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March 15, 2007

VIA MESSENGER

The Honorable Philis J. Posey
Acting 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-___
Compliance Filing

Dear Secretary Posey:

The California Independent System Operator Corporation ("CAISO")[1] respectfully submits its filing in compliance with the "Order on Paper Hearing" issued by the Commission in the captioned proceeding on February 13, 2007, 118 FERC ¶ 61,096 ("February 13 Order").

I. Background

On March 31, 2006, the Independent Energy Producers Association, the CAISO, the California Public Utilities Commission, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (together, the "Settling Parties") submitted an Offer of Settlement and Explanatory Statement in the captioned proceeding ("Offer of Settlement") in order to resolve all issues in the proceeding. The Offer of Settlement included, for illustrative purposes, tariff sheets reflecting the amendments to the ISO Tariff that would be necessary to implement the terms of the Offer of Settlement. In the Offer of Settlement, the Settling Parties also stated that, following Commission approval of the Offer of the Settlement, the CAISO would make a

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1 Capitalized terms not otherwise defined herein have the meanings set forth in the Master Definitions Supplement, Appendix A to the ISO Tariff.

compliance filing to incorporate the tariff provisions into the ISO Tariff. Transmittal Letter for Offer of Settlement at 1.

On July 20, 2006, the Commission issued its "Order on Complaint and Offer of Settlement" in the proceeding, 116 FERC ¶ 61,069 ("July 20 Order"). In the July 20 Order, the Commission, *inter alia*, made the following determinations: (i) it found that, pursuant to Section 206 of the Federal Power Act ("FPA"), compensation to generators under the must-offer obligation is no longer just and reasonable; (ii) the Commission instituted paper hearing procedures in the proceeding under Section 206 of the FPA to review evidence on whether the rates and cost allocation mechanism under the Offer of Settlement or some other rates and cost allocation are just and reasonable with respect to the must-offer obligation; (iii) the Commission permitted each seller of Eligible Capacity as defined under the terms of the Offer of Settlement, at its election, to collect the Offer of Settlement rates from the date of the July 20 Order, so long as such seller agrees that all of these revenues will be subject to refund, even if they are collected after the statutory refund period ends; and (iv) the Commission established a refund effective date, pursuant to Section 206(b) of the FPA, of August 26, 2005 (the date the complaint that initiated this proceeding was filed). July 20 Order at PP 38, 40, Ordering Paragraphs (A), (B), (E).

On September 27, 2006, the Commission issued its "Order on Clarification" in the proceeding, 116 FERC ¶ 61,297 ("September 27 Order"). In the September 27 Order, the Commission clarified that it was permitting implementation, on an interim basis and subject to refund, of the rates proposed in the Offer of Settlement. The Commission directed the CAISO to "make a compliance filing to implement the Offer of Settlement rates as directed in the July 20 [O]rder and as clarified herein." September 27 Order at P 10. The Commission stated in the September 27 Order that, upon approval of appropriate interim tariff sheets, the CAISO would be authorized to implement all of the terms of the Offer of Settlement relating to the sale of capacity, and that each potential seller of capacity under the RCST could collect the Offer of Settlement rates if the seller made an election pursuant to the July 20 Order and the clarifications provided in the September 27 Order. Specifically, the Commission noted that its approvals encompassed provisions in the Offer of Settlement establishing must-offer capacity payment rates, Reliability Capacity Services Tariff ("RCST") rates due to designation resulting from a Significant Event, RCST rates due to designation resulting from deficiency in Resource Adequacy showings, and payments to frequently mitigated units. *Id.* at P 14. The Commission also stated that the interim tariff sheets should include the cost allocation methodologies as proposed in the Offer of Settlement and should include all reporting and procedural requirements set forth in the Offer of Settlement. *Id.* at PP 15, 18. The Commission stated that it was not authorizing the CAISO to implement, on an interim basis, the provisions in the Offer of Settlement relating to Automatic Mitigation Procedures ("AMP") and the treatment of Ancillary Services bids from certain RMR Condition 2 units. *Id.* at P 15 (citing Sections 5.1 and 9.2 of the Offer of Settlement).

