RCST to the CAISO to meet Applicable Reliability Criteria in a Local Reliability Area.

1.8 RA Entity means any entity identified in Section 40.1 of the CAISO Tariff.

1.9 Reliability Capacity Services Tariff ("RCST") means section 43 of the CAISO Tariff concerning provision of RCST service, an illustrative version of which, together with conforming changes to other Sections of the CAISO Tariff, are provided in Attachment A (the "Illustrative Tariff Sheets").

1.10 RCST Service Provider means the owner of Eligible Capacity that has been designated by the CAISO under the RCST.

1.11 System RCST Designation means the designation of Eligible Capacity to provide RCST services to the CAISO to meet the system-wide planning and operational margins established by the CPUC and local regulatory authorities ("LRAs").

ARTICLE 2

2.1 The 2006 Local RCST Designation Process

2.2 *2006 Local Area Reliability Needs Identification Process.* On September 23, 2005, the CAISO issued a report entitled, "Local Capacity Technical Analysis, Overview of Study Report and Final Results," ("LCR Report"[2]) which, together with an addendum dated January 31, 2006, identified Local Reliability Areas within the CAISO Control Area and the local reliability needs of those areas. This LCR Report will form the basis upon which the CAISO will determine its 2006 Local Area Reliability Needs ("LARN"), as amended by the 2006 LARN Report (as defined in Section 2.2(c)).

(a) The CAISO has made available to Participating Transmission Owners ("PTOs") information regarding the operational contingencies that the CAISO used in the 2006 LCR Report, in order to allow the PTOs to propose transmission solutions (such as equipment upgrades, operating procedures such as switching, manual Load shedding or automatic Load shedding, and other operational strategies or tools (collectively, "Non-Generation Solutions")) that are appropriate to address the Contingencies of Concern and that can be implemented for 2006.

(b) The PTOs that chose to do so proposed Non-Generation Solutions to the CAISO on or about March 3, 2006.

(c) The CAISO has revised the results of the LCR Report to reflect the effect of those Non-Generation Solutions that are suitable to address the contingencies of concern, and accord with Applicable Reliability Criteria ("ARC"). The CAISO published the revised results in a report titled the 2006 Local Area Reliability Needs Report (the "2006 LARN

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2 This report has come to be known as the LCR Report; the derivation of the name comes from the CAISO's use of the term "Local Capacity Requirements" (abbreviated "LCR") in the report.

Report") on March 27, 2006. The 2006 LARN Report identifies each Local Reliability Area, provides the amount of generation (in megawatts) needed for that local area to comply with ARC, and explains all assumptions that the CAISO used in preparing the Report. The 2006 LARN Report also includes a list of each Local Area Resource and identifies the Effectiveness of each such resource (either directly or by reference).

2.2.2 *Opportunity for RA Entities to Provide Needed Resources.*

(a) The CAISO will use the RA Entity's 2005 actual annual coincident peak Load in each Transmission Access Charge Area ("TAC Area") to determine each RA Entity's percentage of annual coincident Load in the TAC area. The CAISO will then apply the resulting percentage to the LARN identified in the 2006 LARN Report for the respective TAC Area, to determine the proportionate share of responsibility for the LARN in that TAC Area for each Scheduling Coordinator for an RA Entity ("SC-RA Entity").

(b) The CAISO will provide each SC-RA Entity with a report on or about March 31, 2006, containing each SC-RA Entity's share of the LARN in each of the TAC Area(s) in which its RA Entities serve load, expressed in terms of megawatts (the "Initial LARN Allocation"),[3] with a copy of each report to a CPUC-jurisdictional entity sent to the CPUC. The Initial LARN Allocation will reflect reductions for Non-Generation Solutions and, for each RA Entity that contributes to Annual Fixed Revenue Requirement or Annual Fixed Reliability Costs (or, through a RA Resource contract, their functional equivalent), a credit for Reliability Must-Run ("RMR").

[3] Nothing in the Settlement is intended to prevent an entity that acts as a Scheduling Coordinator for an RA Entity as the result of an Existing Contract, as that term is defined in the CAISO Tariff, from seeking compensation from that RA Entity for any charges that the CAISO may issue to the entity with regard to that RA Entity.

(c) Each SC-RA Entity may make a demonstration to the CAISO by April 7, 2006, of the Local Area Resources that its RA Entities will make available to the CAISO for 2006 (the "LARN Demonstration"), which may include resources that were part of the RA Entities' Annual System Resource Adequacy Requirements demonstration. The CAISO will count toward the LARN Demonstration all physical System Resource Adequacy Requirements resources that are Local Area Resources in the TAC Area in which the SCE-RA Entity's RA Entities serve load.

(d) The CAISO will evaluate the LARN Demonstrations, and determine the Effectiveness of the Local Area Resources that each SC-RA Entity has committed to make available to the CAISO. In evaluating the effectiveness of LARN Demonstrations to meet the LARN, the CAISO will take into account the Effectiveness of RMR resources and Resource Adequacy Resources in addition to resources identified in the LARN Demonstrations, whether or not they are located in the Local Reliability Area.

(e) By April 17, 2006, the CAISO will provide each SC-RA Entity that makes a LARN Demonstration with a report, with a copy of each report for a CPUC-jurisdictional entity to be sent to the CPUC, indicating the amount of credit (the "LARN Credit") that the SC-RA Entity will receive for the Local Area Resources that its RA Entities will make available to the CAISO in each TAC Area in which its RA Entities serve Load. The Local Reliability Area Resources in one TAC Area offered through LARN Demonstrations cannot be used to establish LARN Credit for another TAC Area. The report will explain the CAISO's evaluation of the LARN Demonstrations and the reasons (including Effectiveness) that the SC-RA Entity's proportionate share of any LARNs were not satisfied by the combination of: (i) the SC-RA Entity's LARN Demonstration; (ii) its proportionate share of RMR Resources (if any, and regardless of whether such resources are located inside or outside of a Local Reliability Area); (iii) its proportion of the aggregate effect of Resource Adequacy Resources that are not Local Areas Resources (provided the SC-RA Entity agrees to keep such information confidential); and (iv) its proportion of the aggregate effect of any other resources made available to the CAISO, regardless of whether such resources are located inside or outside of a Local Reliability Area. No later than April 26, 2006, the CAISO will convene a teleconference with SC-RA Entities to discuss its evaluation of the LARN Demonstrations.

(f) By May 5, 2006, SC-RA Entities may make a demonstration to the CAISO of any additional Local Area Resources that they have procured since the SC-RA Entity's LARN Demonstration to meet any unsatisfied LARNs. The CAISO will evaluate the demonstrations of additional Local Area Resources made by May 5, 2006, as well as the April 30th Monthly System Resource Adequacy Requirements demonstrations that the RA Entities subject to CPUC jurisdiction ("CPUC-RA Entities") must make before the CPUC, and determine the Effectiveness of those resources in meeting unsatisfied LARNs.

2.2.3 *Local RCST Designation to Meet Residual LARNs in 2006*

(a) Residual LARN Report. No sooner than May 17, 2006, the CAISO will issue the Residual LARN Report, which will account for any additional resources demonstrated by SC-RA Entities by May 5, 2006, that can reduce the initially unsatisfied LARN, and identify any remaining unsatisfied LARN ("Residual LARN"). The Residual LARN Report will include: (1) the CAISO's evaluation of the LARN Demonstrations of all RA Entities, including a determination of the Effectiveness of all resources in the LARN Demonstrations; (2) if relevant, the reasons that the aggregate LARN Demonstrations of all RA Entities, combined with RMR Units and Resource Adequacy Resources (wherever such RMR Units and Resource Adequacy Resources may be located), have not satisfied the LARN in any Local Reliability Area, and (3) the amount of any Residual LARN in any Local Reliability Area.

(b) Timing of Local RCST Designation for 2006. No sooner than May 24, 2006, and only after receiving all appropriate Commission authorizations, the CAISO may designate eligible generating capacity ("Eligible Capacity") to meet any Residual LARN ("Local RCST Designations").

(c) Term of Local RCST Designations for 2006. Local RCST Designations for 2006 will have a term that commences no sooner than June 1, 2006, and terminates at midnight on December 31, 2006.

2.2.4 *Local RCST Designations in 2007.*

(a) The CAISO shall make Local RCST Designations for 2007 only if there is an aggregate deficiency by RA Entities in meeting the Local Resource Adequacy Requirements established by the CPUC and Local Regulatory Authorities ("LRAs") for 2007 (accounting for RMR affecting any 2007 Local Reliability Area, as well as the Effectiveness of any Resource Adequacy Resources, regardless of the location of those resources). 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 CAISO, a program that ensures that it will not unduly rely on the local resource procurement practices of other entities that serve load.

(b) The CAISO shall make Local RCST Designations for 2007 only after the RMR units have been designated in the 2007 Local Area Reliability Study ("LARS") process for 2007.

(c) Local RCST Designations for 2007 will have a term commencing January 1, 2007, and terminating on the earlier of midnight on December 31, 2007 or midnight on the day preceding the effective date of the MRTU Tariff.

2.2.5 *Selection of Local RCST Designations.*

The CAISO shall make Local RCST Designations based on the lowest overall cost for each TAC Area or 2007 Local Reliability Area, whichever is applicable, considering the following factors: the effectiveness of the Eligible Capacity in addressing binding contingencies within a Local Reliability Area or a 2007 Local Reliability Area, whichever is applicable; the quantity of Eligible Capacity of the resource relative to the remaining need for such resources; and the Start-Up and Minimum Load Costs associated with the Eligible Capacity. The CAISO 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 that is available and suitable to meet the deficiency, consistent with the criteria set forth in this section.

ARTICLE 3

RCST DESIGNATIONS FOR "SYSTEM" REASONS

3.1 *System Resource Adequacy Requirements Procurement.* On February 16, 2006, pursuant to the CPUC Order D.05-10-042 (as modified), CPUC-RA Entities were required to demonstrate, for Summer 2006, that they have procured ninety percent (90%) of their total summer system resource needs ("Year-Ahead System RAR Demonstration").[4] Pursuant to the CPUC Order D.05-10-042, on September 1, 2006 (or as modified by the CPUC), CPUC-RA Entities are required to make their Year-Ahead System RAR Demonstration for Summer 2007. In addition, beginning April 30, 2006, for June 2006, and monthly thereafter, CPUC-RA Entities are required to demonstrate that they have procured one hundred percent (100%) of their total monthly resource needs on a month-ahead basis for each month ("Month-Ahead System RAR Demonstration"). The Settling Parties anticipate that RA Entities subject to LRA jurisdiction ("LRA-RA Entities") will meet any corresponding requirements and make corresponding demonstrations to the CAISO in compliance with any LRA requirements.

3.2 *RCST Designation for System RAR Demonstration Deficiencies*. After the CAISO has evaluated the Year-Ahead System RAR Demonstrations, the CAISO shall calculate the total deficiencies in MWs. The CAISO may make "System RCST Designations" as follows:

3.2.1 *Year-Ahead Showing.*

(a) If, after the CAISO makes Local RCST designations, there remains a shortfall for Year-Ahead System RAR Demonstrations, the CAISO may designate Eligible Capacity or System Resources to provide RCST service up to the level of the Year-Ahead System Resource Deficiency consistent with the criteria set forth in Section 3.2.3.

(b) Year-Ahead System RCST Designations will have a minimum term of three (3) months, and a maximum term of four (4) months for 2006 (June through September) and five (5) months for 2007 (May through September). In no event shall an RCST

[4] For RA Entities that are not CPUC-RA Entities, the System RA requirement may differ, including the amount that must be demonstrated and the time period in which the demonstration must occur.

designation extend beyond the earlier of midnight on December 31, 2007 or midnight on the day preceding the effective date of the MRTU Tariff.

3.2.2 *Month-Ahead Showing.*

(a) If, after the CAISO makes Local and System Year-Ahead RCST Designations, there remains a net shortfall for Month-Ahead System RAR Demonstrations, the CAISO may designate additional Eligible Capacity or System Resources to provide RCST services consistent with the criteria set forth in Section 3.2.3.

(b) Month-Ahead System RCST Designations will be limited to terms of the lesser of three (3) months or the balance of calendar year. In no event shall an RCST designation extend beyond the earlier of midnight on December 31, 2007 or midnight on the day preceding the effective date of the MRTU Tariff.

3.2.3 The CAISO may issue Year-Ahead or Month-Ahead System RCST Designations to resources internal to the CAISO Control Area or to System Resources; however, System Resources shall be subject to the CAISO's established import limits for Resource Adequacy Requirements purposes as specified in accordance with proposed Section 40.5.2.2 of the CAISO Tariff. The CAISO shall make System RCST Designations by assessing the costs and benefits of such a designation to total grid reliability based upon the unit's effectiveness at resolving local and zonal constraints and the overall cost of the designation, including the number of megawatts procured and Minimum Load Costs and Start Up Costs. The CAISO 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 set forth in this section.

ARTICLE 4

CAISO MUST OFFER OBLIGATION

4.1 *Resource Adequacy Requirements MOO.* Nothing in this Settlement is intended to modify the manner in which RA Resources are, or will be, subject to a must-offer obligation or the compensation that such RA Resources will receive.

4.2 *RMR MOO.* Nothing in this Settlement is intended to modify the manner in which resources subject to RMR contracts are subject to the MOO, if at all, under the current CAISO Tariff, as amended by the CAISO's Tariff amendment filing in Docket No. ER06-723, or the compensation that such RMR resources will receive.

4.3 *RCST MOO.* Capacity designated under the RCST shall be subject to a must-offer obligation to the same extent as RA Resources ("RAR MOO"). Once designated, RCST capacity must offer Ancillary Services to the extent capable.

4.4 *MOWD for System and Local Needs.* For 2006, the parties anticipate that the CAISO will not need to issue MOWDs pursuant to proposed Section 40.7.6 of the CAISO Tariff to Eligible Capacity to meet LARNs or System reliability needs unless Resource Adequacy Resource capacity is unavailable to the CAISO or a Significant Event occurs. For 2006, a "Significant Event" may occur when a material difference in CAISO-Controlled Grid operations occurs relative to what was assumed in developing the 2006 LARN Report and that causes, or threatens to cause, a failure to meet ARC. For 2007, a "Significant Event" may occur when a material difference in CAISO-Controlled Grid operations occurs relative to what was assumed in developing the studies that result in identification of the 2007 Local Reliability Areas and that causes, or threatens to cause, a failure to meet ARC.

4.5 *RCST Trigger for Significant Events*. The CAISO shall assess whether a Significant Event has occurred that warrants an RCST designation prior to making such RCST designation, taking into account the expected duration of the Significant Event. If the CAISO issues a MOWD pursuant to proposed section 40.7.6 of the CAISO Tariff to Eligible Capacity (on a unit-specific basis) on four (4) separate days in any one-year period, the CAISO shall evaluate whether a Significant Event has occurred that warrants an RCST designation (a "MOWD Evaluation"). The CAISO shall conduct a MOWD Evaluation after every four (4) separate days on which the CAISO issues a MOWD pursuant to proposed section 40.7.6 of the CAISO Tariff to Eligible Capacity (on a unit-specific basis) (*i.e.*, an evaluation will occur after the 4th, 8th, 12th, 16th, and so on, days on which a MOWD pursuant to proposed section 40.7.6 of the CAISO Tariff is issued to a specific unit). An RCST designation due to a Significant Event shall have a minimum term of three months and a maximum term of up to the period of time which the CAISO determines that the Significant Event will continue to cause, or threaten to cause, a failure to meet ARC, provided that in no event shall the term of such RCST designation extend beyond the earlier of midnight on December 31, 2007, or midnight of the day before the effective date of MRTU implementation.

ARTICLE 5

MITIGATION

5.1 *System Automatic Mitigation Procedures*. The System Automatic Mitigation Procedures ("System AMP") threshold will be set at two hundred dollars per megawatt hour ($200/MWh), effective June 1, 2006. All resources shall be subject to System AMP.

5.2 *Local Market Power Mitigation.* Local Market Power Mitigation as defined in the CAISO Tariff shall remain unchanged, except as follows: (1) compensation for resource capacity that is mitigated pursuant to the CAISO's Local Market Power Mitigation will be modified as discussed in Section 5.3 herein; and (2) for purposes of determining the Reference Price, the CAISO will use daily gas index prices -- based on 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 is located outside of those three Service Areas, then from the nearest of those Service Areas.

5.3 *Self-Scheduled Unit with Mitigated Supplemental Inc Bid.* The following Generating Units that are Frequently Mitigated shall receive an incremental payment as set forth in this section: (i) Generating Units of Participating Generators for which the CAISO denies a Must Offer Waiver request and for which only a portion of their capacity is Eligible Capacity, and (ii) self-scheduled Generating Units of Participating Generators that have Eligible Capacity. "Frequently Mitigated" means that Eligible Capacity described above has had its Supplemental Incremental bids mitigated for local-area constraints more than four (4) times in a Trading Day. Bid mitigation will be determined on a five-minute dispatch period. Beginning on the ten-minute settlement interval containing the fifth such bid mitigation ("Mitigated Interval"), and continuing for each Mitigated Interval thereafter in that same calendar day, the rate of payment for the mitigated MW amount (*i.e.*, the greater of Mitigated Interval Market Clearing Price ("MCP") or Reference Price for the Dispatched Energy that is mitigated) will be increased to the greater of Mitigated Interval MCP or Reference Price, plus forty dollars per megawatt hour ($40/MWh) ("Frequently Mitigated Adder"), provided that the Frequently Mitigated Adder plus the Mitigated Price shall not exceed the resource's original Supplemental Bid. For Eligible Capacity that does not constitute the total Qualifying Capacity of a specific generating resource ("Partial Unit") and that is self-scheduled under the CAISO Tariff or receives a MOWD pursuant to proposed Section 40.7.6 of the CAISO Tariff, the Frequently Mitigated Adder will be multiplied by the ratio of the Generating Unit's Capacity not under an RA Resource contract (excluding minimum operating level) to the total Qualifying Capacity of the resource.