Pursuant to these directives, the CAISO submitted a compliance filing on October 20, 2006, that contained tariff sheets reflecting the provisions of the Offer of Settlement that the Commission had approved for implementation on an interim basis. The filed tariff sheets were based on the *pro forma* tariff sheets filed with the Offer of Settlement with modifications to reflect the following: (1) the fact that there would not be any 2006 forward local RCST designations; (2) other language changes resulting from the removal of the 2006 local RCST tariff provisions; (3) certain modifications to comply with the directives in the July 20 and September 27 Orders; (4) elimination of the AMP and RMR Condition 2 tariff provisions; and (5) certain ministerial/clean-up language changes.

In its February 13 Order, the Commission approved all provisions of the Offer of Settlement except (1) the increased AMP price screen, and (2) the proposed treatment of Ancillary Services bids from RMR Condition 2 units – the two provisions that the CAISO had not included in the compliance filing tariff sheets filed on October 20, 2006. February 13 Order at PP 69-77, 86-89, 97-99, 122-126, 132, 140-42, 153-54, 158, 164-66, 176-78, 187, 197-98. The Commission directed the CAISO to file tariff sheets to implement the Offer of Settlement as modified in the February 13 Order. The Commission also ruled that the Offer of Settlement should be made effective June 1, 2006. *Id.* at P 200. In addition, the Commission stated that it would address the CAISO's October 20, 2006, compliance filing in a subsequent order. *Id.* at P 10 n.14.

II. Materials Included in This Compliance Filing

The tariff language contained in the instant compliance filing is black-lined against the tariff language contained in the October 20, 2006, compliance filing, which was intended to implement the provisions Offer of Settlement (except the two provisions identified above) on an interim basis.

The changes contained in the instant compliance filing fall into five categories. First, the revised tariff sheets reflect the removal of certain language in Sections 34.1.2.1.1 and 40.14 of the ISO Tariff that was included in the October 20, 2006, compliance filing in recognition of the notice requirements that the Commission had imposed in connection with the payment of Offer of Settlement charges on an interim basis. Because the notice/refund provisions no longer apply, the CAISO has removed the pertinent language from the ISO Tariff.

Second, the compliance filing contains a revision to Section 43.5.1 of the ISO Tariff to more accurately reflect the language in the Offer of Settlement regarding the obligation of Eligible Capacity designated as RCST to offer Ancillary Services. In that regard, Williams Power Company, Inc. ("Williams"), in its comments on the October 20, 2006, compliance filing, asserted that the CAISO should modify Section 43.5.1 to make it clear that, as stated in Section 4.3 of the Offer of Settlement and the accompanying Explanatory Statement, once RCST capacity has been designated, such RCST capacity must offer Ancillary Services to the extent capable. The ISO Tariff language included in the Section 43.5.1 of the October 20, 2006, compliance filing possibly could have been read as imposing on non-RCST designated units a must-offer obligation to bid in Ancillary Services. In its November 28, 2006, answer in this proceeding, the CAISO indicated that it did not object to making that change requested by Williams and hereby makes such change in the instant filing.

Third, the clean ISO Tariff sheets provided in Attachment A to this filing reflect a June 1, 2006 effective date, in accordance with the February 13 Order.

Fourth, the instant compliance filing corrects a pair of inadvertent errors in the ISO Tariff language that was filed on October 20, 2006. These errors were previously identified by the California Department of Water Resources State Water Project ("SWP") in their protest of the October 20, 2006, compliance filing. The two inadvertent errors and the CAISO's corrections are as follows:

- The references to Section 43.9 in Section 40.14 of the ISO Tariff and in the definition of Must-Offer Capacity Payment are incorrect. The correct references should both be to Section 40.14. The CAISO has made those corrections herein.

- Appendix A to the ISO Tariff does not include a definition of "SC-RA Entity." This definition was inadvertently omitted from the October 20, 2006, compliance filing. "SC-RA Entity," is defined in Section 2.2.2(a) of the Offer of Settlement as a "Scheduling Coordinator for an RA Entity," and the CAISO has included that definition in Appendix A in the instant filing.

The Commission did not require these corrections in the February 13 Order. The CAISO respectfully requests that the Commission waive any requirement that this compliance filing must include only those changes specifically directed in the February 13 Order, as well as any other requirements that might preclude this correction.

Fifth, due to an administrative error, clean ISO Tariff Sheet Nos. 515 and 515A, as filed in the October 20, 2006, compliance filing, did not take account of revisions to those sheets proposed in the August 23, 2006, tariff amendment filing regarding Low Voltage Transmission Revenue Requirements ("LVTRR") submitted in Docket No, ER06-1395-000, which the Commission accepted in a letter order issued on October 18, 2006. Attachments A and C in the instant compliance filing include clean ISO Tariff sheets correcting this error.

Attachment A includes Sheet Nos. 515 and 515A covering the period from June 1, 2006 to October 22, 2006; consistent with the guidelines for tariff sheet designation contained in the Commission's Order No. 614,[2] these sheets are paginated as "squeezed" sheets, inasmuch as they cover the period prior to the effective date of the LVTRR changes, although they were issued after the LVTRR amendment tariff sheets. Attachment C includes Sheet Nos. 515 and 515A effective October 23, 2006, which incorporate the changes to those sheets made in the LVTRR amendment filing, and therefore are paginated as a later revision than the LVTRR tariff sheets.[3]

III. Conclusion

The changes that fall under the first four categories described above are shown in the revised ISO Tariff sheets provided in Attachment A to the instant filing. They are also shown in black-line format in Attachment B to the instant filing. The changes that fall under the fifth category are shown in Attachments A and C to the instant filing as described above.

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,

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2 *See Designation of Electric Rate Schedule Sheets*, Order No. 614, 65 Fed. Reg. 18221, FERC Stats. & Regs. ¶ 31,096, at 31,510, 31,512 (2000).

3 *See id.*

Attachment A – Clean Sheets

Reliability Capacity Services Tariff Settlement Filing

Docket EL05-146-000

T 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

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 40.14 during that month, (ii) the total Imbalance Energy payments received when that Generating Unit is running at minimum load, and (iii) the Frequently Mitigated Adder under Section 34.1.2.1.1 during the calendar month, exceeds the Qualifying Capacity times the maximum Monthly RCST Charge (established in Schedule 6 of Appendix F) reduced by the Monthly PER (established in Schedule 6 of Appendix F), the FERC Must-Offer Generator shall not be eligible to receive Must-Offer Capacity Payments or the Frequently Mitigated Adder under Section 34.1.2.1.1 for that Generating Unit for that Trading Day, nor for any other Trading Day in the remainder of the calendar month (but shall continue to recover Minimum Load Costs and imbalance Energy payments). This Section 40.14 shall expire at midnight on the earlier of December 31, 2007 or the date immediately before the MRTU goes into effect.

40.14.1 Allocation of Must-Offer Capacity Payments

The ISO shall determine whether the Must-Offer Capacity Payment costs for each FERC Must-Offer Generator Generating Unit operating during a waiver denial period are due to (1) local reliability requirements, (2) zonal requirements, or (3) Control Area-wide requirements. For each month, the ISO shall sum the Must-Offer Capacity Payments costs and shall allocate those costs as follows:

(1) if the Generating Unit was operating to meet local reliability requirements, the Must-Offer Capacity Payment costs shall be considered incremental locational costs and shall be allocated in accordance with Section 40.8.6 (1).

(2) if the Generating Unit was operating due to Zonal requirements, the Must-Offer Capacity Payment costs shall be allocated in accordance with Section 40.8.6 (2)

(3) if the Generating Unit was operating to satisfy an ISO Control Area-wide need, the Must-Offer Capacity Payment costs shall be allocated in accordance with Section 40.8.6 (3).

40.15 Must-Offer Reporting Requirements

Sections 40.15 through 40.15.4 shall expire at midnight on the earlier of December 31, 2007 or the date immediately before the MRTU goes into effect.