5.3.1 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 (as established in Section 7.2) if the CAISO had denied a must offer waiver request. Further, Frequently Mitigated Adders will stop accruing in any calendar month once the combined value for that calendar month of Frequently Mitigated Adders, Must Offer Capacity Payments and Minimum Load imbalance energy payments reaches the level of the Monthly RCST Charge (established in Section 6.2.1) reduced by the PER (established in Schedule 6.2.2) for that month multiplied by the megawatts of Eligible Capacity of that Generating Unit.

5.3.2 Frequently Mitigated Adders do not apply to decremental instructions received for local area constraints from the CAISO pursuant to its Tariff.

5.4 *Ancillary Services Procurement.* The CAISO will procure Ancillary Services to meet all WECC MORC requirements, including procuring Ancillary Services zonally as needed, to ensure that the Ancillary Services procured are distributed throughout the CAISO Control Area in such a way that the energy from those Ancillary Services can be fully deployed given the contingencies the Ancillary Services may be required to be used for, congestion, and transmission and resource constraints.

ARTICLE 6

RCST TARGET CAPACITY PRICE, COMPENSATION, AND AVAILABILITY

6.1 *Target Price.* Eligible Capacity that is designated under RCST will receive compensation based on a target annual capacity price that is in turn based on the price of a proxy unit, or "Reference Resource." The Reference Resource is assumed to have the following characteristics: (1) an annual capacity payment of seventy-three dollars per kilowatt-year ($73/kW-yr); (2) an Availability Factor (as defined below) of ninety-five percent (95%) (as defined below); (3) a heat rate of 10,500 BTU/kWh; (4) variable operations and maintenance costs of $3.16/MWh, based on the EIA AEO Electricity Market Module Assumptions; (5) a NOx emissions rate of .009 lb/MMBTU (.0945 lb/MWh) at a price of $7.50/lb or $0.71/MWhr of variable cost adder; and (6) a daily gas price based on 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 & Electric Company), or, if the resource is not served from one of those three Service Areas, then from the nearest of those Service Areas.

6.2 *RCST Capacity Compensation.* The CAISO shall pay providers of RCST service a Monthly RCST Capacity Payment in accordance with the provisions of this Section 6.2, based on the following formula:

Monthly RCST Payment = (Monthly RCST Charge-(Monthly PER x .95)) x Net Qualifying Capacity x Availability Factor

6.2.1 *Monthly RCST Charge.* The CAISO shall calculate a Monthly RCST Charge by multiplying the following Monthly Shaping Factors by the Reference Resource Target

Annual Capacity Price of seventy-three dollars per kilowatt-year ($73/kW-yr):

MONTHLY SHAPING FACTORS

	SP-15	NP-15/ZP-26
Jan	6.7%	4.9%
Feb	5%	4.9%
Mar	5%	5.6%
Apr	5.8%	4.6%
May	6.3%	4.8%
Jun	8.3%	5.1%
Jul	15.8%	13.7%
Aug	17.5%	15.3%
Sept	11.7%	13.8%
Oct	5.8%	8.7%
Nov	6.3%	8.8%
Dec	5.8%	9.8%
Total	**100%**	**100%**

6.2.2 *Calculation of Monthly PER.* The CAISO shall calculate the Monthly Peak Energy Rent ("Monthly PER") as follows:

(a) Immediately following the end of the calendar month, the CAISO shall identify the hours during which the Reference Resource would have been Dispatched (based on Reference Resource characteristics specified in Section 6.1 to provide either Energy or Non-Spinning Reserves), and will calculate, on a per kW-Month basis, the total dollar amount of Rent that would have been earned by the Reference Resource. "Rent" means the earnings in excess of Reference Resource variable costs calculated using Reference Resource unit characteristics specified in Section 6.1.

(b) The CAISO shall assume that the Reference Resource was dispatched for Energy in any hour in which the Hourly Energy Price is greater than the Reference Resource variable cost; the CAISO shall use its day ahead Non-Spinning Reserve price to calculate the Rent for all hours in which the Reference Resource is not assumed to have been dispatched to provide Energy (*i.e.*, any hour where the Hourly Energy Price is less than the Reference Resource's variable costs).

(c) The CAISO shall determine the Hourly Energy Prices profiles by taking the weighted average of: (1) the applicable zonal on/off peak day-ahead index prices set forth in Platts Megawatt Daily, shaped to hourly profiles using the factors in Exhibit A (the "Index Factor"), and (2) the applicable zonal CAISO hourly average real-time energy prices (the "Ex-Post Price Factor"). For 2006, the Index Factor/Ex-Post Price Factor weighting will be 50/50, respectively. For 2007, the Index Factor/Ex-Post Factor weighting will be 75/25, respectively.

6.2.3 *Net Qualifying Capacity*. Net Qualifying Capacity means the Megawatt value for a Generating Unit designated under the RCST, as reflected in the document entitled "Qualifying Capacity MW Values for RA Planning Purposes" (or any successor document) as posted on the CAISO website,[5] provided that, to the extent a particular Generating Unit has more than one stated monthly value, the applicable Net Qualifying Capacity shall be the average of the stated values for the months in which the Generating Unit will have an RCST designation.

6.2.4 *Availability*. Availability means the ratio maximum quantity of Energy or Ancillary Services, in megawatts measured at the Delivery Point, that a resource is capable of producing at the relevant time relative to its Net Qualified Capacity as calculated in accordance with Section 43.7.1 of the Illustrative Tariff Sheets.

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[5] *Available at:* http://www.caiso.com/1796/179694f65b9f0ex.html (last checked March 30, 2006).

(a) RCST Capacity has a target Availability of ninety-five percent (95%). Incentives and penalties for Availability above and below the target are as set forth in the table below, entitled "Availability Factor Table." The "Availability Factor" for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability (excluding only Scheduled Maintenance)	**Capacity Payment Factor**	**Availability Factor**
100%	3.3%	1.139
99%	3.3%	1.106
98%	3.3%	1.073
97%	2.5%	1.040
96%	1.5%	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*	.908-.755
79-41%	-1.9%*	.736-.014
40%	-	0.0

The CAISO shall adjust the Monthly RCST Payment upward from the ninety-five percent (95%) Availability starting point by the positive percentages listed as the Capacity Payment Factor in the above table, by the amounts listed for each Availability factor above ninety-five percent (95%) so that, for example, if a ninety-seven percent (97%) Availability is achieved for the month (as described below), then the Monthly RCST Payment for that month would be the

* The "Capacity Payment Factor" decreases by 1.7% and 1.9% respectively for every 1% decrease in availability in these ranges.

monthly value for ninety-five percent (95%) plus an additional four percent (4%) (one and a half percent (1.5%) for the first percentage of Availability above ninety-five percent (95%), and two and a half percent (2.5%) for the second percentage of Availability above ninety-five percent (95%)). Reductions in Monthly RCST Payment will be made correspondingly according to the Capacity Payment Factor in the above table for monthly Availability levels falling short of the ninety-five percent (95%) Availability starting point.

(b) The CAISO shall calculate Availability on a monthly basis using actual availability data based upon Real-Time operations data.

6.3 *Start-Up and MLCC.* If the RCST Resource has not been self-scheduled in the Day-Ahead or Hour-Ahead Markets and receives an RCST MOWD from the CAISO, the CAISO shall pay such providers of RCST service Start-Up and Minimum Load Cost Compensation ("MLCC") uplift in addition to RCST capacity payments set forth in this Article 6. Such unrecovered MLCC shall be paid as an uplift to the extent that the ten (10) minute Settlement Interval Ex Post Price is insufficient for the resource to recover its Minimum Load Costs.

6.4 *Payment Per CAISO Calendar.* Payments will be consistent with the CAISO Payments Calendar in accordance with section 11.24 of the CAISO Tariff.

6.5 *Limitation on RCST Compensation.* No Party to this Settlement shall seek higher compensation for service under the RCST than is provided for RCST by the terms of this Settlement.

ARTICLE 7

FERC MUST OFFER GENERATOR COMPENSATION

7.1 The CAISO shall continue to make MOO payments to any FERC Must Offer Generator that receives a MOWD pursuant to proposed Section 40.7.6 of the CAISO Tariff consistent with the relevant provisions of the CAISO's current Tariff, as amended by the CAISO's filing in Docket No. ER06-723. Specifically, the CAISO shall make cost-based Start-Up, MLCC, and Imbalance Energy payments for minimum Load energy provided pursuant to a MOWD instruction issued pursuant to proposed Section 40.7.6 of the CAISO Tariff. Nothing in the Settlement is intended otherwise to modify the other aspects of the FERC Must Offer Obligations as specified in Section 40.1 of the CAISO Tariff (proposed Section 40.7), *e.g.*, minimum Load tolerance limits to qualify for MLCC.

7.2 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 Section 6.2.1 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 during that month, (ii) the total Imbalance Energy payments received when that Generating Unit is running at minimum load, and (iii) any Frequently Mitigated Adders accrued during the calendar month, exceeds the Qualifying

Capacity times the maximum Monthly RSCT Charge (established in Section 6.2.1) reduced by the Monthly PER (established in Section 6.2.2), the FERC Must Offer Generator shall not be eligible to receive Must offer capacity Payments or the Frequently Mitigated Adder 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). The Must offer capacity Payment will be made in addition to any Minimum Load, Imbalance Energy, and Start-Up payments.[6]

7.3 The CAISO shall reduce the Monthly Total MOWD Payments on an hourly *pro rata* basis for any period of time in the Trading Day that the Generating Unit was ineligible for the recovery of Minimum Load Costs. Additionally, the CAISO shall reduce Monthly Total MOWD Payments in a manner consistent with existing MOO payment reductions for startup and MLCC payments for failure to meet obligations or operating requirements of a MOWD (*e.g.*, hourly *pro rata* reductions for the hour(s) in question).

ARTICLE 8

RCST REPLACEMENT OPTION

8.1 If a Generating Unit designated under the RCST is unavailable when issued a Must-Offer Waiver Denial by the CAISO pursuant to Section 40.7.6 of the CAISO Tariff, the Scheduling Coordinator for the Generating Unit 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

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[6] Payments made pursuant to Section 7.2 are in addition to MLCC and Start-Up costs. Units continue to receive MOWD Imbalance Energy payments after the maximum Must Offer Capacity Payments have been reached. Payments for Supplemental Energy beyond that produced when operating at minimum Load levels are separate from payments made pursuant to Section 7.2 and do not affect such payments.

Partial Units with any portion of that capacity subject to an RAR obligation are not eligible to receive the one seventeenth (1/17th) payment.

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 CAISO's effectiveness and operational needs, including size of resource, as determined by the CAISO in its reasonable discretion.

8.2 If the RCST Service Provider substitutes a RCST unit, and the CAISO has approved the substitute (if such approval is required), then: (1) the RCST Service Provider must pay all bilateral substitution costs, as well as all additional MLCC, Start-Up and Emissions costs (above the corresponding costs of the Generating Unit that is being substituted); and (2) the actual availability of the substitute resource during the substitute period will be used for purposes of determining Monthly RCST Payment for the original RCST resource.

8.3 If the RCST Service Provider does not substitute a resource, the proposed substitute resource is not approved by the CAISO (if such approval was required), or the approved substitute resource becomes unavailable, then the actual availability of the original RCST resource will be used for purposes of determining the Monthly RCST Payment for the original RCST resource.

ARTICLE 9

RELATIONSHIP BETWEEN RMR AND RCST IN 2007

9.1 The CAISO shall determine its RMR needs and designate units for RMR for 2007 using the same LARS process used in 2006. In this process, the CAISO shall not modify either the need assessment process or the criteria by which it makes RMR designations, and it will not prefer RCST over RMR. The CAISO shall publish the 2007 RMR requirements (including

RMR quantities and, to the extent that the CAISO can make it available, specific resource information) no later than July 1, 2006.

9.2 The CAISO will procure Ancillary Services from RMR resources that switch from the Condition 1 RMR contract to the Condition 2 RMR contract after March 31, 2006, to satisfy Ancillary Services requirements in the same manner that the CAISO has historically used Condition 2 units for Ancillary Services; namely, the cost-based bids of such Condition 2 units will be placed in the Ancillary Services bid stack, and the CAISO will accept bids in the stack in merit order until its Ancillary Services needs are satisfied. The CAISO will not consider the cost-based Ancillary Services bids from an RMR Condition 2 unit that selected Condition 2 prior to March 31, 2006, in the Ancillary Services bid evaluation process.

9.3 The terms of this Settlement will not affect the provisions of the RMR Contract that provide for payment for capital additions that were approved by the CAISO while the RMR Contract with the resource was effective. In the event that the resource is no longer under an RMR Contract, but is designated under the RCST, the capital additions and termination provisions of the RMR Contract will continue to be honored.

ARTICLE 10

REPORTING

10.1 To provide transparency and promote efficiencies, as well as to inform future RAR decisions, the CAISO shall publish the following reports:

10.1.1 *RCST Report.* The CAISO shall publish a monthly report on the CAISO website that 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 10.1.3 herein, in dollars, itemized for system purposes as well as for each Local Reliability Area or 2007 Local Reliability Area, whichever is applicable. The CAISO will provide a Market Notice of the availability of this report.

10.1.2 *Daily MOWD Report.* The MOWD Report shall identify the purposes for which MOWD were issued by category and the amount of megawatts involved in each category, *i.e.*, local, zonal, or system. The CAISO shall publish the MOWD Report on its website on a weekly basis, and the CAISO shall provide a Market Notice of its availability. On a daily basis, thirty (30) days after the Trading Day, the CAISO will publish on OASIS the allocation of MLCC Uplift, Minimum Load Costs for resources under RA, RCST, and Eligible Capacity.

10.1.3 *Monthly Minimum Load Cost Report.* On a monthly basis, thirty (30) days after the Trading Day, the CAISO will publish on OASIS, the allocation of MLCC Uplift, Minimum Load Costs for resources under RA, RCST, and Eligible Capacity.

10.1.4 *Significant Event/MOWD Report.* The CAISO shall publish the results of its assessment of a Significant Event or MOWD Evaluation ("Significant Event/Repeat MOWD Report"), including an explanation as to its decision to either designate or not designate Eligible Capacity as RCST, on its website on a weekly basis unless no Significant Events or MOWD evaluations occurred during the week; the CAISO will provide a Market Notice of the availability of each Significant Event/Repeat MOWD Report. The Significant Event Report shall explain why the CAISO issued the MOWDs pursuant to proposed Section 40.7.6 of the CAISO Tariff that triggered the assessment of whether a Significant Event occurred, and whether other generation units with RAR contracts, RMR Contracts, or existing RCST Designations were available and called upon by the CAISO prior to its issuance of its MOWDs pursuant to proposed Section 40.7.6 of the CAISO Tariff to the Eligible Capacity. If Non-Generation Solutions were adopted by the CAISO to reduce local area needs, the CAISO shall also explain why the Non-Generation Solution was insufficient to prevent the use of a MOWD pursuant to proposed Section 40.7.6 of the CAISO Tariff for local reasons. In the event that the CAISO issues a MOWD pursuant to proposed Section 40.7.6 of the CAISO Tariff for Local or System purpose other than a Significant Event, the report shall include an explanation for such issuance and shall be signed by the CAISO's Vice President of Operations.

ARTICLE 11

RCST SELECTION AND OBLIGATIONS

11.1 *RCST Selection.* The CAISO may designate Eligible Capacity under the RCST, in accordance with the limits provided in this Settlement, up to the Qualifying Capacity of the applicable generating unit. The CAISO shall use the criteria provided above in the Sections 2.2.5 and 3.2.3 to make RCST designations in order to achieve the lowest overall cost for RCST designations. The CAISO shall be open and transparent about the factors and processes used to make RCST Designations to the maximum extent permissible under law.

11.2 *Obligations.*

11.2.1 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 notice to withdraw from the Participating Generator Agreement ("PGA"), then the Participating Generator shall be obligated pursuant to the RCST provisions of the CAISO Tariff for the term of the RCST designation.

11.2.2 If a Participating Generator's Eligible Capacity is designated under the terms of the RCST after the Participating Generator filed notice to withdraw from its PGA, then the Participating Generator shall provide service under the RCST until the date that its PGA effectively terminates, but the Participating Generator shall be under no obligation pursuant to the RCST provisions of the CAISO Tariff after the date that its PGA effectively terminates.

11.2.3 If a Participating Generator's RCST Eligible Capacity is designated under the terms of 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 provisions of the CAISO Tariff, then the Participating Generator will enter into a PGA for the designated generating unit and invoice the CAISO for any actual applicable restoration costs as provided in the RMR Contract.

ARTICLE 12

COST ALLOCATION

12.1 *System RCST Designations.* The CAISO shall allocate the cost of System RCST Designations to the SC-RA Entity[7] for each of its deficient RA Entities based on the ratio of such RA Entity's deficiency relative to total RA Entity deficiencies for the respective deficiency period in the CAISO Control Area.

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7 *See* footnote 2.