40.15.1 Must-Offer Waiver Denial Report

The ISO shall publish a Must-Offer Waiver Denial Report ("MOWD Report") on the ISO Website on a weekly basis and shall provide a market notice of its availability. The MOWD Report shall indicate the category of the must-offer waiver denial, *i.e.,* local, zonal or system, and the amount of megawatts involved in each category. On a daily basis, thirty (30) days after the Trade Day, the ISO will publish on OASIS the allocation of Un-Recovered Minimum Load Costs for RCST and Resource Adequacy Resources and Minimum Load Costs for FERC Must-Offer Generators.

40.15.2 Monthly Minimum Load Cost Report

On a monthly basis, thirty (30) days after the Trade Day, the ISO will publish on ISO Website, the monthly allocation of Un-Recovered Minimum Load Costs for RCST and Resource Adequacy Resources, Minimum Load Costs for FERC Must-Offer Generators.

40.15.3 Multiple Denial of FERC Must-Offer Waivers

If the ISO issues a denial of must-offer waivers to a FERC Must-Offer Generator on four separate days in any calendar year, the ISO shall evaluate whether a Significant Event has occurred that warrants designation of the FERC Must-Offer Generator to provide service under the RCST ("MOWD Evaluation").

The ISO shall conduct a MOWD Evaluation after every four separate days on which the ISO denies a must-offer waiver request for such a FERC Must-Offer Generator.

40.15.4 Significant Event/Repeat Waiver Denial Report

The ISO shall publish the results of its assessment of the MOWD Evaluation ("Significant Event/Repeat MOWD Report"), including an explanation of its decision whether to designate FERC Must-Offer Generator capacity as RCST, on the ISO Website on a weekly basis unless no Significant Events or MOWD Evaluations occurred during the week. The ISO will provide a market notice of the availability of each Significant Event/Repeat MOWD Report. The Significant Event/Repeat MOWD Report shall explain why the ISO denied the must-offer waiver request that triggered the assessment of whether a Significant Event occurred, and whether any Resource Adequacy Resources, RMR units, or resources designated to provide service under the RCST were available and called upon by the ISO prior to its denial of the FERC Must-Offer Generator's must-offer waiver request. The ISO shall also explain why Non-Generation Solutions were insufficient to prevent the use of denials of must-offer waivers for local reasons. In the event that the ISO denies a must-offer waiver request for local or system reasons that do not constitute a Significant Event or is not due to a Resource Adequacy Resource non-performance, the report shall include an explanation for such issuance and shall be signed by the ISO's Vice President of Operations.

41 Procurement of RMR.

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

42.1 Generation Planning Reserve Criteria.

Generation planning reserve criteria shall be met as follows:

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

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

42.1.3 If the forecast shows that the applicable WECC/NERC Reliability Criteria cannot be met during peak Demand periods, then the ISO shall facilitate the development of market mechanisms to bring the ISO Controlled Grid during peak periods into compliance with the Applicable Reliability Criteria (or such more stringent criteria as the ISO may impose pursuant to Section 7.2.2.2). The ISO shall solicit bids for Replacement Reserve in the form of Ancillary Services, short-term Generation supply contracts of up to one (1) year with Generators, and Load curtailment contracts giving the ISO the right to reduce the Demands of those parties that win the contracts when there is insufficient Generation capacity to satisfy those Demands in addition to all other Demands. The curtailment contracts shall provide that the ISO's curtailment rights can only be exercised after all available Generation capacity has been fully utilized unless the exercise of such rights would allow the ISO to satisfy the Applicable Reliability Criteria at lower cost, and the curtailment rights shall not be exercised to stabilize or otherwise influence prices for power in the Energy markets.

Reserve in the hour, determined in accordance with Section 8.12.3A bears to the total deviation Replacement Reserve in that hour.