12.2 Local RCST Designations.

12.2.1 *2006 Cost Allocation.* The CAISO shall apportion the RCST procurement costs for Local RCST Designations in 2006 to SC-RA Entities[8] in order to credit SC-RA Entities for the local resources that they provide to the CAISO, as evidenced through their LARN Demonstrations, using the following process:

(a) The CAISO will determine a Gross LARN Allocation amount for each SC-RA Entity by multiplying the Scheduling Coordinator's RA Entity's Load Share Percentage in the TAC Area by the sum of: (a) all LARN Credits in the TAC Area for all SC-RA Entities and (b) the total megawatts of RCST designations in the TAC Area made pursuant to Section 43.2.1 of the Illustrative Tariff Sheets.

(b) The CAISO will determine a Net LARN Allocation amount for each SC-RA Entity by subtracting the LARN Credits for that SC-RA Entity from its Gross LARN Allocation amount determined in accordance with Section 43.8(3)(a) of the Illustrative Tariff Sheets. If a SC-RA Entity's LARN Credits are greater than its LARN Allocation amount as determined in accordance with Section 43.2.1.1 of the Illustrative Tariff Sheets, then the SC-RA Entity's Net LARN Allocation amount shall be zero.

© The CAISO will determine, for each TAC Area, the "2006 TAC Area Tier 1 Local RCST MW Total," which is the lesser of: (1) the difference between the LARN in the TAC Area and the sum of all LARN Credits in the TAC Area for all SC-RA Entities (if zero or greater); or (2) the sum of the RCST designations for 2006 under Section 43.2.1 of the

8 *See id.*

Illustrative Tariff Sheets, in that TAC Area. The "2006 TAC Area Tier 2 Local RCST MW Total" for that TAC Area shall be the remainder (in megawatts) of the RCST designations for 2006 under Section 43.2.1 of the Illustrative Tariff Sheets, in that TAC Area, if any.

(d) The CAISO shall calculate "2006 Tier 1 Level RCST Costs" by multiplying the total RCST Capacity Payments to Generating Units in the TAC Area designated under Section 43.2.1 of the Illustrative Tariff Sheets, by the percentage that the 2006 TAC Area Tier 1 RCST MW Total represents of the total MW quantity of RCST designations for 2006 under Section 43.2.1 of the Illustrative Tariff Sheets in that TAC Area. The remaining costs for RCST Capacity Payments to Generating Units in the TAC Area shall be "2006 TAC Area Tier 2 RCST Costs."

(e) The CAISO will allocate the 2006 Tier 1 Local RCST Costs for each TAC Area to SC-RA Entities in that TAC Area in proportion to the ratio of each SC-RA Entity's Net LARN Allocation to the total Net LARN Allocation for all SC-RA Entities for that TAC Area as determined in accordance with Section 43.8(3)(b) of the Illustrative Tariff Sheets.

(f) The CAISO will allocate the 2006 Tier 2 Local RCST Costs for each TAC Area to all SC-RA Entities in that TAC Area based on Scheduling Coordinator's RA Entity's Load Share Percentage(s) in the TAC Area.

Attachment B provides specific examples for 2006.

12.2.2 *2007 Cost Allocation*. Reserved pending the establishment of local resource adequacy requirements by the CPUC and LRAs for 2007.

12.3 *RCST Designations Triggered By Significant Events*. Costs for Local RCST

Designations triggered by Significant Events will be allocated to all SC- RA Entities in the TAC Area(s) in which the Significant Event causes, or threatens to cause, a failure to meet ARC, based on a Scheduling Coordinator's RA-Entity's Load Share Percentage in such TAC Area(s). The allocation methodology is reserved for 2007 pending the establishment of local resource adequacy requirements by the CPUC and LRAs for 2007.

12.4 *MOO Costs*. MOO Start-up and MLCC will be allocated in accordance with the final FERC decision in the Amendment No. 60 proceeding, Docket No. ER04-835-000. The Must Offer Capacity Payments associated with units that receive a MOWD pursuant to proposed Section 40.7.6 of the CAISO Tariff shall be allocated in a manner consistent with the way MLCC costs are allocated in accordance with that FERC decision. The Settlement does not change the method in which Imbalance Energy Payments are allocated.

12.5 *Frequently Mitigated Unit Cost Allocation*. The costs associated with Frequently Mitigated units shall be allocated using the Grid Operations Charge methodology set forth in the CAISO Tariff.

12.6 *RA Credit for RCST*. To the extent allowed by the CPUC or LRA, an SC-RA Entity may count RCST capacity for which it was allocated costs towards its RAR obligation for the term of the RCST designation.

ARTICLE 13

EFFECTIVE DATE

13.1 This Settlement shall become effective upon issuance by the Commission of a Final Order approving this Settlement without modification or condition, or if modified or conditioned, upon its acceptance as so modified by the Settling Parties as provided in Section 14.1.3 below.

13.2 For purposes of this Settlement, a Commission order shall be deemed to be a Final Order when the Commission issues an order approving this Settlement.

ARTICLE 14

MISCELLANEOUS

14.1 Termination of Settlement.

14.1.1 The CAISO Tariff provisions implementing the terms of this Settlement shall automatically expire the on earlier of: (a) midnight on December 31, 2007, or (b) midnight on the date immediately before the CAISO's Market Redesign and Technology Update ("MRTU") Tariff becomes effective pursuant to FERC Order, except that provisions concerning compensation, cost allocation, and settlement will 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 CAISO has finally allocated and recovered the costs associated with such RCST compensation. In the event MRTU is not implemented by December 31, 2007, effective January 1, 2008, the AMP price screen, as reflected in Appendix P, Attachment A, Section 4.2.2(e), shall revert to $91.87/MWh from $200/MWh.

14.1.2 If the Commission, in approving this Settlement or by taking any other regulatory action, or if any other regulatory action modifies the Settlement in a manner that materially changes the benefits and burdens negotiated herein, the Settling Parties shall meet and confer as to whether all Settling Parties can agree to the modified Settlement. If all of the Settling Parties do not agree, in writing, to the modified Settlement, then the Settlement and the

CAISO Tariff provisions implementing the terms of the Settlement shall terminate, except that provisions concerning compensation, cost allocation, and settlement will 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 CAISO has finally allocated and recovered the costs associated with such RCST compensation.

14.2 *CPUC Proceeding R.05-12-013.* Nothing in this Settlement predetermines what the CPUC may do in R.05-12-013 or any other proceeding, or alters any CPUC jurisdictional rights, including, without limitation, the CPUC's jurisdiction regarding cost allocation and compensation schemes among CPUC-jurisdictional RA Entities regarding resource adequacy requirements imposed by the CPUC.

14.3 *Precedential Value.* The Settling Parties agree that this Settlement shall have no precedential value, shall not be cited as precedent, and shall not be deemed to bind any Settling Party (except as otherwise expressly provided for herein) in any future proceeding, including any future FERC proceeding, except in any proceeding to enforce this Settlement. The Settling Parties further agree that this Settlement shall not be deemed to be a "settled practice" as that term was interpreted and applied in *Public Service Commission of the State of New York v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980).

14.4 *Negotiated Settlement.* This Settlement is made upon the express understanding that it constitutes a negotiated settlement and, except as otherwise expressly provided for herein, no Settling Party shall be deemed to have approved, accepted, agreed to, or consented to any principle or policy relating to the rates, charges, classifications, terms, conditions, principles, issues or tariff sheets associated with this Settlement.

14.5 *Integration.* The Exhibits to this Settlement are hereby integrated into, and shall constitute part of, this Settlement.

14.6 *Entire Agreement.* The Settling Parties acknowledge and agree that this Settlement, including the Exhibits hereto, constitutes the full and complete agreement of the Settling Parties with respect to the subject matter addressed herein and supercedes all prior negotiations, understandings, and agreements, whether written or oral, between the Settling Parties with respect to the subject matter addressed herein.

14.7 *Standard of Review.* The Settling Parties intend for this Settlement to be subject to the just and reasonable standard of review.

14.8 *Settlement Privilege.* The Settling Parties agree that the discussions among them that have produced this Settlement have been conducted on the explicit understanding that they were undertaken subject to Rule 602(e) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602(e). The Settling Parties further agree that all offers of settlement, and any comments on such offers, and any discussions among the Settling Parties with respect to this Settlement are privileged, not admissible as evidence against any participant who objects to their admission, and not subject to discovery.

14.9 *Support for Settlement/No Waiver of Rights.* The Settling Parties shall support this Settlement and shall cooperate in securing Commission acceptance and implementation of this Settlement. The Settling Parties hereby waive any and all rights to seek rehearing or judicial review of any Commission order(s) approving the Settlement without modification or condition; provided, however, that if the Commission approves the Settlement with modifications or conditions, any Party may seek rehearing or judicial review of the Commission order(s) approving the Settlement solely to challenge the Commission's imposition of such modifications or conditions in order to preserve the terms and conditions of the Settlement as filed. Notwithstanding any other provision of this Offer of Settlement, no party waives its rights under Section 205 or 206 of the Federal Power Act with respect to any provision of the CAISO Tariff.

14.10 *Headings*. Headings in this Settlement are included for convenience only and are not intended to have any significance in interpretation of this Settlement.

14.11 *Dispute Resolution.* Dispute resolution shall be in accordance with the CAISO Tariff.

Respectfully submitted,

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ATTACHMENT A

Attachment A(1)

Clean Tariff Sheets

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

(f) the ISO will (to the extent available) procure sufficient Ancillary Services to meet its requirements;

(g) the ISO will evaluate and price only those Ancillary Services bids received; and

(h) Until the earlier of the midnight of day before the effective date of the MRTU Tariff or midnight on December 31, 2007, the ISO will not consider in the Ancillary Service bid evaluation process the Ancillary Services bids of Condition 2 RMR resources that are Condition 2 prior to March 31, 2006. This Section 8.5.4 (h) shall expire at midnight on the earlier of December 31, 2007 or the date immediately before the MRTU goes into effect.

8.5.5 Evaluation of Ancillary Services Bids.

When Scheduling Coordinators bid into the Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve markets, they may bid the same capacity into as many of these markets as desired at the same time by providing the appropriate bid information to the ISO. The ISO shall evaluate bids in the markets for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve sequentially and separately in the following order: Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve. Any capacity accepted by the ISO in one of these markets shall not be passed on to another market, except that capacity accepted in the Regulation market that represents the downward range of movement accepted by the ISO may be passed on to another market; any losing bids in one market may be passed onto another market, if the Scheduling Coordinator so indicates to the ISO. A Scheduling Coordinator may specify capacity bid into only the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices and different Energy prices for the Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Regulation markets. The bid information, bid evaluation and price determination rules set forth below shall be used in the Day-Ahead, Hour-Ahead and real-time procurement of Regulation, Spinning Reserve, Non- Spinning Reserve, and Replacement Reserve.

A Scheduling Coordinator providing one or more Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve services may not change the identification of the Generating Units or

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

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 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 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 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 43.9 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 RSCT 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 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 of 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. If Non-Generation Solutions were adopted by the ISO to reduce LARN pursuant to Section 43.2.1.1 above, the ISO shall also explain why the Non-Generation Solution was 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.

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. ER06-146 (changes to Sections 8.5.4; 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 2006 Local RCST Designations

43.2.1.1 Determination of Responsibility for Local Area Reliability Needs

The ISO shall determine the RA Entity Load Share Percentage for each RA Entity. The RA Entity Load Share Percentage shall be calculated for each RA Entity by dividing the RA Entity's actual annual coincident peak Load in each TAC Area in 2005 ("RA Entity Load Share") by the total coincident peak Load of all RA Entities in the TAC Area in 2005 ("Total TAC Load"). The ISO will calculate a RA Entity's LARN Allocation in a TAC Area by multiplying, for each TAC Area, the RA Entity Load Share Percentage by the LARN in the TAC Area.

43.2.1.2 LARN Demonstrations and Crediting

The ISO will provide a Scheduling Coordinator for a RA Entity ("SC-RA Entity") with a LARN Credit for each MW of capacity in a RA Entity's LARN Demonstration that meets the following requirements: (1) the capacity is provided to the ISO under the same terms and conditions as Resource Adequacy Resources under Section 40.6A, and (2) the capacity either (a) qualifies as a Local Area Resource, or is (b) Qualifying Capacity for a Generating Unit or Participating Load that is a Resource Adequacy Resource identified in a RA Entity's Resource Adequacy Plan and which is located in a Local Reliability Area.

The ISO will provide a LARN Credit to account for RMR megawatts paid by an RA Entity as set forth below. PTOs will provide the ISO with the necessary information to enable the ISO to calculate the proportion of RMR megawatts paid for by the RA Entity ("RA Entity RMR MW Number") as follows: (i) for RMR Units that have fixed costs paid through either Annual Fixed Reliability Costs ("AFRC"), or Annual Fixed Revenue Requirement ("AFRR") multiplied by a Fixed Option Payment Factor ("FOPF") -- as defined in applicable RMR agreements -- by applying the RA Entity's percentage of responsibility for such costs as assessed through PTO FERC tariffs, or (ii) for RMR Units that have the full functional equivalent of AFRC or AFRR multiplied by FOPF paid by an RA Entity through a Resource Adequacy Resource contract that requires AFRC or AFRR multiplied by FOPF be set to zero, by applying 100% to the RA Entity paying such costs through the contract. To the extent PTOs do not provide the ISO with the information necessary to calculate the RA Entity RMR MW Number, as described above, the ISO shall calculate the RA Entity RMR MW Number based on RA Entity Load Share Percentage.

The ISO will also provide a SC-RA Entity with a LARN Credit for each MW of Participating Load and Distributed Generation that is dispatchable by the ISO that are in an RA Entity's LARN Demonstration and which are located in a Local Reliability Area. For purposes of this section, Distributed Generation is the capacity of generating units that are connected to the distribution facilities of load serving entities.

43.2.1.3 Determination of LARN Credits

Following the ISO's review of any LARN Demonstrations that a SC-RA Entity submits to the ISO in accordance with the criteria set forth in Section 43.2.1.2, the ISO will inform each SC-RA Entity of the amount of LARN Credit that it will receive against its LARN Allocation.

43.2.1.4 Residual LARN Determination Report

By May 24, 2006, the ISO will issue a report detailing: (1) the ISO's evaluation of the LARN Demonstrations of all RA Entities, including a determination of the Effectiveness of all resources in the LARN Demonstrations; (2) if relevant, the reasons that the aggregate LARN Demonstrations of all RA Entities, combined with RMR Units and Resource Adequacy Resources, have not satisfied the LARN in any Local Reliability Area, and (3) the amount of any Residual LARN in any Local Reliability Area.

43.2.1.5 RCST Designation for Residual LARN

No sooner than May 24, 2006, the ISO may designate Eligible Capacity that qualifies as a Local Area Resource to provide services under the RCST to the extent necessary to cover the Residual LARN amount, consistent with the criteria specified in Section 43.2.3. RCST designations under this Section shall be for a term that commences no sooner than June 1, 2006, and terminates at midnight on December 31, 2006.

43.2.2 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. 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 the 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. Following both the CAISO's identification of any Local Resource Adequacy Requirement Deficiency and any CPUC or Local Regulatory Authority-established opportunity to correct such deficiency, the ISO may designate Eligible Capacity to provide services under the RCST consistent with the criteria set forth in Section 43.2.3, taking into account all RMR and Resource Adequacy Resources that will be made available to the ISO in 2007, whether or not any of those resources are located in the 2007 Local Reliability Area. The ISO may designate Eligible Capacity to provide service under this Section 43.2.2 to the extent necessary to cover 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. 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 MRTU Tariff.

43.2.3 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 TAC Area or 2007 Local Reliability Area, whichever is applicable, 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 2006, any designation of Eligible Capacity pursuant to Section 43.2.1.5 for 2006 or, for 2007, any designation of Eligible Capacity pursuant to Section 43.2.2, 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 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 of 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 shall also, to the extent that they have any available capacity not designated under RCST or under contract as a Resource Adequacy Requirements resource, offer such capacity into the next available Ancillary service markets.

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 as well as 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 2006: If the ISO makes local designation under RCST for 2006 under Section 43.2.1, then the ISO will allocate the total costs of RCST Capacity Payments for such designations as follows:

a. The ISO will determine a Gross LARN Allocation amount for each SC-RA Entity by multiplying the Scheduling Coordinator's RA Entity's Load Share Percentage in the

TAC Area by the sum of (a) all LARN Credits in the TAC Area for all SC-RA Entities and (b) the total megawatts of RCST designations in the TAC Area made pursuant to Section 43.2.1.

b. The ISO will determine a Net LARN Allocation amount for each SC-RA Entity by subtracting the LARN Credits for that SC-RA Entity from its Gross LARN Allocation amount determined in accordance with Section 43.8(3)(a). If a SC-RA Entity's LARN Credits are greater than its LARN Allocation amount as determined in accordance with Section 43.2.1.1, then the SC-RA Entity's Net LARN Allocation amount shall be zero.

c. The ISO will determine, for each TAC Area, the "2006 TAC Area Tier 1 Local RCST MW Total," which is the lesser of (1) the difference between the LARN in the TAC Area and the sum of all LARN Credits in the TAC Area for all SC-RA Entities (if zero or greater); (2) the sum of the RCST designations for 2006 under Section 43.2.1, in that TAC Area. The "2006 TAC Area Tier 2 Local RCST MW Total" for that TAC Area shall be the remainder (in megawatts) of the RCST designations for 2006 under Section 43.2.1, in that TAC Area, if any.

d. The ISO shall calculate "2006 Tier 1 Level RCST Costs" by multiplying the total RCST Capacity Payments to Generating Units in the TAC Area designated under Section 43.2.1, by the percentage that the 2006 TAC Area Tier 1 RCST MW Total represents of the total MW quantity of RCST designations for 2006 under Section 43.2.1 in that TAC Area. The remaining costs for RCST Capacity Payments to Generating Units in the TAC Area shall be "2006 TAC Area Tier 2 RCST Costs."

e. The ISO will allocate the 2006 Tier 1 Local RCST Costs for each TAC Area to SC-RA Entities in that TAC Area in proportion to the ratio of each SC-RA Entity's Net LARN Allocation to the total Net LARN Allocation for all SC-RA Entities for that TAC Area as determined in accordance with Section 43.8(3)(b).

f. The ISO will allocate the 2006 Tier 2 Local RCST Costs for each TAC Area to all SC-RA Entities in that TAC Area based on Scheduling Coordinator's RA Entity's Load Share Percentage(s) in the TAC Area.