43 Reliability Capacity Services Tariff

This section 43 of the ISO Tariff shall be referred to as the Reliability Capacity Services Tariff ("RCST"). The RCST as well as changes made to other Sections to implement the Offer of Settlement filed on March 31, 2006 in Docket No. EL05-146 (changes to Sections 34.1.2.1.1; 34.1.2.1.2; 40.6A.6; 40.7.1; 40.7.6; 40.14; 40.14.1; 40.15; 40.15.1; 40.15.2; 40.15.3; 40.15.4; Appendix F Schedule 6; and Appendix P, Attachment A) shall expire at midnight on the earlier of December 31, 2007 or the date immediately before the ISO's MRTU Tariff goes into effect, except that the provisions concerning compensation, cost allocation and settlement shall remain in effect until such time as RCST resources have been finally compensated for their services rendered under the RCST prior to the termination of the RCST, and the ISO has finally allocated and recovered the costs associated with such RCST compensation.

43.1 Designation

The ISO shall have the authority provided in this Section 43.1 to designate Eligible Capacity or System Resources to provide services under the RCST as set forth in this Section 43.

43.2 Local RCST Designations

The ISO may designate Eligible Capacity to provide services under the RCST to meet local reliability needs to the extent provided in this Section 43.2.

43.2.1 2007 Local RCST Designations

For 2007, the CPUC and Local Regulatory Authorities may establish Local Resource Adequacy Requirements for the RA Entities subject to their respective jurisdictions. 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 43.2.2, 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 43.2.1 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.

43.2.2 Selection of Eligible Capacity Designated for Local Reliability

The ISO will make designations of Eligible Capacity under Section 43.2 based on the lowest overall cost for each 2007 Local Reliability Area considering the following factors: the effectiveness of the Eligible Capacity, the quantity of Eligible Capacity of the resource relative to the remaining amount of capacity that is needed; and the Start-Up and Minimum Load Costs associated with the Eligible Capacity. The ISO shall have reasonable allowance to designate under the RCST an amount of Eligible Capacity from a Generating Unit that is slightly more or slightly less than a deficiency due to the quantity of Eligible Capacity from such Generating Unit that is available and suitable to meet the deficiency, consistent with the criteria in this section.

43.3 System RCST Designations

The ISO may designate Eligible Capacity for calendar years 2006 and 2007 to the extent provided in this Section 43.3.

43.3.1 Annual System Reliability Capacity Services Designations

No sooner than May 17, 2006, and following the ISO's review of the annual Resource Adequacy Plans submitted pursuant to Section 40.2.1 and, for 2007, any designation of Eligible Capacity pursuant to Section 43.2.1, the ISO may designate Eligible Capacity or System Resources to provide services under the RCST under this Section 43.3 to the extent necessary to cover the aggregate Year-Ahead System Resource Deficiency consistent with the criteria set forth in Section 43.3.3.

A designation of Eligible Capacity or System Resources to provide services under the RCST made pursuant to this Section 43.3.1 shall be for a minimum term of three months, provided that, at the discretion of the ISO, the designation term during 2006 may be extended to a maximum of the four summer months of June through September and, for 2007, the designation term during 2007 may be extended up to a maximum term of the five summer months of May through September.

43.3.2 Monthly System Reliability Capacity Services Designations

Following its review of the monthly Resource Adequacy Plans submitted by Scheduling Coordinators pursuant to Section 40.2.2, the ISO may designate Eligible Capacity or System Resources to provide services under the RCST under this Section 43.3 to the extent necessary to cover the aggregate Month-Ahead System Resource Deficiency consistent with the criteria set forth in Section 43.3.3.

Designations of Eligible Capacity or System Resources to provide services under the RCST made pursuant to this Section 43.3.2 shall be for the lesser of three months, the remainder of the calendar year or the period of time until the MRTU Tariff becomes effective.

43.3.3 Selection of Eligible Capacity Designated for System Reliability

The ISO will make designations of Eligible Capacity or System Resources under this Section 43.3 based on the following factors: the effectiveness of the Eligible Capacity in addressing local and/or zonal constraints in addition to meeting system needs; the quantity of Eligible Capacity of the resource; the Start-Up and Minimum Load Costs associated with the Eligible Capacity; and the effectiveness of the Eligible Capacity at reducing the Minimum Load Costs that might otherwise be incurred as a result of must-offer waiver denials. System Resources shall be subject to the ISO's established import limits as specified in accordance with Section 40.5.2.2. The ISO shall have reasonable allowance to designate under the RCST an amount of Eligible Capacity from a Generating Unit or System Resource that is slightly more or slightly less than a deficiency due to the quantity of Eligible Capacity from such Generating Unit or System Resource that is available and suitable to meet the deficiency, consistent with the criteria in this section.

43.4 RCST Designations For Significant Events

The ISO may designate Eligible Capacity or System Resources to provide service under this Section 43.4 following a Significant Event, and taking into account the expected duration of the Significant Event, if such an RCST designation is necessary to remedy any resulting material difference in ISO Controlled Grid operations relative to the assumptions reflected in the LARN Report for 2006 or relative to the assumptions underlying the CPUC's and, if applicable, a Local Regulatory Authority's development of Local Resource Adequacy Requirements for 2007. An RCST designation due to a Significant Event shall have a minimum term of three months and a maximum term up to the period of time which the ISO determines the Significant Event will remain in effect, provided that in no event shall the term of such RCST designation extend beyond the earlier of midnight on December 31, 2007 or midnight the day before the effective date of MRTU implementation. Any RCST designations under this section shall be in accordance with the criteria set forth in Section 43.3.3.

43.5 Obligations of a Resource Designated under the RCST

43.5.1 Must-Offer Obligations

Generating Units designated under the RCST shall be subject to all of the availability, must-offer, dispatch, testing, reporting, and verification obligations applicable to Resource Adequacy Resources identified in Resource Adequacy Plans under Section 40.6A of the ISO Tariff. Generating Units designated under the RCST must offer available capacity into the Ancillary Services markets to the extent capable.

43.5.2 Replacement Option

If a Generating Unit designated under the RCST is unavailable when issued a must-offer waiver denial by the ISO pursuant to Section 40.7.6 of the ISO Tariff, the Scheduling Coordinator for the resource may, within 2 hours for a must-offer waiver denial issued prior to the Hour-Ahead market and within 30 minutes for a must-offer waiver denial issued in Real-Time, substitute capacity from such Generating Unit with Eligible Capacity that: (i) is located at the same bus, or (ii) if not located at the same bus, is located in the same Local Reliability Area or 2007 Local Reliability Area, whichever is applicable, and which meets the ISO's effectiveness and operational needs, including size of resource, as determined by the ISO in its reasonable discretion. If the Scheduling Coordinator substitutes such Eligible Capacity, the Scheduling Coordinator must pay all additional Minimum Load Costs, Start-Up Costs, Emissions Costs (above the corresponding costs of the Generating Unit that is being substituted), and any bilateral contract costs incurred by the Scheduling Coordinator, as a result of the substitution. The actual Availability of the substitute resource will be used for the purposes of the calculations in Appendix F, Schedule 6.

43.5.3 Termination of Obligations

If a Participating Generator's Eligible Capacity is designated by the CAISO under the terms of the RCST, and the Participating Generator has not filed a notice to withdraw from the Participating Generator Agreement ("PGA"), then the Participating Generator shall be obligated to perform in accordance with the RCST for the term of the RCST designation. If a Participating Generator's Eligible Capacity is designated under the terms of the RCST after the Participating Generator has filed a notice to withdraw from its PGA, then the Participating Generator shall be obligated to perform in accordance with the RCST until the date that its PGA effectively terminates, but the Participating Generator shall be under no obligation to so perform after the effective date of the PGA termination. If a Participating Generator's Eligible Capacity is designated under the RCST after the Participating Generator has filed notice to withdraw from its PGA, and the Participating Generator agrees to provide service under the RCST, then the Participating Generator will enter into a PGA for the designated generating unit and invoice the ISO for any actual applicable restoration costs as provided in the RMR Service Agreement.

43.6 RCST Report

The ISO shall publish a monthly report on the ISO Website which shall show the resources designated under RCST, the megawatts of each RCST capacity designation, the duration of RCST designations, the reason for the RCST designation, and all payments, excluding costs covered in the Minimum Load Cost Report described in Section 43.11.2 herein, in dollars, itemized for system purposes as well as for each Local Reliability Area or 2007 Local Reliability Area, whichever is applicable. The ISO will provide a market notice of the availability of this report.