(4) Local RCST Designations for 2007.

[Reserved]

(5) 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 Coordinator's RA Entity's Load Share Percentage(s) in such TAC Area(s).

(6) Significant Event Designations for 2007:

[Reserved]

	account, and determining the price for mitigating Congestion for flows on Congested paths. The formula for determining the Congestion Management Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.
Congestion Zone	A Zone identified as an Active Zone in Appendix I of the ISO Tariff.
Connected Entity	A Participating TO or any party that owns or operates facilities that are electrically interconnected with the ISO Controlled Grid.
Constrained Output Generation	Generating resources with only two viable operating states: (a) off-line or (b) operating at their maximum output level.
Constraints	Physical and operational limitations on the transfer of electrical power through transmission facilities.
Contingencies of Concern	For 2006, contingencies evaluated by the ISO in the study that resulted in the LCR Report that caused the ISO to identify an area as a Local Reliability Area.
Contingency	Disconnection or separation, planned or forced, of one or more components from an electrical system.
Control Area	An electric power system (or combination of electric power systems) to which a common AGC scheme is applied in order to: i) match, at all times, the power output of the Generating Units within the electric power system(s), plus the Energy purchased from entities outside the electric power system(s), minus Energy sold to entities outside the electric power system, with the Demand within the electric power system(s); ii) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and iv) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Area Gross Load For the purpose of calculating and billing Minimum Load Costs, Emission Costs Charge and Start-Up Fuel Costs Charge, Control Area Gross Load is all Demand for Energy within the ISO Control Area. Control Area Gross Load shall not include Energy consumed by:

(a) generator auxiliary Load equipment that is dedicated to the production of Energy and is electrically connected at the same point as the Generating Unit (e.g., auxiliary Load equipment that is served via a distribution line that is separate from the switchyard to which other prices used to settle Imbalance Energy.

Dispatch Operating Point The expected operating point of a resource that has received a Dispatch Instruction. The resource is expected to operate at the Dispatch Operating Point after completing the Dispatch Instruction, taking into account any relevant ramp rate and time delays. Energy expected to be produced or consumed above or below the Final Hour-Ahead Schedule in response to a Dispatch Instruction constitutes Instructed Imbalance Energy. For resources that have not received a Dispatch Instruction, the Dispatch Operating Point defaults to the corresponding Final Hour-Ahead Schedule.

Dispatchable Load Load which is the subject of an Adjustment Bid.

Distribution System The distribution assets of an IOU or Local Publicly Owned Electric Utility.

Distribution Upgrades The additions, modifications, and upgrades to the Participating TO's electric systems that are not part of the ISO Controlled Grid. Distribution Upgrades do not include Interconnection Facilities.

Dynamic Schedule A telemetered reading or value which is updated in real time and which is used as a schedule in the ISO EMS calculation of ACE and the integrated value of which is treated as a schedule for interchange accounting purposes.

EEP (Electrical Emergency Plan) A plan to be developed by the ISO in consultation with UDCs to address situations when Energy reserve margins are forecast to be below established levels.

Effectiveness The ability of a resource to address one or more Contingencies of Concern affecting a Local Reliability Area expressed as a percentage with respect to each relevant Contingency of Concern of the ability of the most effective resource to address that contingency.

Electronic Data Interchange (EDI)	The routine exchange of business documented on electronic media such as purchase orders, invoices and remittance. The format of the data is based on an industry-approved format such as those published by the ANSI ASC X12 committee.
Eligible Capacity	Capacity of Generating Units of Participating Generators located within the ISO Control Area except the following: capacity associated with hydroelectric generation, nuclear generation, QFs, generation resources within a Metered Subsystem, resources owned by the California Department of Water Resources, State Water Project; capacity of a Generating Unit with a Reliability Must-Run contract, during the term of such contract; capacity of a Resource Adequacy Resource that is identified in any Resource Adequacy Plan in accordance with Section 40, during the time that such capacity is identified on the Resource Adequacy Plan; and capacity that has been designated to provide serve under the RCST, during the term of the designation.
Eligible Customer	(i) any utility (including Participating TOs, Market Participants and any power marketer), Federal power marketing agency, or any person generating Energy for sale or resale; Energy sold or produced by such entity may be Energy produced in the United

ISP (Internet Service Provider)	An independent network service organization engaged by the ISO to establish, implement and operate WEnet.
Large Generating Facility	A Generating Facility having a Generating Facility Capacity of more than 20 MW.
Line Loss Correction Factor	The line loss correction factor as set forth in the Technical Specifications.
Load	An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires.
Load-Serving Entity (LSE)	Any entity (or the duly designated agent of such an entity, incuding, e.g. a Scheduling Coordinator), including a load aggregator or power marketer; (i) serving End Users within the ISO Control Area and (ii) that has been granted authority or has an obligation pursuant to California State or local law, regulation, or franchise to sell electric energy to End Users located within the ISO Control Area or (iii) is a Federal Power Marketing Authority that serves retail Load.
Load Shedding	The systematic reduction of system Demand by temporarily decreasing the supply of Energy to Loads in response to transmission system or area capacity shortages, system instability, or voltage control considerations.
Local Area Reliability Needs (LARN)	As identified in the LARN Report for 2006, the amount of generation (in MW) needed for a Local Reliability Area in order to satisfy Applicable Reliability Criteria in 2006.
Local Area Reliability Needs Allocation (LARN Allocation)	The ISO's allocation of responsibility, expressed in MW, to each RA Entity represented by a Scheduling Coordinator for the LARN in each TAC Area(s) within which the RA Entity serves Load.
Local Area Reliability Needs Credit (LARN Credit)	The amount by which an RA Entity's LARN Allocation will be reduced in accordance with the criteria in Section 43.2.1.2.
Local Area Reliability Needs Demonstration (LARN Demonstration)	The demonstration made to the ISO by a Scheduling Coordinator for an RA Entity of the resources that the RA Entity will make available to the ISO to satisfy the LARN.

LARN Report for 2006	The report, published by the ISO, which identifies each Local Reliability Area, the contingencies that require the ISO to specify a geographically contiguous area as a Local Reliability Area, and the amount of generation (in MW) needed for each Local Reliability Area in order to satisfy Applicable Reliability Criteria, taking into account Non-Generation Solutions.
Local Area Resource	A Local Area Resource is a Generating Unit located in a Local Reliability Area that has a material degree of Effectiveness.
Local Furnishing Bond	Tax-exempt bonds utilized to finance facilities for the local furnishing of electric energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).
Local Furnishing Participating TO	Any Tax-Exempt Participating TO that owns facilities financed by Local Furnishing Bonds.
Local Publicly Owned Electric Utilities	A municipality or municipal corporation operating as a public utility furnishing electric service, a municipal utility district furnishing electric service, a public utility district furnishing electric services, an irrigation district furnishing electric services, a state agency or subdivision furnishing electric services, a rural cooperative furnishing electric services, or a joint powers authority that includes one or more of these agencies and that owns Generation or transmission facilities, or furnishes electric services over its own or its members' electric Distribution System.
Local Regulatory Authority	The state or local governmental authority responsible for the regulation or oversight of a utility.
Local Reliability Area	For 2006, a geographically contiguous area within a TAC Area that the CAISO has determined, through reliability studies, requires Local Area Resources to meet Applicable Reliability Criteria.
Local Reliability Criteria	Reliability Criteria unique to the transmission systems of each of the PTOs established at the later of: (1) ISO Operations Date, or (2) the date upon which a New Participating TO places its facilities under the control of the ISO.

Local Reliability Criteria	Reliability Criteria established at the ISO Operations Date, unique to the transmission systems of each of the Participating TOs.
Local Resource Adequacy Demonstration	The demonstration made to the ISO by the Scheduling Coordinator for a RA Entity of the resources that the RA Entity will make available to the ISO to satisfy Local Resource Adequacy Requirements.
Local Resource Adequacy Requirement	The Resource Adequacy Requirement established by the CPUC or a Local Regulatory Authority in a 2007 Local Reliability Area (or for 2007 Local Reliability Areas in the aggregate) for each RA Entity subject to their jurisdiction.
Local Resource Adequacy Requirement Deficiency	The difference in MWs between the sum of Local Resource Adequacy Requirements for RA Entities in a given 2007 Local Reliability Area and the quantity of MWs shown in RA Entities' Local Resource Adequacy Demonstrations for that 2007 Local Reliability Area.
Location Code	The code assigned by the ISO to Generation input points, and Demand Take-Out Points from the ISO Controlled Grid, and transaction points from trades between Scheduling Coordinators. This will be the information used by the ISO Controlled Grid, and transaction points for trades between Scheduling Coordinators. This will be the information used by the ISO to determine the location of the input, output, and trade points of Energy Schedules. Each Generation input and Demand Take-Out Point will have a designated Location Code identification for use in submitting Energy and Ancillary Service bids and Schedules.
Loop Flow	Energy flow over a transmission system caused by parties external to that system.
Loss Scale Factor	The ratio of expected Transmission Losses to the total Transmission Losses which would be collected if Full Marginal Loss Rates were utilized.
Low Voltage Access Charge	The Access Charge applicable under Section 26.1 to recover the Low Voltage Transmission Revenue Requirement of a Participating TO.

Low Voltage Transmission Facility	A transmission facility owned by a Participating TO or to which a Participating TO has an Entitlement that is represented by a Converted Right, which is not a High Voltage Transmission Facility, that is under the ISO Operational Control.
Low Voltage Transmission Revenue Requirement	The portion of a Participating TO's TRR associated with and allocable to the Participating TO's Low Voltage Transmission Facilities and Converted Rights associated with Low Voltage Transmission Facilities that are under the ISO Operational Control.

	under terms approved by a Local Regulatory Authority or FERC, as applicable, or the customer's Load can be curtailed concurrently with an outage of the Generating Unit.
Meter Data Exchange Format	The format for submitting Meter Data to the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.
Meter Data Request Format	The format for requesting Settlement Quality Meter Data from the ISO which will be published by the ISO on the ISO Home Page or available on request to the Meter and Data Acquisition Manager, ISO Client Service Department.
Metered Quantities	For each Direct Access End-User, the actual metered amount of MWh and MW; for each Participating Generator the actual metered amounts of MWh, MW, MVAr and MVArh.
Metering Facilities	Revenue quality meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication facilities and other related local equipment.
Minimum Load Costs	The costs a Generating Unit incurs operating at minimum load.
Month-Ahead System Resource Adequacy Requirements	The amount of Qualifying Capacity that a RA Entity must reflect in its monthly Resource Adequacy Plan submitted pursuant to Section 40.2.2 in compliance with Resource Adequacy Rules adopted by the CPUC or a Local Regulatory Authority, as applicable.
Month-Ahead System Resource Deficiency	The monthly deficiency in meeting the Month-Ahead System Resource Adequacy Requirements as determined by the CPUC and applicable Local Regulatory Authorities for each RA Entity subject to their jurisdiction.
Monthly Peak Load	The maximum hourly Demand on a Participating TO's transmission system for a calendar month, multiplied by the Operating Reserve Multiplier.
Monthly RCST Charge	The monthly charge determined in accordance with Appendix F, Schedule 6.

MRTU Tariff	The ISO Tariff that will implement the ISO's Market Redesign and Technology Upgrade ("MRTU").
MSS (Metered Subsystem)	A geographically contiguous system located within a single Zone which has been operating as an electric utility for a number of years prior to the ISO Operations Date as a municipal utility, water district, irrigation district, State agency or Federal power administration subsumed within the ISO Control Area and encompassed by ISO certified revenue quality meters at each interface point with the ISO Controlled Grid and ISO certified revenue quality meters on all Generating Units or, if aggregated, each individual resource and Participating Load internal to the system, which is operated in accordance with a MSS Agreement described in Section 4.9.1.
MSS Operator	An entity that owns an MSS and has executed a MSS Agreement.
Municipal Tax Exempt Debt	An obligation the interest on which is excluded from gross income for federal tax purposes pursuant to Section 103(a) of the Internal Revenue Code of 1986 or the corresponding provisions of prior law without regard to the identity of the holder thereof. Municipal Tax Exempt Debt does not include Local Furnishing Bonds.

Must-Offer Capacity Payment	The payment made in accordance with Section 43.9 of this ISO Tariff.
Native Load	Load required to be served by a utility within its Service Area pursuant to applicable law, franchise, or statute.
NERC	The North American Electric Reliability Council or its successor.
Net FTR Revenue	The sum of: 1) the revenue received by the New Participating TO from the sale, auction, or other transfer of the FTRs provided to it pursuant to Section 36.4.3 FTR, or any substantively identical successor provision of the ISO Tariff; and 2) for each hour: a) the Usage Charge revenue received by the New Participating To associated with its Section 36.4.3 FTRs; minus b) Usage Charges that are: i) incurred by the Scheduling Coordinator for the New Participating TO under ISO Tariff Section 27.1.2.1.4 ii) associated with the New Participating TO's Section 36.4.3 FTRs, and iii) incurred by the New Participating TO for its energy transactions but not incurred as a result of the use of the transmission by a third-party and minus c) the charges paid by the New Participating TO pursuant to Section 27.1.2.1.7, to the extent such charges are incurred by the Scheduling Coordinator of the New Participating TO on Congested Inter-Zonal Interfaces that are associated with the Section 36.4.3 FTRs provided to the New Participating TO. The component of New FTR Revenue represented by item 2) immediately above shall not be less than zero for any hour.
Net Negative Uninstructed Deviation	The real-time change in Generation or Demand associated with underscheduled Load (i.e., Load that appears unscheduled in real time) and overscheduled Generation (i.e., Generation that is scheduled in forward markets and does not appear in real time). Deviations are netted for each Settlement Interval, apply to a Scheduling Coordinator's entire portfolio, and include Load, Generation, imports and exports.
Net Qualifying Capacity	Qualifying capacity reduced, as applicable, based on: (1) testing and verification; and (2) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the ISO pursuant to the provisions of this ISO Tariff and any applicable manual or procedure.

Network Upgrades	The additions, modifications, and upgrades to the ISO Controlled Grid required at or beyond the Point of Interconnection to accommodate the interconnection of the Large Generating Facility to the ISO Controlled Grid. Network Upgrades shall consist of Delivery Network Upgrades and Reliability Network Upgrades.

New High Voltage Facility	A High Voltage Transmission Facility of a Participating TO that is placed in service after the beginning of the transition period described in Section 4 of Schedule 3 of Appendix F, or a capital addition made and placed in service after the beginning of the transition period described in Section 4.2 of Schedule 3 of Appendix F to an Existing High Voltage Facility.
New Participating TO	A Participating TO that is not an Original Participating TO.
Nomogram	A set of operating or scheduling rules which are used to ensure that simultaneous operating limits are respected, in order to meet NERC and WECC operating criteria.
Non-Generation Solutions	Solutions proposed by a PTO or an RA Entity that satisfy LARN which serve as an alternative to generation capacity, including equipment upgrades, operating procedures such as switching, manual Load shedding or automatic Load shedding, and other operational strategies or tools.
Non-Participating Generator	A Generator that is not a Participating Generator.
Non-Participating TO	A TO that is not a party to the TCA or for the purposes of Sections 16.1 and 16.2 of the ISO Tariff the holder of transmission service rights under an Existing Contract that is not a Participating TO.
Non-Spinning Reserve	The portion of off-line generating capacity that is capable of being synchronized and Ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least two hours.
NRC	The Nuclear Regulatory Commission or its successor.
NRC (Standards)	The reliability standards published by the NRC from time to time.
Operating Procedures	Procedures governing the operation of the ISO Controlled Grid as the ISO may from time to time develop, and/or procedures that Participating TOs currently employ which the ISO adopts for use.
Operating Reserve	The combination of Spinning and Non-Spinning Reserve required to meet WECC and NERC requirements for reliable

	Service Territory may be comprised of the Service Areas of more than one Local Public Owned Electric Utility, if they are operating under an agreement with the ISO for aggregation of their MSS and their MSS Operator is designated as the Participating TO.
Queue Position	The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the ISO.
Qualifying Capacity	The maximum capacity of a Resource Adequacy Resource. The criteria for calculating Qualifying Capacity from Resource Adequacy Resources may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO, or default provisions in Section 40.13 of this ISO Tariff.
Qualifying Facility	A qualifying co-generation or small power production facility recognized by FERC.
RA Entity	Any entity identified in Section 40.1 of the ISO Tariff.
RA Entity Load Share Percentage	An RA Entity's proportionate share of LARN in a TAC Area as determined in accordance with 43.2.1.1.
Ramping	Changing the loading level of a Generating Unit in a constant manner over a fixed time (e.g., ramping up or ramping down). Such changes may be directed by a computer or manual control.
RAS (Remedial Action Schemes)	Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS programming, that may be required.
RCST	The Reliability Capacity Services Tariff, as set forth in Section 43 of this ISO Tariff.
RCST Capacity Payment	The payment provided pursuant to Section 43.7.1 of the ISO Tariff.

Reactive Power Control	Generation or other equipment needed to maintain acceptable voltage levels on the ISO Controlled Grid and to meet reactive capacity requirements at points of interconnection on the ISO Controlled Grid.
Real Time Market	The competitive generation market controlled and coordinated by the ISO for arranging real-time Imbalance Energy.
Redispatch	The readjustment of scheduled Generation or Demand side management measures, to relieve Congestion or manage Energy imbalances.
Registered Data	Those items of technical data and operating characteristics relating to Generation, transmission or distribution facilities which are identified to the owners of such facilities as being information, supplied in accordance with the ISO Tariff, to assist the ISO to maintain reliability of the ISO Controlled Grid and to

	are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided under an RMR Contract (Section 30.6.1.2), local out-of-market dispatch calls (Section 11.2.4.2.1) and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section 40.8.6)
REMnet	The Wide Area Network through which the ISO acquires Meter Data.
Replacement Reserve	Generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and Ramping to a specified operating level within a sixty (60) minute period, the output of which can be continuously maintained for a two hour period. Also, Curtailable Demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours.
Residual LARN	The difference in MWs between the sum of the LARN Credits for a Local Reliability Area and the identified LARN for that Local Reliability Area, taking into account all RMR resources, Resource Adequacy Resources and resources identified in LARN Demonstrations that will be made available to the ISO in 2006, whether or not any of these resources are located in the Local Reliability Area.
Resource Adequacy	The program that ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability.
Resource Adequacy Capacity	The capacity of a Resource Adequacy Resource listed on a Resource Adequacy Plan and a Supply Plan.
Resource Adequacy Plan	A submission by a Scheduling Coordinator for a Load Serving Entity serving Load in the ISO Control Area in order to satisfy the requirements of Section 40 of this ISO Tariff.

Resource Adequacy Resource	A resource that is required to offer Resource Adequacy Capacity. The criteria for determining the types of resources that are eligible to provide Qualifying Capacity may be established by the CPUC, other applicable Local Regulatory Authority and provided to the ISO, or the default provision in Section 40.13 of this ISO Tariff.
Resource-Specific Settlement Interval Ex Post Price	The Resource-Specific Settlement Interval Ex Post Price will equal the Energy-weighted average of the applicable Dispatch Interval Ex Post Prices for each Settlement Interval taking into account each resource's Instructed Imbalance Energy, except Regulation Energy. The Resource-Specific Settlement Interval Ex Post Price shall apply to those resources that are capable of responding to ISO Dispatch Instructions.
Responsible Utility	The utility which is a party to the TCA in whose PTO Service Territory the Reliability Must-Run Unit is located or whose PTO Service Territory is contiguous to the PTO Service Territory in which a Reliability Must-Run Unit owned by an entity outside of the ISO Controlled Grid is located.
Revenue Requirement	The revenue level required by a utility to cover expenses made on an investment, while earning a specified rate of return on the investment.
Revised Adjusted RMR Invoice	The monthly invoice issued by the RMR Owner to the ISO pursuant to the RMR Contract reflecting any appropriate revisions to the Adjusted RMR Invoice based on the ISO's validation and actual data for the billing month.

reasonable uneconomic portion of costs associated with Generation-related assets and obligations, nuclear decommissioning, and capitalized Energy efficiency investment programs approved prior to August 15, 1996 and as defined in the California Assembly Bill No. 1890 approved by the Governor on September 23, 1996.

Short Start	Generating Units that that have a cycle time less than five hours (Start-Up Time plus Minimum Run Time is less than five hours) have a Start Up Time less than two hours, and that can be fully optimized with respect to this cycle time.
Significant Event	For 2006, a "Significant Event" is an event that results in a material difference in ISO Controlled Grid operations relative to what was assumed in developing the LARN Report for 2006 that causes, or threatens to cause, a failure to meet Applicable Reliability Criteria. For 2007, a "Significant Event" is an event that results in a material difference in ISO Controlled Grid operations relative to what was assumed by the CPUC and Local Regulatory Authorities in developing Local Resource Adequacy Requirements for 2007 that causes, or threatens to cause, a failure to meet Applicable Reliability Criteria.
Site Control	Documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.
Scheduling and Logging system for the ISO of California (SLIC)	A logging application that allows Market Participants to notify the ISO when a unit's properties change due to physical problems. Users can modify the maximum and minimum output of a unit, as well as the ramping capability of the unit.
Small Generating Facility	A Generating Facility that has a Generating Facility Capacity of no more than 20 MW.
Spinning Reserve	The portion of unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and that is capable of running for at least two hours.

Stand Alone Network Upgrades	Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the ISO Controlled Grid or Affected Systems during their construction. The Participating TO, the ISO, and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.
Standard Large Generator Interconnection Agreement (LGIA)	The form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility.
Standard Large Generator Interconnection	The ISO Protocol that sets forth the interconnection procedures applicable to an Interconnection Request pertaining to a Large

	site test operations and commissioning of a Generating Unit prior to Commercial Operation.
Trustee	The trustee of the California Independent System Operator trust established by order of the California Public Utilities Commission on August 2, 1996 Decision No. 96-08-038 relating to the Ex Parte Interim Approval of a Loan Guarantee and Trust Mechanism to Fund the Development of an Independent System Operator (ISO) and a Power Exchange (PX) pursuant to Decision 95-12-063 as modified.
2007 Local Reliability Area	An area for which the CPUC or applicable Local Regulatory Authority has established a Local Resource Adequacy Requirement for 2007 for RA Entities subject to their jurisdiction.
UDC (Utility Distribution Company)	An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and that provides regulated retail electric service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer.
UDP Aggregation	Two or more units scheduled by the same Scheduling Coordinator with the same resource identification that are to be considered interchangeable for calculating the UDP.
Unaccounted for Energy (UFE)	UFE is the difference in Energy, for each utility Service Area and Settlement Period, between the net Energy delivered into the utility Service Area, adjusted for utility Service Area Transmission Losses (calculated in accordance with Section 27.2.1.2), and the total metered Demand within the utility Service Area adjusted for distribution losses using Distribution System loss factors approved by the Local Regulatory Authority. This difference is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical Load profile errors, and distribution loss deviations.
Uncontrollable Force	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.

Uninstructed Deviation	A deviation from the resources' Dispatch Operating Point.
Uninstructed Deviation Penalty	The penalty as set forth in Section 11.2.4.1.2 of this ISO Tariff.
Uninstructed Imbalance	The real-time change in Generation or Demand other than that

Agreement	Agreement dated June 18, 1999 among the WSCC and certain of its Member transmission operators, as such may be amended from time to time.
Year-Ahead System Resource Adequacy Requirements	The amount of Qualifying Capacity that a RA Entity must reflect in its year-ahead Resource Adequacy Plan submitted pursuant to Section 40.2.1 in compliance with Resource Adequacy Rules adopted by the CPUC or a Local Regulatory Authority, as applicable.
Year-Ahead System Resource Deficiency	The monthly deficiency in meeting Year-Ahead System Resource Adequacy Requirements as determined by the CPUC and applicable Local Regulatory Authorities.
Zone	A portion of the ISO Controlled Grid within which Congestion is expected to be small in magnitude or to occur infrequently. "Zonal" shall be construed accordingly.
Zonal Settlement Interval Ex Post Price	The Zonal Settlement Interval Ex Post Price in a Settlement Interval 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.

ISO TARIFF APPENDIX F
Schedule 6

RCST SCHEDULES

Monthly RCST Charge

The Monthly RCST Charge shall be calculated by multiplying the monthly shaping factors by the target annual capacity price ($73/kW-yr).

Monthly Shaping Factors

	SP-15	NP-15/ZP-26
Jan	6.7%	4.9%
Feb	5%	4.9%
Mar	5%	5.6%
Apr	5.8%	4.6%
May	6.3%	4.8%
Jun	8.3%	5.1%
Jul	15.8%	13.7%
Aug	17.5%	15.3%
Sept	11.7%	13.8%
Oct	5.8%	8.7%
Nov	6.3%	8.8%
Dec	5.8%	9.8%
Total	100%	100%

Availability

The target Availability for a resource designated under RCST is 95%. Incentives and penalties for availability above and below the target are as set forth in the table below, entitled "Availability Factor Table." The ISO will calculate availability on a monthly basis using actual availability data. The "Availability Factor" for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability (excluding only Scheduled Maintenance)	**Capacity Payment Factor**	**Availability Factor**
100%	3.3%	1.139
99%	3.3%	1.106
98%	3.3%	1.073
97%	2.5%	1.040
96%	1.5%	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*	.908-.755
79-41%	-1.9%*	.736-.014
-40%	-	0.0

*The "Capacity Payment Factor" decreases by 1.7% and 1.9% respectively for every 1% decrease in availability.

The capacity payment will be adjusted upward from the 95% Availability starting point by the positive percentages listed as the Capacity Payment Factor above, by the amounts listed for each availability factor above 95%, so that, for example, if a 97% Availability is achieved for the month (as described below), then the capacity payment for that month would be the monthly value for 95% plus an additional 4% (1.5% for the first percent Availability above 95%, and 2.5% for the second percent Availability above 95%). Reductions in capacity payment will be made correspondingly according to the Capacity Payment Factor above for monthly availability levels falling short of the 95% availability starting point.

Calculation of the Monthly PER

The ISO shall calculate the Monthly Peak Energy Rent ("Monthly PER") as follows: immediately following the end of the month the ISO will determine all those hours during which the Reference Resource would have been dispatched (based on Reference Resource characteristics) to provide either energy or non-spinning reserves and will calculate, on a per kW-Month basis, the total dollar amount of rent (earnings in excess of proxy unit variable costs calculated using Reference Resource unit characteristics) that would have been earned by the Reference Resource. The Reference Resource will be assumed to have been dispatched for energy in any hour in which the hourly energy price described below is greater than the Reference Resource variable cost; the ISO shall use its day ahead Non-spinning Reserve price to calculate the rent for all hours in which the Reference Resource is not assumed dispatched to provide energy (i.e., any hour where the hourly price is less than the Reference Resource variable costs). .

Hourly price profiles will be determined using the shaping factors for SP-15 and NP15/ZP-26 that appear below. Hourly energy prices shall be the weighted average of: (1) the applicable zonal on/off peak day-ahead index prices set forth in Platts Megawatt Daily, shaped to hourly profiles using the factors set forth below, and (2) the applicable zonal ISO hourly average real-time energy prices. For 2006, the index/ex post weighting will be 50/50, respectively. For 2007, the index/ex post weighting will be 75/25, respectively.

The assumed heat rate of the Reference Resource will be 10,500 BTU/kWh. Variable operations and maintenance costs shall be based on the Energy Information Administration AEO Electricity Market Module Assumptions, which are currently $3.16/MWh. An emissions allowance of $0.71/MWh shall be used to estimate variable costs. Gas prices for the Reference Resource will be based on a daily gas price based on 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 is served from one of those three Service Areas then from the nearest of those Service Areas.

NP-15

	Mon-Fri JAN-MAY	Mon-Fri JUN-SEPT	Mon-Fri OCT-DEC	Sat JAN-MAY	Sat JUN-SEPT	Sat OCT-DEC	Sun JAN-MAY	Sun JUN-SEPT	Sun OCT-DEC
N1	1.05454758	1.00584021	0.99435526	1.43649	1.120844	1.073148	0.755403	0.759704	0.783346
N2	0.85716711	0.86062114	0.91898795	1.032749	1.092377	0.978957	0.600188	0.683139	0.701588
N3	0.75399836	0.79068297	0.92144851	0.758585	0.91744	0.921009	0.458319	0.636187	0.68291
N4	0.71058351	0.79900018	0.89479611	0.680278	0.892744	0.911836	0.444573	0.616409	0.662295
N5	0.78267681	0.8161591	0.94516384	0.630256	0.909543	0.926083	0.362844	0.5641	0.662342
N6	1.02256586	0.86829359	1.10962719	0.623168	0.709153	0.947344	0.293086	0.335463	0.707489
N7	0.75351629	0.46629678	0.84979936	0.459933	0.363102	0.835985	0.324748	0.244038	0.795325
N8	0.88610975	0.66277777	0.86218587	0.741872	0.587123	0.805198	0.576432	0.514076	0.804009
N9	0.93647065	0.72748598	0.87228518	0.967023	0.960062	0.891018	0.923411	0.756354	0.873764
N10	0.98013307	0.83355915	0.99306313	1.050452	0.998448	0.917894	1.087891	0.848836	0.970588
N11	1.05081328	0.91348904	0.97923559	1.079888	0.984474	1.02248	1.303241	0.94756	1.027355
N12	1.068781	0.96178966	0.98802244	1.086984	1.03194	0.961419	1.304385	1.158765	1.097895
N13	1.06644102	1.07695356	0.99576872	1.083005	1.00669	0.992817	1.283414	1.168292	1.059999
N14	1.09775977	1.22226563	1.06440722	1.072448	1.0038	1.04347	1.281892	1.283789	1.110655
N15	1.09364901	1.38229366	1.11766171	1.053707	1.124805	1.05608	1.263359	1.309879	1.150637
N16	1.0841716	1.44680734	1.14665908	1.048562	1.135933	1.056274	1.316946	1.317595	1.140864
N17	1.02358917	1.3710053	1.1033917	1.049893	1.362503	1.087482	1.311524	1.567664	1.232842
N18	0.9788975	1.21057642	0.95748393	1.049616	1.327635	1.081109	1.30229	1.71578	1.406331
N19	0.94570613	1.03868542	1.10717179	1.036387	1.126072	1.09328	1.321985	1.367096	1.419466
N20	0.96174495	0.91022871	1.13578926	1.048527	0.943973	1.193558	1.393578	1.139089	1.494944
N21	1.11577915	0.94038191	1.03355639	1.133815	1.001619	1.076201	1.778309	1.551657	1.39373
N22	0.95643767	0.8354037	0.79351865	1.037886	1.04182	0.885733	1.392837	1.473652	1.062792
N23	1.56132501	1.66415743	1.17445625	1.670367	1.287221	1.205472	1.150247	1.253671	0.972486
N24	1.25713576	1.19524538	1.04116487	1.168106	1.070678	1.036151	0.769097	0.787205	0.786348

SP-15

Weekday January through June

Hour	January	February	March	April	May	June
1	0.9	0.97	1.018	0.973	0.951	0.945
2	0.858	0.906	0.896	0.902	0.839	0.826
3	0.839	0.885	0.828	0.849	0.756	0.745
4	0.836	0.876	0.821	0.824	0.717	0.727
5	0.887	0.977	0.948	0.878	0.879	0.794
6	1.155	1.11	1.068	1.008	1.086	0.908
7	0.898	0.933	0.79	0.779	0.6	0.474
8	1.007	1	0.892	0.92	0.778	0.613
9	1.017	1.004	0.941	0.94	0.875	0.711
10	1.011	1.019	0.983	0.991	0.976	0.806
11	0.976	0.994	1.027	1.024	1.035	1.04
12	0.98	0.99	1.038	1.038	1.074	1.087
13	0.972	0.994	1.055	1.075	1.126	1.127
14	0.983	0.984	1.06	1.098	1.193	1.201
15	0.955	0.963	1.039	1.072	1.175	1.247
16	0.896	0.932	0.994	1.031	1.147	1.26
17	0.899	0.905	0.956	0.965	1.089	1.216
18	1.171	1.044	0.983	0.914	0.997	1.12
19	1.158	1.136	1.167	0.944	0.882	1.012
20	1.075	1.067	1.082	1.06	0.965	0.965
21	1.059	1.06	1.048	1.14	1.153	1.119
22	0.941	0.975	0.946	1.009	0.935	0.999
23	1.371	1.213	1.305	1.383	1.536	1.733
24	1.153	1.062	1.117	1.183	1.235	1.322

Saturday January through June

Hour	January	February	March	April	May	June
1	0.999	1.073	1.104	0.982	1.071	1.064
2	0.905	0.971	0.922	0.917	0.957	0.882
3	0.899	0.962	0.889	0.883	0.839	0.828
4	0.875	0.93	0.868	0.855	0.814	0.803
5	0.91	0.917	0.88	0.904	0.826	0.788
6	0.972	0.993	0.88	0.969	0.836	0.818
7	0.795	0.854	0.777	0.761	0.603	0.411
8	0.874	0.906	0.844	0.848	0.728	0.522
9	0.992	1.015	0.932	0.929	0.885	0.645
10	1.028	1.037	0.997	0.999	0.984	0.806
11	1.005	1.048	1.027	1.042	1.047	1.055
12	1.005	1.033	1.027	1.053	1.069	1.089
13	0.978	1.009	1.032	1.054	1.096	1.122
14	0.939	0.967	0.983	1.042	1.093	1.165
15	0.882	0.939	0.963	1.022	1.086	1.203
16	0.871	0.892	0.949	0.973	1.071	1.255
17	0.945	0.899	0.934	0.962	1.063	1.254
18	1.196	1.03	1.016	0.912	1.011	1.17
19	1.195	1.155	1.199	1.047	0.934	1.075
20	1.141	1.076	1.165	1.113	1.058	0.984
21	1.114	1.104	1.133	1.165	1.237	1.143
22	1.04	1.036	1.022	1.076	1.035	1.102
23	1.323	1.117	1.331	1.327	1.478	1.622
24	1.117	1.038	1.126	1.164	1.18	1.194