43.7 Payments to Resources Designated Under the RCST

43.7.1 RCST Capacity Payment

Scheduling Coordinators representing resources designated under this Section 43 will receive a RCST Capacity Payment equal to the product of the Net Qualifying Capacity, the relevant Availability Factor as determined in accordance with Appendix F, Schedule 6, and the difference between the monthly RCST charge and 95% of the Peak Energy Rent, *i.e.,* Net Qualifying Capacity x Availability Factor x (Monthly RCST Charge (Monthly Peak Energy Rent x .95)). The ISO shall determine the Availability Factor, Monthly RCST Charge and Monthly Peak Energy Rent in accordance with Appendix F, Schedule 6 of the Tariff. For purposes of this section 43.7.1, the term Net Qualifying Capacity shall mean the Megawatt value for a RCST resource as reflected in the document entitled Qualifying Capacity Megawatt Values for RA Planning Purposes (or any successor document) as posted on the ISO website, provided that, to the extent a particular resource has a stated monthly value(s), the applicable Net Qualifying Capacity shall be the average of the stated values for the months in which the resource will have an RCST designation.

For purposes of the RCST, Availability shall be calculated as the ratio of: (1) the sum of the Net Qualifying Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the ISO shall be substituted for Net Qualifying Capacity MW for each hour the resource is not on an Authorized Outage, to (2) the product of Net Qualifying Capacity MW and the total hours in the month. For purposes of this section, an Authorized Outage shall be limited to the following: (a) an ISO-approved, planned outage that exists at the time of RCST designation and is scheduled to occur during the term of an RCST designation provided that (i) such outage is not the result of a prior outage that was forced or not otherwise scheduled and approved by the ISO, and (ii) such outage may be rescheduled by the ISO during the term of the RCST designation period, provided that the term of the ISO-approved outage and the capacity derate at time of the RCST designation are not exceeded, or (b) an ISO-approved maintenance outage that is scheduled during the RCST designation period, provided such outage is not the result of a prior outage that was forced or not otherwise scheduled and approved by the ISO.

43.7.2 Minimum Load, Emissions and Start-Up Costs

43.7.2.1 Minimum Load Costs

Scheduling Coordinators representing resources designated under this Section 43 shall be eligible for recovery of Minimum Load Costs in the same manner that Scheduling Coordinators representing Resource Adequacy Resources included in Resource Adequacy Plans are eligible for the recovery of such costs under Sections 40.6B of the Tariff..

43.7.2.1.1 Allocation of Unrecovered Minimum Load Costs

Unrecovered Minimum Load Costs under Section 43.7.2.1 shall be allocated in accordance with Section 40.6B.5 of the ISO Tariff.

43.7.2.2 Emissions Costs

Scheduling Coordinators representing resources designated under this Section 43 shall be eligible for recovery of Emissions Costs in the same manner that Scheduling Coordinators representing Resource Adequacy Resources included in Resource Adequacy Plans are eligible for the recovery of such costs under Sections 40.11 of the ISO Tariff.

43.7.2.2.1 Recovery of Emissions Costs

The ISO will recover funds to pay Emissions Costs under Section 43.7.2.2 in accordance with Sections 40.11 of the ISO Tariff.

43.7.2.3 Start-Up Costs

Scheduling Coordinators representing resources designated under this Section 43 shall be eligible for recovery of Start-Up Costs in the same manner that Scheduling Coordinators representing Resource Adequacy Resources included in Resource Adequacy Plans are eligible for the recovery of such costs under Sections 40.12 of the ISO Tariff.

43.7.2.3.1 Recovery of Start-Up Costs

The ISO will recover funds to pay Start-Up Costs under Section 43.7.2.3 in accordance with Sections 40.12 of the ISO Tariff.

43.8 Allocation of RCST Capacity Payment Costs

For each month, the ISO shall allocate the costs of RCST Capacity Payments made pursuant to Section 43.7.1 as follows:

(1) <u>Annual System RCST Designations</u>: 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) <u>Monthly System RCST Designations</u>: If the ISO makes RCST designations under Section 43.3.2, then the ISO will allocate the total costs of RCST Capacity Payments for such

RCST designations (for the full term of those RCST designations) pro rata to each SC-RA Entity based on its portion of the aggregate Month-Ahead System Deficiency.