Sunday January through June

Hour	January	February	March	April	May	June
1	0.897	0.85	0.787	0.869	0.794	0.854
2	0.806	0.792	0.762	0.771	0.7	0.7
3	0.745	0.802	0.716	0.732	0.628	0.622
4	0.706	0.802	0.695	0.722	0.594	0.519
5	0.707	0.794	0.707	0.696	0.623	0.469
6	0.782	0.793	0.72	0.671	0.585	0.445
7	0.818	0.873	0.691	0.711	0.471	0.372
8	0.882	0.912	0.819	0.826	0.635	0.522
9	0.975	1.007	0.945	0.926	0.757	0.631
10	1.035	1.073	1.029	1.002	0.87	0.75
11	1.03	1.065	1.069	1.059	1.059	1.019
12	1.049	1.063	1.112	1.101	1.126	1.141
13	1.043	1.065	1.147	1.118	1.176	1.268
14	1.029	1.061	1.141	1.127	1.239	1.341
15	1.003	1.033	1.11	1.097	1.279	1.44
16	0.98	1.004	1.115	1.11	1.295	1.482
17	1.039	1.006	1.091	1.052	1.336	1.528
18	1.324	1.161	1.179	1.033	1.363	1.403
19	1.37	1.305	1.421	1.191	1.231	1.321
20	1.338	1.248	1.366	1.35	1.327	1.242
21	1.286	1.213	1.288	1.469	1.471	1.381
22	1.166	1.144	1.191	1.318	1.263	1.291
23	1.079	1.066	1.082	1.127	1.239	1.339
24	0.912	0.869	0.816	0.922	0.938	0.92

Weekday July through December

Hour	July	August	Septemb er	October	Novembe r	Decembe r
1	1.002	0.994	1.083	1.04	0.966	1.001
2	0.89	0.903	0.92	0.879	0.834	0.883
3	0.81	0.835	0.782	0.751	0.706	0.814
4	0.767	0.813	0.749	0.69	0.723	0.805
5	0.796	0.841	0.822	0.829	0.879	0.903
6	0.914	0.982	1.049	1.08	1.266	1.088
7	0.493	0.547	0.634	0.763	0.899	0.895
8	0.632	0.637	0.751	0.858	0.98	1.012
9	0.728	0.743	0.786	0.837	0.977	1.012
10	0.837	0.822	0.859	0.9	0.957	1.005
11	0.983	0.999	0.966	0.96	0.959	0.983
12	1.051	1.056	1.013	0.975	0.943	0.93
13	1.097	1.106	1.078	1.013	0.933	0.906
14	1.183	1.179	1.15	1.076	0.946	0.894
15	1.257	1.24	1.213	1.147	0.93	0.87
16	1.284	1.264	1.236	1.152	0.93	0.863
17	1.255	1.235	1.197	1.129	0.999	0.967
18	1.183	1.149	1.11	1.019	1.221	1.194
19	1.065	1.05	1.052	1.073	1.207	1.213
20	0.982	1.05	1.051	1.122	1.137	1.174
21	1.034	1.028	1.031	1.048	1.046	1.085
22	0.935	0.895	0.876	0.927	0.936	0.998
23	1.623	1.493	1.371	1.497	1.427	1.316
24	1.197	1.14	1.223	1.235	1.2	1.191

Saturday July through December

Hour	July	August	September	October	November	December
1	1.065	1.107	1.206	1.202	1.145	1.108
2	0.952	0.984	1.046	1.038	0.952	0.982
3	0.88	0.939	0.919	0.871	0.784	0.86
4	0.85	0.847	0.844	0.766	0.753	0.843
5	0.871	0.832	0.863	0.778	0.821	0.875
6	0.841	0.862	0.848	0.885	1.014	0.909
7	0.451	0.494	0.542	0.609	0.745	0.76
8	0.539	0.56	0.622	0.63	0.893	0.845
9	0.682	0.679	0.733	0.663	0.961	0.997
10	0.778	0.788	0.814	0.943	0.977	1.015
11	0.956	0.918	0.971	1.017	1.027	1.022
12	1.019	1.029	1.045	1.039	1.002	1
13	1.087	1.103	1.125	1.068	0.924	0.984
14	1.16	1.183	1.149	1.108	0.91	0.921
15	1.236	1.252	1.194	1.105	0.889	0.818
16	1.284	1.298	1.216	1.124	0.89	0.775
17	1.301	1.252	1.205	1.073	1.003	1.005
18	1.251	1.215	1.17	1.103	1.237	1.212
19	1.132	1.097	1.086	1.157	1.228	1.211
20	1.029	1.111	1.097	1.208	1.172	1.173
21	1.076	1.077	1.074	1.176	1.1	1.139
22	1.02	0.943	0.957	0.976	1.041	1.124
23	1.395	1.358	1.185	1.389	1.41	1.291
24	1.147	1.07	1.09	1.071	1.12	1.133

Sunday July through December

Hour	July	August	September	October	November	December
1	0.834	0.81	0.884	0.868	0.916	0.889
2	0.739	0.729	0.688	0.685	0.788	0.809
3	0.679	0.672	0.527	0.562	0.613	0.698
4	0.655	0.653	0.489	0.574	0.676	0.634
5	0.61	0.657	0.463	0.558	0.586	0.68
6	0.496	0.647	0.512	0.613	0.62	0.747
7	0.445	0.549	0.527	0.573	0.666	0.777
8	0.587	0.618	0.619	0.697	0.776	0.848
9	0.719	0.704	0.713	0.708	0.997	0.985
10	0.877	0.854	0.901	0.829	1.103	1.052
11	1.005	0.991	1.035	1.102	1.143	1.067
12	1.106	1.154	1.178	1.163	1.151	1.052
13	1.167	1.151	1.318	1.154	1.125	1.029
14	1.264	1.25	1.353	1.24	1.138	0.993
15	1.339	1.358	1.347	1.252	1.085	0.929
16	1.432	1.43	1.354	1.272	1.063	0.92
17	1.447	1.467	1.375	1.235	1.279	1.146
18	1.383	1.396	1.372	1.407	1.346	1.351
19	1.301	1.278	1.314	1.481	1.395	1.387
20	1.194	1.243	1.336	1.517	1.296	1.317
21	1.336	1.322	1.359	1.477	1.217	1.279
22	1.217	1.171	1.24	1.18	1.097	1.241
23	1.221	1.053	1.171	1.115	1.096	1.188
24	0.956	0.843	0.923	0.735	0.927	0.983

2.4.4 The ISO shall monitor ISO Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices in an ISO Market or other payments. The ISO shall: (i) seek to amend the foregoing list as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the ISO Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the FERC as may be appropriate.

3 CRITERIA FOR IMPOSING MITIGATION MEASURES

3.1 Identification of Conduct Inconsistent with Competition

Conduct that may potentially warrant the imposition of a mitigation measure includes the categories described in Section 2.4 above. The thresholds listed in Section 3.1.1 below shall be used to identify substantial departures from competitive conduct indicative of an absence of workable competition.

3.1.1 Conduct Thresholds for Identifying Economic Withholding

The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of the bid from a resource and shall be determined with respect to a reference level determined as specified in Section 3.1.1.1:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of a 200 percent increase or $100/MWh increase in the bid with respect to its Reference Level.

3.1.1.1 Reference Levels

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

1. the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (Pmin) and maximum (Pmax) operating point.

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

   1. Excluding proxy and mitigated bids, the accepted bid, or the lower of the mean or the median of a resource's accepted bids if such a resource has more than one accepted 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. Accepted and justified bids above the applicable soft cap, as set forth in Section 39.2 of this Tariff, will be included in the calculation of reference prices.

2. If the resource is a gas-fired unit that does not have significant energy limitations, the unit's default Energy Bid determined monthly as set forth in Section 5.11.5 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh).

4 MITIGATION MEASURES

4.1 Purpose

If conduct is detected that meets the criteria specified in Section 3, the appropriate mitigation measures described in this Section 4 shall be applied by the ISO. The conduct specified in Section 3.1.1 shall be remedied by the prospective application of a default bid measure as described in Section 4.2 for the specific hour that they violate the price and market impact thresholds.

4.2 Sanctions for Economic Withholding

4.2.1 Default Bid

A default bid shall be designed to cause a Market Participant to bid as if it faced workable competition during a period when: (i) the Market Participant does not face workable competition and (ii) has responded to such condition by engaging in the economic withholding of an Electric Facility. In designing and implementing default bids, the ISO shall seek to avoid causing an Electric Facility to bid below its marginal cost.

4.2.2 Implementation

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

(b) The Mitigation Measures will be applied to 1) all incremental bids submitted to the real-time Imbalance Energy market during the pre-dispatch process prior to the real-time Imbalance Energy market based on the projected real-time MCPs that are computed during this process; and 2) to the Day-Ahead and the Hour-Ahead Energy markets when these markets are made operational.

(c) An Electric Facility subject to a default bid shall be paid the MCP applicable to the output from the facility. Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the MCP applicable to that facility.

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

(e) The Mitigation Measures shall not be applied to Energy Bids projected to be Dispatched as Imbalance Energy through the RTD Software in the hours in which all Zonal Ex Post Prices are projected to be below $200/MWh. If the Zonal Dispatch Interval Ex Post Price is projected to be above $200/MWh in any ISO Zone, the Mitigation Measures shall be applied to all bids, except those from System Resources, in all ISO Zones. The ISO will apply Mitigation Measures to all bids taken out of merit order to address Intra-Zonal Congestion.

(f) The Mitigation Measures shall not be applied to bids below $25/MWh.

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

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

Attachment A(2)

Blackline Tariff Sheets

RCST Changes Made to Conformed S&R Tariff Dated March 22, 2006

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8.5 The Bidding Process.

8.5.4 Bid Evaluation Rules.

Bid evaluation shall be based on the following principles:

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

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

(c) for the Day-Ahead Market, the Day-Ahead bids shall be evaluated independently for each of the 24 Settlement Periods of the following Trading Day;

(d) for the Hour-Ahead Market, the ISO shall evaluate bids in the two hours preceding the hour of operation;

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

(f) the ISO will (to the extent available) procure sufficient Ancillary Services to meet its requirements;~~ and~~

(g) the ISO will evaluate and price only those Ancillary Services bids received; and~~.~~

(h) Until the earlier of the midnight of day before the effective date of the MRTU Tariff or midnight on December 31, 2007, the ISO will not consider in the Ancillary Service bid evaluation process the Ancillary Services bids of Condition 2 RMR resources that are Condition 2 prior to

March 31, 2006. This Section 8.5.4(h) shall expire at midnight on the earlier of December 31, 2007 or the date immediately before the MRTU goes into effect.

Sections Added in the Conformed S&R Tariff Dated March 22, 2006

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34 REAL-TIME.

34.1.2 Energy Bid Submission.

34.1.2.1 Real Time Market

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.

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RCST Changes Made to the RA Tariff Amendment (ER06-723-000) Filing

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40.6A Availability of Resource Adequacy Resources.

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.

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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.

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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 <u>or resources designated as RCST</u> 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 <u>and RCST resources</u> 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.

New RCST Sections To Be Added at End of Section 40 of the RA Tariff Amendment (ER06-723-000) Filing

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<u>40.14 Capacity Payments Under the FERC Must Offer Obligation.</u>

<u>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 43.9 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.</u>

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).

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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 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 of 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. If Non-Generation Solutions were adopted by the ISO to reduce LARN pursuant to Section 43.2.1.1 above, the ISO shall also explain why the Non-Generation Solution was 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.

New Section To Be Added After Section 42 of the RA Tariff Amendment (ER06-723-000) Filing

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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. ER06-146 (changes to Sections 8.5.4; 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 2006 Local RCST Designations

43.2.1.1 Determination of Responsibility for Local Area Reliability Needs

The ISO shall determine the RA Entity Load Share Percentage for each RA Entity. The RA Entity Load Share Percentage shall be calculated for each RA Entity by dividing the RA Entity's actual annual coincident peak Load in each TAC Area in 2005 ("RA Entity Load Share") by the total coincident peak Load of all RA Entities in the TAC Area in 2005 ("Total TAC Load"). The ISO will calculate a RA Entity's LARN Allocation in a TAC Area by multiplying, for each TAC Area, the RA Entity Load Share Percentage by the LARN in the TAC Area.

43.2.1.2 LARN Demonstrations and Crediting

The ISO will provide a Scheduling Coordinator for a RA Entity ("SC-RA Entity") with a LARN Credit for each MW of capacity in a RA Entity's LARN Demonstration that meets the following requirements: (1) the capacity is provided to the ISO under the same terms and conditions as Resource Adequacy Resources under Section 40.6A, and (2) the capacity either (a) qualifies as a Local Area Resource, or is (b) Qualifying Capacity for a Generating Unit or Participating Load that is a Resource Adequacy Resource identified in a RA Entity's Resource Adequacy Plan and which is located in a Local Reliability Area.

The ISO will provide a LARN Credit to account for RMR megawatts paid by an RA Entity as set forth below. PTOs will provide the ISO with the necessary information to enable the ISO to calculate the proportion of RMR megawatts paid for by the RA Entity ("RA Entity RMR MW Number") as follows: (i) for RMR Units that have fixed costs paid through either Annual Fixed Reliability Costs ("AFRC"), or Annual Fixed Revenue Requirement ("AFRR") multiplied by a Fixed Option Payment Factor ("FOPF") -- as defined in applicable RMR agreements -- by applying the RA Entity's percentage of responsibility for such costs as assessed through PTO FERC tariffs, or (ii) for RMR Units that have the full functional equivalent of AFRC or AFRR multiplied by FOPF paid by an RA Entity through a Resource Adequacy Resource contract that requires AFRC or AFRR multiplied by FOPF be set to zero, by applying 100% to the RA Entity paying such costs through the contract. To the extent PTOs do not provide the ISO with the information necessary to calculate the RA Entity RMR MW Number, as described above, the ISO shall calculate the RA Entity RMR MW Number based on RA Entity Load Share Percentage.

The ISO will also provide a SC-RA Entity with a LARN Credit for each MW of Participating Load and Distributed Generation that is dispatchable by the ISO that are in an RA Entity's LARN Demonstration and which are located in a Local Reliability Area. For purposes of this section, Distributed Generation is the capacity of generating units that are connected to the distribution facilities of load serving entities.

43.2.1.3 Determination of LARN Credits

Following the ISO's review of any LARN Demonstrations that a SC-RA Entity submits to the ISO in accordance with the criteria set forth in Section 43.2.1.2, the ISO will inform each SC-RA Entity of the amount of LARN Credit that it will receive against its LARN Allocation.

43.2.1.4 Residual LARN Determination Report

By May 24, 2006, the ISO will issue a report detailing: (1) the ISO's evaluation of the LARN Demonstrations of all RA Entities, including a determination of the Effectiveness of all resources in the LARN Demonstrations; (2) if relevant, the reasons that the aggregate LARN Demonstrations of all RA Entities, combined with RMR Units and Resource Adequacy Resources, have not satisfied the LARN in any Local Reliability Area, and (3) the amount of any Residual LARN in any Local Reliability Area.

43.2.1.5 RCST Designation for Residual LARN

No sooner than May 24, 2006, the ISO may designate Eligible Capacity that qualifies as a Local Area Resource to provide services under the RCST to the extent necessary to cover the Residual LARN amount, consistent with the criteria specified in Section 43.2.3. RCST designations under this Section shall be for a term that commences no sooner than June 1, 2006, and terminates at midnight on December 31, 2006.

43.2.2 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. 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 the 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. Following both the CAISO's identification of any Local Resource Adequacy Requirement Deficiency and any CPUC or Local Regulatory Authority-established opportunity to correct such deficiency, the ISO may designate Eligible Capacity to provide services under the RCST consistent with the criteria set forth in Section 43.2.3, taking into account all RMR and Resource Adequacy Resources that will be made available to the ISO in 2007, whether or not any of those resources are located in the 2007 Local Reliability Area. The ISO may designate Eligible Capacity to provide service under this Section 43.2.2 to the extent necessary to cover 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. 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 MRTU Tariff.

43.2.3 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 TAC Area or 2007 Local Reliability Area, whichever is applicable, 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 2006, any designation of Eligible Capacity pursuant to Section 43.2.1.5 for 2006 or, for 2007, any designation of Eligible Capacity pursuant to Section 43.2.2, 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 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 of 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 shall also, to the extent that they have any available capacity not designated under RCST or under contract as a Resource Adequacy Requirements resource, offer such capacity into the next available Ancillary service markets.

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 as well as 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 2006: If the ISO makes local designation under RCST for 2006 under Section 43.2.1, then the ISO will allocate the total costs of RCST Capacity Payments for such designations as follows:

a. The ISO will determine a Gross LARN Allocation amount for each SC-RA Entity by multiplying the Scheduling Coordinator's RA Entity's Load Share Percentage in the TAC Area by the sum of (a) all LARN Credits in the TAC

Area for all SC-RA Entities and (b) the total megawatts of RCST designations in the TAC Area made pursuant to Section 43.2.1.

b. The ISO will determine a Net LARN Allocation amount for each SC-RA Entity by subtracting the LARN Credits for that SC-RA Entity from its Gross LARN Allocation amount determined in accordance with Section 43.8(3)(a). If a SC-RA Entity's LARN Credits are greater than its LARN Allocation amount as determined in accordance with Section 43.2.1.1, then the SC-RA Entity's Net LARN Allocation amount shall be zero.

c. The ISO will determine, for each TAC Area, the "2006 TAC Area Tier 1 Local RCST MW Total," which is the lesser of (1) the difference between the LARN in the TAC Area and the sum of all LARN Credits in the TAC Area for all SC-RA Entities (if zero or greater); (2) the sum of the RCST designations for 2006 under Section 43.2.1, in that TAC Area. The "2006 TAC Area Tier 2 Local RCST MW Total" for that TAC Area shall be the remainder (in megawatts) of the RCST designations for 2006 under Section 43.2.1, in that TAC Area, if any.

d. The ISO shall calculate "2006 Tier 1 Level RCST Costs" by multiplying the total RCST Capacity Payments to Generating Units in the TAC Area designated under Section 43.2.1, by the percentage that the 2006 TAC Area Tier 1 RCST MW Total represents of the total MW quantity of RCST designations for 2006 under Section 43.2.1 in that TAC Area. The remaining costs for RCST Capacity Payments to Generating Units in the TAC Area shall be "2006 TAC Area Tier 2 RCST Costs."

e. The ISO will allocate the 2006 Tier 1 Local RCST Costs for each TAC Area to SC-RA Entities in that TAC Area in proportion to the ratio of each SC-RA Entity's Net LARN Allocation to the total Net LARN Allocation for all SC-RA

Entities for that TAC Area as determined in accordance with Section 43.8(3)(b).

f. The ISO will allocate the 2006 Tier 2 Local RCST Costs for each TAC Area to all SC-RA Entities in that TAC Area based on Scheduling Coordinator's RA Entity's Load Share Percentage(s) in the TAC Area.

(4) Local RCST Designations for 2007.

[Reserved]

(5) 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 Coordinator's RA Entity's Load Share Percentage(s) in such TAC Area(s).

(6) Significant Event Designations for 2007:

[Reserved]

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[From ISO Tariff Appendix A (Master Definitions Supplement)]

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<u>Contingencies of Concern</u>	<u>For 2006, contingencies evaluated by the ISO in the study that resulted in the LCR Report that caused the ISO to identify an area as a Local Reliability Area.</u>
<u>Effectiveness</u>	<u>The ability of a resource to address one or more Contingencies of Concern affecting a Local Reliability Area expressed as a percentage with respect to each relevant Contingency of Concern of the ability of the most effective resource to address that contingency.</u>
<u>Eligible Capacity</u>	<u>Capacity of Generating Units of Participating Generators located within the ISO Control Area except the following: capacity associated with hydroelectric generation, nuclear generation, QFs, generation resources within a Metered Subsystem, resources owned by the California Department of Water Resources, State Water Project; capacity of a Generating Unit with a Reliability Must-Run contract, during the term of such contract; capacity of a Resource Adequacy Resource that is identified in any Resource Adequacy Plan in accordance with Section 40, during the time that such capacity is identified on the Resource Adequacy Plan; and capacity that has been designated to provide serve under the RCST, during the term of the designation.</u>
<u>LARN Allocation</u>	<u>The ISO's allocation of responsibility, expressed in MW, to each RA Entity represented by a Scheduling Coordinator for the LARN in each TAC Area(s) within which the RA Entity serves Load.</u>

LARN Credit	The amount by which an RA Entity's LARN Allocation will be reduced in accordance with the criteria in Section 43.2.1.2.
LARN Demonstration	The demonstration made to the ISO by a Scheduling Coordinator for an RA Entity of the resources that the RA Entity will make available to the ISO to satisfy the LARN.
LARN Report for 2006	The report, published by the ISO, which identifies each Local Reliability Area, the contingencies that require the ISO to specify a geographically contiguous area as a Local Reliability Area, and the amount of generation (in MW) needed for each Local Reliability Area in order to satisfy Applicable Reliability Criteria, taking into account Non-Generation Solutions.
Local Area Reliability Needs (LARN)	As identified in the LARN Report for 2006, the amount of generation (in MW) needed for a Local Reliability Area in order to satisfy Applicable Reliability Criteria in 2006.
Local Area Resource	A Local Area Resource is a Generating Unit located in a Local Reliability Area that has a material degree of Effectiveness.
Local Reliability Area	For 2006, a geographically contiguous area within a TAC Area that the CAISO has determined, through reliability studies, requires Local Area Resources to meet Applicable Reliability Criteria.
Local Resource Adequacy Demonstration	The demonstration made to the ISO by the Scheduling Coordinator for a RA Entity of the resources that the RA Entity will make available to the ISO to satisfy Local Resource Adequacy Requirements.
Local Resource Adequacy Requirement Deficiency	The difference in MWs between the sum of Local Resource Adequacy Requirements for RA Entities in a given 2007 Local Reliability Area and the quantity of MWs shown in RA Entities' Local Resource Adequacy Demonstrations for that 2007 Local

	Reliability Area
Local Resource Adequacy Requirement	The Resource Adequacy Requirement established by the CPUC or a Local Regulatory Authority in a 2007 Local Reliability Area (or for 2007 Local Reliability Areas in the aggregate) for each RA Entity subject to their jurisdiction.
Monthly RCST Charge	The monthly charge determined in accordance with Appendix F, Schedule 6.
Month-Ahead System Resource Adequacy Requirements	The amount of Qualifying Capacity that a RA Entity must reflect in its monthly Resource Adequacy Plan submitted pursuant to Section 40.2.2 in compliance with Resource Adequacy Rules adopted by the CPUC or a Local Regulatory Authority, as applicable.
Month-Ahead System Resource Deficiency	The monthly deficiency in meeting the Month-Ahead System Resource Adequacy Requirements as determined by the CPUC and applicable Local Regulatory Authorities for each RA Entity subject to their jurisdiction.
MRTU Tariff	The ISO Tariff that will implement the ISO's Market Redesign and Technology Upgrade ("MRTU").
Must-Offer Capacity Payment	The payment made in accordance with Section 43.9 of this ISO Tariff.
Non-Generation Solutions	Solutions proposed by a PTO or an RA Entity that satisfy LARN which serve as an alternative to generation capacity, including equipment upgrades, operating procedures such as switching, manual Load shedding or automatic Load shedding, and other operational strategies or tools.
RA Entity	Any entity identified in Section 40.1 of the ISO Tariff.
RA Entity Load Share Percentage	An RA Entity's proportionate share of LARN in a TAC Area as determined in accordance with 43.2.1.1.

RCST	The Reliability Capacity Services Tariff, as set forth in Section 43 of this ISO Tariff.
RCST Capacity Payment	The payment provided pursuant to Section 43.7.1 of the ISO Tariff.
Residual LARN	The difference in MWs between the sum of the LARN Credits for a Local Reliability Area and the identified LARN for that Local Reliability Area, taking into account all RMR resources, Resource Adequacy Resources and resources identified in LARN Demonstrations that will be made available to the ISO in 2006, whether or not any of these resources are located in the Local Reliability Area.
Significant Event	For 2006, a "Significant Event" is an event that results in a material difference in ISO Controlled Grid operations relative to what was assumed in developing the LARN Report for 2006 that causes, or threatens to cause, a failure to meet Applicable Reliability Criteria. For 2007, a "Significant Event" is an event that results in a material difference in ISO Controlled Grid operations relative to what was assumed by the CPUC and Local Regulatory Authorities in developing Local Resource Adequacy Requirements for 2007 that causes, or threatens to cause, a failure to meet Applicable Reliability Criteria.
2007 Local Reliability Area	An area for which the CPUC or applicable Local Regulatory Authority has established a Local Resource Adequacy Requirement for 2007 for RA Entities subject to their jurisdiction.
Year-Ahead System Resource Adequacy Requirements	The amount of Qualifying Capacity that a RA Entity must reflect in its year-ahead Resource Adequacy Plan submitted pursuant to Section 40.2.1 in compliance with Resource Adequacy Rules adopted by the CPUC or a Local Regulatory Authority, as

applicable.

Year-Ahead System Resource Deficiency	The monthly deficiency in meeting Year-Ahead System Resource Adequacy Requirements as determined by the CPUC and applicable Local Regulatory Authorities.

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Schedule 6 To Be Added to Appendix F of the Conformed S&R Tariff Filed on March 22, 2006
[Note: Schedule 5 was added with Amendment 68 Station Power Compliance Filing ER05-849-000]

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ISO TARIFF APPENDIX F
Schedule 6

RCST SCHEDULES

Monthly RCST Charge

The Monthly RCST Charge shall be calculated by multiplying the monthly shaping factors by the target annual capacity price ($73/kW-yr).

Monthly Shaping Factors

	SP-15	NP-15/ZP-26
Jan	6.7%	4.9%
Feb	5%	4.9%
Mar	5%	5.6%
Apr	5.8%	4.6%
May	6.3%	4.8%
Jun	8.3%	5.1%
Jul	15.8%	13.7%
Aug	17.5%	15.3%
Sept	11.7%	13.8%
Oct	5.8%	8.7%
Nov	6.3%	8.8%
Dec	5.8%	9.8%
Total	100%	100%

Availability

The target Availability for a resource designated under RCST is 95%. Incentives and penalties for availability above and below the target are as set forth in the table below, entitled "Availability Factor Table." The ISO will calculate availability on a monthly basis using actual availability data. The "Availability Factor" for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability (excluding only Scheduled Maintenance)	Capacity Payment Factor	Availability Factor
100%	3.3%	1.139
99%	3.3%	1.106
98%	3.3%	1.073
97%	2.5%	1.040
96%	1.5%	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*	.908-.755
79-41%	-1.9%*	.736-.014
-40%	-	0.0

*The "Capacity Payment Factor" decreases by 1.7% and 1.9% respectively for every 1% decrease in availability.

The capacity payment will be adjusted upward from the 95% Availability starting point by the positive percentages listed as the Capacity Payment Factor above, by the amounts listed for each availability factor above 95%, so that, for example, if a 97% Availability is achieved for the month (as described below), then the capacity payment for that month would be the monthly value for 95% plus an additional 4% (1.5% for the first percent Availability above 95%, and 2.5% for the second percent Availability above 95%). Reductions in capacity payment will be made correspondingly according to the Capacity Payment Factor above for monthly availability levels falling short of the 95% availability starting point.

Calculation of the Monthly PER

The ISO shall calculate the Monthly Peak Energy Rent ("Monthly PER") as follows: immediately following the end of the month the ISO will determine all those hours during which the Reference Resource would have been dispatched (based on Reference Resource characteristics) to provide either energy or non-spinning reserves and will calculate, on a per kW-Month basis, the total dollar amount of rent (earnings in excess of proxy unit variable costs calculated using Reference Resource unit characteristics) that would have been earned by the Reference Resource. The Reference Resource will be assumed to have been dispatched for energy in any hour in which the hourly energy price described below is greater than the Reference Resource variable cost; the ISO shall use its day ahead Non-spinning Reserve price to calculate the rent for all hours in which the Reference Resource is not assumed dispatched to provide energy (i.e., any hour where the hourly price is less than the Reference Resource variable costs).

Hourly price profiles will be determined using the shaping factors for SP-15 and NP15/ZP-26 that appear below. Hourly energy prices shall be the weighted average of: (1) the applicable zonal on/off peak day-ahead index prices set forth in Platts Megawatt Daily, shaped to hourly profiles using the factors set forth below, and (2) the applicable zonal ISO hourly average real-time energy prices. For 2006, the index/ex post weighting will be 50/50, respectively. For 2007, the index/ex post weighting will be 75/25, respectively.

The assumed heat rate of the Reference Resource will be 10,500 BTU/kWh. Variable operations and maintenance costs shall be based on the Energy Information Administration AEO Electricity Market Module Assumptions, which are currently \$3.16/MWh. An emissions allowance of \$0.71/MWh shall be used to estimate variable costs. Gas prices for the Reference Resource will be based on a daily gas price based on 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 is served from one of those three Service Areas then from the nearest of those Service Areas.

NP-15

	Mon-Fri JAN-MAY	Mon-Fri JUN-SEPT	Mon-Fri OCT-DEC	Sat JAN-MAY	Sat JUN-SEPT	Sat OCT-DEC	Sun JAN-MAY	Sun JUN-SEPT	Sun OCT-DEC
N1	1.05454758	1.00584021	0.99435526	1.43649	1.120844	1.073148	0.755403	0.759704	0.783346
N2	0.85716711	0.86062114	0.91898795	1.032749	1.092377	0.978957	0.600188	0.683139	0.701588
N3	0.75399836	0.79068297	0.92144851	0.758585	0.91744	0.921009	0.458319	0.636187	0.68291
N4	0.71058351	0.79900018	0.89479611	0.680278	0.892744	0.911836	0.444573	0.616409	0.662295
N5	0.78267681	0.8161591	0.94516384	0.630256	0.909543	0.926083	0.362844	0.5641	0.662342
N6	1.02256586	0.86829359	1.10962719	0.623168	0.709153	0.947344	0.293086	0.335463	0.707489
N7	0.75351629	0.46629678	0.84979936	0.459933	0.363102	0.835985	0.324748	0.244038	0.795325
N8	0.88610975	0.66277777	0.86218587	0.741872	0.587123	0.805198	0.576432	0.514076	0.804009
N9	0.93647065	0.72748598	0.87228518	0.967023	0.960062	0.891018	0.923411	0.756354	0.873764
N10	0.98013307	0.83355915	0.99306313	1.050452	0.998448	0.917894	1.087891	0.848836	0.970588
N11	1.05081328	0.91348904	0.97923559	1.079888	0.984474	1.02248	1.303241	0.94756	1.027355
N12	1.068781	0.96178966	0.98802244	1.086984	1.03194	0.961419	1.304385	1.158765	1.097895
N13	1.06644102	1.07695356	0.99576872	1.083005	1.00669	0.992817	1.283414	1.168292	1.059999
N14	1.09775977	1.22226563	1.06440722	1.072448	1.0038	1.04347	1.281892	1.283789	1.110655
N15	1.09364901	1.38229366	1.11766171	1.053707	1.124805	1.05608	1.263359	1.309879	1.150637
N16	1.0841716	1.44680734	1.14665908	1.048562	1.135933	1.056274	1.316946	1.317595	1.140864
N17	1.02358917	1.3710053	1.1033917	1.049893	1.362503	1.087482	1.311524	1.567664	1.232842
N18	0.9788975	1.21057642	0.95748393	1.049616	1.327635	1.081109	1.30229	1.71578	1.406331
N19	0.94570613	1.03868542	1.10717179	1.036387	1.126072	1.09328	1.321985	1.367096	1.419466
N20	0.96174495	0.91022871	1.13578926	1.048527	0.943973	1.193558	1.393578	1.139089	1.494944
N21	1.11577915	0.94038191	1.03355639	1.133815	1.001619	1.076201	1.778309	1.551657	1.39373
N22	0.95643767	0.8354037	0.79351865	1.037886	1.04182	0.885733	1.392837	1.473652	1.062792
N23	1.56132501	1.66415743	1.17445625	1.670367	1.287221	1.205472	1.150247	1.253671	0.972486
N24	1.25713576	1.19524538	1.04116487	1.168106	1.070678	1.036151	0.769097	0.787205	0.786348

SP-15

Weekday January through June

Hour	January	February	March	April	May	June
1	0.9	0.97	1.018	0.973	0.951	0.945
2	0.858	0.908	0.896	0.902	0.839	0.826
3	0.839	0.885	0.828	0.849	0.758	0.745
4	0.836	0.876	0.821	0.824	0.717	0.727
5	0.887	0.977	0.946	0.878	0.879	0.794
6	1.155	1.11	1.068	1.008	1.086	0.908
7	0.898	0.933	0.79	0.779	0.6	0.474
8	1.007	1	0.892	0.92	0.778	0.613
9	1.017	1.004	0.941	0.94	0.875	0.711
10	1.011	1.019	0.983	0.991	0.976	0.806
11	0.976	0.994	1.027	1.024	1.035	1.04
12	0.98	0.99	1.038	1.038	1.074	1.087
13	0.972	0.994	1.055	1.075	1.126	1.127
14	0.983	0.984	1.06	1.098	1.193	1.201
15	0.955	0.963	1.039	1.072	1.175	1.247
16	0.896	0.932	0.994	1.031	1.147	1.26
17	0.899	0.905	0.956	0.965	1.089	1.216
18	1.171	1.044	0.983	0.914	0.997	1.12
19	1.158	1.136	1.167	0.944	0.882	1.012
20	1.075	1.067	1.082	1.06	0.965	0.965
21	1.059	1.06	1.048	1.14	1.153	1.119
22	0.941	0.975	0.946	1.009	0.935	0.999
23	1.371	1.213	1.305	1.383	1.536	1.733
24	1.153	1.062	1.117	1.183	1.235	1.322

Saturday January through June

Hour	January	February	March	April	May	June
1	0.999	1.073	1.104	0.982	1.071	1.064
2	0.905	0.971	0.922	0.917	0.957	0.882
3	0.899	0.962	0.889	0.883	0.839	0.828
4	0.875	0.93	0.868	0.855	0.814	0.803
5	0.91	0.917	0.88	0.904	0.826	0.788
6	0.972	0.993	0.88	0.969	0.836	0.818
7	0.795	0.854	0.777	0.761	0.603	0.411
8	0.874	0.906	0.844	0.848	0.728	0.522
9	0.992	1.015	0.932	0.929	0.885	0.645
10	1.028	1.037	0.997	0.999	0.984	0.806
11	1.005	1.048	1.027	1.042	1.047	1.055
12	1.005	1.033	1.027	1.053	1.069	1.089
13	0.978	1.009	1.032	1.054	1.096	1.122
14	0.939	0.967	0.983	1.042	1.093	1.165
15	0.882	0.939	0.963	1.022	1.086	1.203
16	0.871	0.892	0.949	0.973	1.071	1.255
17	0.945	0.899	0.934	0.962	1.063	1.254
18	1.196	1.03	1.016	0.912	1.011	1.17
19	1.195	1.155	1.199	1.047	0.934	1.075
20	1.141	1.076	1.165	1.113	1.058	0.984
21	1.114	1.104	1.133	1.165	1.237	1.143
22	1.04	1.036	1.022	1.076	1.035	1.102
23	1.323	1.117	1.331	1.327	1.478	1.622
24	1.117	1.038	1.126	1.164	1.18	1.194

Sunday January through June

Hour	January	February	March	April	May	June
1	0.897	0.85	0.787	0.869	0.794	0.854
2	0.806	0.792	0.762	0.771	0.7	0.7
3	0.745	0.802	0.716	0.732	0.628	0.622
4	0.706	0.802	0.695	0.722	0.594	0.519
5	0.707	0.794	0.707	0.696	0.623	0.469
6	0.782	0.793	0.72	0.671	0.585	0.445
7	0.818	0.873	0.691	0.711	0.471	0.372
8	0.882	0.912	0.819	0.826	0.635	0.522
9	0.975	1.007	0.945	0.926	0.757	0.631
10	1.035	1.073	1.029	1.002	0.87	0.75
11	1.03	1.065	1.069	1.059	1.059	1.019
12	1.049	1.063	1.112	1.101	1.126	1.141
13	1.043	1.065	1.147	1.118	1.176	1.268
14	1.029	1.061	1.141	1.127	1.239	1.341
15	1.003	1.033	1.11	1.097	1.279	1.44
16	0.98	1.004	1.115	1.11	1.295	1.482
17	1.039	1.006	1.091	1.052	1.336	1.528
18	1.324	1.161	1.179	1.033	1.363	1.403
19	1.37	1.305	1.421	1.191	1.231	1.321
20	1.338	1.248	1.366	1.35	1.327	1.242
21	1.286	1.213	1.288	1.469	1.471	1.381
22	1.166	1.144	1.191	1.318	1.263	1.291
23	1.079	1.066	1.082	1.127	1.239	1.339
24	0.912	0.869	0.816	0.922	0.938	0.92

Weekday July through December

Hour	July	August	Septemb er	October	Novembe r	Decembe r
1	1.002	0.994	1.083	1.04	0.966	1.001
2	0.89	0.903	0.92	0.879	0.834	0.883
3	0.81	0.835	0.762	0.751	0.706	0.814
4	0.767	0.813	0.749	0.69	0.723	0.805
5	0.796	0.841	0.822	0.829	0.879	0.903
6	0.914	0.982	1.049	1.08	1.266	1.088
7	0.493	0.547	0.634	0.763	0.899	0.895
8	0.632	0.637	0.751	0.858	0.98	1.012
9	0.728	0.743	0.786	0.837	0.977	1.012
10	0.837	0.822	0.859	0.9	0.957	1.005
11	0.983	0.999	0.966	0.96	0.959	0.983
12	1.051	1.056	1.013	0.975	0.943	0.93
13	1.097	1.106	1.078	1.013	0.933	0.906
14	1.163	1.179	1.15	1.076	0.946	0.894
15	1.257	1.24	1.213	1.147	0.93	0.87
16	1.284	1.264	1.236	1.152	0.93	0.863
17	1.255	1.235	1.197	1.129	0.999	0.967
18	1.183	1.149	1.11	1.019	1.221	1.194
19	1.065	1.05	1.052	1.073	1.207	1.213
20	0.982	1.05	1.051	1.122	1.137	1.174
21	1.034	1.028	1.031	1.048	1.046	1.085
22	0.935	0.895	0.876	0.927	0.936	0.998
23	1.623	1.493	1.371	1.497	1.427	1.316
24	1.197	1.14	1.223	1.235	1.2	1.191

Saturday July through December

Hour	July	August	September	October	November	December
1	1.065	1.107	1.206	1.202	1.145	1.108
2	0.952	0.984	1.046	1.038	0.952	0.982
3	0.88	0.939	0.919	0.871	0.784	0.86
4	0.85	0.847	0.844	0.766	0.753	0.843
5	0.871	0.832	0.863	0.778	0.821	0.875
6	0.841	0.862	0.848	0.885	1.014	0.909
7	0.451	0.494	0.542	0.609	0.745	0.76
8	0.539	0.56	0.622	0.63	0.893	0.845
9	0.682	0.679	0.733	0.663	0.961	0.997
10	0.778	0.788	0.814	0.943	0.977	1.015
11	0.956	0.918	0.971	1.017	1.027	1.022
12	1.019	1.029	1.045	1.039	1.002	1
13	1.087	1.103	1.125	1.068	0.924	0.984
14	1.16	1.183	1.149	1.108	0.91	0.921
15	1.236	1.252	1.194	1.105	0.889	0.818
16	1.284	1.298	1.216	1.124	0.89	0.775
17	1.301	1.252	1.205	1.073	1.003	1.005
18	1.251	1.215	1.17	1.103	1.237	1.212
19	1.132	1.097	1.086	1.157	1.228	1.211
20	1.029	1.111	1.097	1.208	1.172	1.173
21	1.076	1.077	1.074	1.176	1.1	1.139
22	1.02	0.943	0.957	0.976	1.041	1.124
23	1.395	1.358	1.185	1.389	1.41	1.291
24	1.147	1.07	1.09	1.071	1.12	1.133

Sunday July through December

Hour	July	August	September	October	November	December
1	0.834	0.81	0.884	0.868	0.916	0.889
2	0.739	0.729	0.688	0.685	0.788	0.809
3	0.679	0.672	0.527	0.562	0.613	0.698
4	0.655	0.653	0.489	0.574	0.578	0.634
5	0.61	0.657	0.463	0.558	0.586	0.68
6	0.496	0.647	0.512	0.613	0.62	0.747
7	0.445	0.549	0.527	0.573	0.666	0.777
8	0.587	0.618	0.619	0.697	0.776	0.848
9	0.719	0.704	0.713	0.708	0.997	0.985
10	0.877	0.854	0.901	0.829	1.103	1.052
11	1.005	0.991	1.035	1.102	1.143	1.067
12	1.108	1.154	1.178	1.163	1.151	1.052
13	1.167	1.151	1.318	1.154	1.125	1.029
14	1.254	1.25	1.353	1.24	1.138	0.993
15	1.339	1.358	1.347	1.252	1.085	0.929
16	1.432	1.43	1.354	1.272	1.063	0.92
17	1.447	1.467	1.375	1.235	1.279	1.146
18	1.383	1.396	1.372	1.407	1.346	1.351
19	1.301	1.278	1.314	1.481	1.395	1.387
20	1.194	1.243	1.338	1.517	1.296	1.317
21	1.336	1.322	1.359	1.477	1.217	1.279
22	1.217	1.171	1.24	1.18	1.097	1.241
23	1.221	1.053	1.171	1.115	1.096	1.188
24	0.956	0.843	0.923	0.735	0.927	0.983

RCST Changes Made to Appendix P, Attachment A of the

Conformed S&R Tariff Filed on March 22, 2006

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ISO TARIFF APPENDIX P

Attachment A

Conduct Warranting Mitigation

ISO Market Monitoring Plan

Market Mitigation Measures

3 CRITERIA FOR IMPOSING MITIGATION MEASURES

3.1.1.1 Reference Levels

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

1. the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (Pmin) and maximum (Pmax) operating point.

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

   1. Excluding proxy and mitigated bids, the accepted bid, or the lower of the mean or the median of a resource's accepted bids if such a resource has more than one accepted bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for daily~~monthly~~ 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. ~~the proxy figure for natural gas prices posted on the ISO Home Page.~~ Accepted and justified bids above the applicable soft cap, as

set forth in Section 39.2 of this Tariff, will be included in the calculation of reference prices.

2. If the resource is a gas-fired unit that does not have significant energy limitations, the unit's default Energy Bid determined monthly as set forth in Section 5.11.5 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of $6/MWh).

3. For non gas-fired units and gas-fired units that have significant energy limitations, a level determined in consultation with the Market Participant submitting the bid or bids at issue, provided such consultation has occurred prior to the occurrence of the conduct being examined by the ISO, and provided the Market Participant has provided sufficient data on a unit's energy limitations and operating costs (opportunity cost for energy limited resources) in accordance with specifications provided by the ISO.

4. The mean of the Economic Market Clearing Prices for the units' relevant location (Zone or node commensurate with the pricing granularity in effect) during the lowest-priced 25 percent of the hours that the unit was dispatched or scheduled over the previous 90 days for peak and off-peak periods, adjusted for changes in fuel prices; or

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

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

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

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

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4 MITIGATION MEASURES

4.2 Sanctions for Economic Withholding

4.2.2 Implementation

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

(b) The Mitigation Measures will be applied to 1) all incremental bids submitted to the real-time Imbalance Energy market during the pre-dispatch process prior to the real-time Imbalance Energy market based on the projected real-time MCPs that are computed during this process; and 2) to the Day-Ahead and the Hour-Ahead Energy markets when these markets are made operational.

(c) An Electric Facility subject to a default bid shall be paid the MCP applicable to the output from the facility. Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the MCP applicable to that facility.

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

(e) The Mitigation Measures shall not be applied to Energy Bids projected to be Dispatched as Imbalance Energy through the RTD Software in the hours in which all Zonal Ex Post Prices are projected to be below $~~91.87~~200/MWh. If the Zonal Dispatch Interval Ex Post Price is projected to be above $~~91.87~~200/MWh in any ISO Zone, the Mitigation Measures shall be applied to all bids, except those from System Resources, in all ISO Zones. The ISO will apply Mitigation Measures to all bids taken out of merit order to address Intra-Zonal Congestion.

(f) The Mitigation Measures shall not be applied to bids below $25/MWh.

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

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

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ATTACHMENT B

RCST Example 1

Local Area Reliability Need	8000						Tier 1	Tier 2	
	Load in TAC Area Territory	Load Ratio Share of Load in TAC Area (%)	LARN Allocation	LARN Credits	Gross LARN Allocation	Net LARN Allocation IF LARN Credit >= LARN Allocation then 0, Otherwise (Gross Allocation-LARN Credits)	Cost Allocation of RCST Short-Fall Portion of RCST Designation	Cost Allocation for Balance of RCST Designation	Total Allocation of RCST Designation
Entity 1 Even	16000	80.00%	6,400	6,400	6,400	-	-	-	-
Entity 2 Even	3000	15.00%	1,200	1,200	1,200	-	-	-	-
Entity 3 Even	750	3.75%	300	300	300	-	-	-	-
Entity 4 Even	250	1.25%	100	100	100	-	-	-	-
Total:	*20000*	*100%*	*8,000*	*8,000*	*8,000*	-	-	-	-
Gross LARN Short-Fall				-					
RCST Desigation				-					
Total Credits + RCST Des.				8,000					

Example illustrates

Each entity meets LARN responsibility	Yes
In aggregate LARN requirements are satisfi	Yes
RCST is procured to meet shortfall	No
RCST is procured in excess of shortfall	No

** Note: unless designated differently, all units are in MW's*

RCST Example 2

Local Area Reliability Need	8000						Tier 1	Tier 2	
	Load in TAC Area Territory	Load Ratio Share of Load in TAC Area (%)	LARN Allocation	LARN Credits	Gross Local Allocation	Net Local Allocation IF LARN Credit >= LARN Allocation then 0, Otherwise (Gross Allocation-LARN Credits)	Cost Allocation of RCST Short-Fall Portion of RCST Designation	Cost Allocation for Balance of RCST Designation	Total Allocation of RCST Designation
Entity 1 Long	16000	80.00%	6,400	6,600	6,400	-	-	-	-
Entity 2 Even	3000	15.00%	1,200	1,200	1,200	-	-	-	-
Entity 3 Short	750	3.75%	300	150	300	150	-	-	-
Entity 4 Short	250	1.25%	100	50	100	50	-	-	-
Total:	*20000*	*100%*	*8,000*	*8,000*	*8,000*	*200*	-	-	-
Gross LARN Short-Fall				-					
RCST Desigation				-					
Total Credits + RCST Des.				8,000					

Example illustrates

Each entity meets LARN responsibility	No
In aggregate LARN requirements are satisfied	Yes
RCST is procured to meet shortfall	No
RCST is procured in excess of shortfall	No

** Note: unless designated differently, all units are in MW's*

RCST Example 3

Local Area Reliability Need	8000						Tier 1	Tier 2	
	Load in TAC Area Territory	Load Ratio Share of Load in TAC Area (%)	LARN Allocation	LARN Credits	Gross Local Allocation	Net Local Allocation IF LARN Credit >= LARN Allocation then 0, Otherwise (Gross Allocation-LARN Credits)	Cost Allocation of RCST Short-Fall Portion of RCST Designation	Cost Allocation for Balance of RCST Designation	Total Allocation of RCST Designation
Entity 1 Even	16000	80.00%	6,400	6,400	6,400	-	-	-	-
Entity 2 Even	3000	15.00%	1,200	1,200	1,200	-	-	-	-
Entity 3 Short	750	3.75%	300	150	300	150	150	-	150
Entity 4 Short	250	1.25%	100	50	100	50	50	-	50
Total:	*20000*	*100%*	*8,000*	*7,800*	*8,000*	*200*	*200*	-	*200*
Gross LARN Short-Fall				200					
RCST Desigation				200					
Total Credits + RCST Des.				8,000					

Example illustrates

Each entity meets LARN responsibility	No
In aggregate LARN requirements are satisfi	No
RCST is procured to meet shortfall	Yes
RCST is procured in excess of shortfall	No

** Note: unless designated differently, all units are in MW's*

RCST Example 4

Local Area Reliability Need	8000						Tier 1	Tier 2	
	Load in TAC Area Territory	Load Ratio Share of Load in TAC Area (%)	LARN Allocation	LARN Credits	Gross Local Allocation	Net Local Allocation IF LARN Credit >= LARN Allocation then 0, Otherwise (Gross Allocation-LARN Credits)	Cost Allocation of RCST Short-Fall Portion of RCST Designation	Cost Allocation for Balance of RCST Designation	Total Allocation of RCST Designation
Entity 1 Long	16000	80.00%	6,400	6,450	6,480	-	-	80	80
Entity 2 Even	3000	15.00%	1,200	1,200	1,215	-	-	15	15
Entity 3 Short	750	3.75%	300	200	304	104	67	4	71
Entity 4 Short	250	1.25%	100	50	101	51	33	1	34
Total:	*20000*	*100%*	*8,000*	*7,900*	*8,100*	*155*	*100*	*100*	*200*
Gross LARN Short-Fall				100					
RCST Desigation				200					
Total Credits + RCST Des.				8,100					

Example illustrates

Each entity meets LARN responsibility	No
In aggregate LARN requirements are satisfied	No
RCST is procured to meet shortfall	Yes
RCST is procured in excess of shortfall	Yes

** Note: unless designated differently, all units are in MW's*

RCST Example 5

Local Area Reliability Need	8000						Tier 1	Tier 2	
	Load in TAC Area Territory	Load Ratio Share of Load in TAC Area (%)	LARN Allocation	LARN Credits	Gross Local Allocation	Net Local Allocation IF LARN Credit >= LARN Allocation then 0, Otherwise (Gross Allocation-LARN Credits)	Cost Allocation of RCST Short-Fall Portion of RCST Designation	Cost Allocation for Balance of RCST Designation	Total Allocation of RCST Designation
Entity 1 Even	16000	80.00%	6,400	6,400	6,480	-	-	80	80
Entity 2 Even	3000	15.00%	1,200	1,200	1,215	-	-	15	15
Entity 3 Even	750	3.75%	300	300	304	-	-	4	4
Entity 4 Even	250	1.25%	100	100	101	-	-	1	1
Total:	*20000*	*100%*	*8,000*	*8,000*	*8,100*	-	-	*100*	*100*
Gross LARN Short-Fall				-					
RCST Desigation				100					
Total Credits + RCST Des.				8,100					

Example illustrates

Each entity meets LARN responsibility	Yes
In aggregate LARN requirements are satisfi	Yes
RCST is procured to meet shortfall	No
RCST is procured in excess of shortfall	Yes

** Note: unless designated differently, all units are in MW's*

RCST Example 6

Local Area Reliability Need	8000						Tier 1	Tier 2	
	Load in TAC Area Territory	Load Ratio Share of Load in TAC Area (%)	LARN Allocation	LARN Credits	Gross Local Allocation	Net Local Allocation IF LARN Credit >= LARN Allocation then 0, Otherwise (Gross Allocation-LARN Credits)	Cost Allocation of RCST Short-Fall Portion of RCST Designation	Cost Allocation for Balance of RCST Designation	Total Allocation of RCST Designation
Entity 1 Long	16000	80.00%	6,400	6,450	6,480	-	-	80	80
Entity 2 Even	3000	15.00%	1,200	1,200	1,215	-	-	15	15
Entity 3 Even	750	3.75%	300	300	304	-	-	4	4
Entity 4 Short	250	1.25%	100	50	101	51	-	1	1
Total:	*20000*	*100%*	*8,000*	*8,000*	*8,100*	*51*	-	*100*	*100*
Gross LARN Short-Fall				-					
RCST Desigation				100					
Total Credits + RCST Des.				8,100					

Example illustrates

Each entity meets LARN responsibility	No
In aggregate LARN requirements are satisfi	Yes
RCST is procured to meet shortfall	No
RCST is procured in excess of shortfall	Yes

** Note: unless designated differently, all units are in MW's*

Certificate of Service

I hereby certify that I have this day served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceedings, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 31st day of March, 2006 at Folsom in the State of California.

Charity Wilson Hmm

Charity Wilson
(916) 608-7147