(3) Local RCST Designations for 2007.

[Reserved]

(4) Significant Event RCST Designations for 2006: If the ISO makes any Significant Event RCST designations under Section 43.4 during 2006, the ISO will allocate the costs of such designations to all SC-RA Entities in the TAC Area(s) in which the Significant Event caused or threatened to cause a failure to meet Applicable Reliability Criteria based on Scheduling Coordinators' RA Entity Load Share Percentage(s) in such TAC Area(s).

(5) Significant Event Designations for 2007.

[Reserved]

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.

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 service 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

ISO Website	The ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time.
ISP (Internet Service Provider)	An independent network service organization engaged by the ISO to establish, implement and operate WEnet.
Joint Powers Agreement	An agreement governing a Joint Powers Authority that is subject to the California Joint Exercise of Powers Act (California Government Code, Section 6500, *et seq.*).
Joint Powers Authority	An authority authorized by law through which two or more public entities jointly exercise their powers.
Large Generating Facility	A Generating Facility having a Generating Facility Capacity of more than 20 MW.
LARN Report for 2006	The report, published by the ISO, which identifies each Local Reliability Area for 2006 and 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.
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, including, e.g. a Scheduling Coordinator), including a load aggregator or power marketer; (i) serving End Users within the ISO Control Area and (ii) that has been granted 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 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 resources that are effective 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 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.
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 40.14 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 Output	The gross Energy output from a Generating Unit less the Station Power requirements for such Generating Unit during the Netting Period, or the Energy available to provide Remote Self-Supply from a generating facility in another Control Area during the Netting Period.
Netting Period	A calendar month, representing the interval over which the Net Output of one or more generating resources in a Station Power Portfolio is available to be attributed to the self-supply of Station Power in that Station Power Portfolio.
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 local area reliability needs of the ISO 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.
On-Site Self-Supply	Energy from a Generating Unit that is deemed to have self-supplied all or a portion of its associated Station Power load without use of the ISO Controlled Grid during the Netting Period.
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 load in a TAC Area. 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 by the total coincident peak Load of all RA Entities in the TAC Area in 2005.
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 carry out its functions.

Revised Estimated RMR Invoice	The monthly invoice issued by the RMR Owner to the ISO pursuant to the RMR Contract reflecting appropriate revisions to the Estimated RMR Invoice based on the ISO's validation of the Estimated RMR Invoice.
Revised Schedule	A Schedule submitted by a Scheduling Coordinator to the ISO following receipt of the ISO's Suggested Adjusted Schedule.
RMR Owner	The provider of services under a Reliability Must-Run Contract.
Real-Time Dispatch (RTD) Software	The security constrained optimal dispatch and ex post pricing software used by the ISO to determine which Ancillary Service and Supplementary Energy resources to Dispatch and to calculate the Ex Post Prices.
Rules of Conduct	The rules set forth in 37.2 through 37.7.
Sanction	A consequence specified in Section 37 for the violation of a Rule of Conduct, which may include a) a warning letter notifying the Market Participant of the violation and future consequences specified under Section 37 if the behavior is not corrected, or b) financial penalties. Neither referral to FERC nor rescission of payment for service not provided shall constitute a Sanction.
SCADA (Supervisory Control and Data Acquisition)	A computer system that allows an electric system operator to remotely monitor and control elements of an electric system.
SC-RA Entity	A Scheduling Coordinator for an RA Entity.
Scheduling Coordinator Agreement	An agreement between a Scheduling Coordinator and the ISO whereby the Scheduling Coordinator agrees to comply with all ISO rules, protocols and instructions, as those rules, protocols and instructions may be amended from time to time.
Scheduling Coordinator Applicant	An applicant for certification by the ISO as a Scheduling Coordinator.
Scheduling Coordinator Application Form	The form specified by the ISO from time to time in which a Scheduling Coordinator Applicant must apply to the ISO for certification as a Scheduling Coordinator.

Scheduling Coordinator Customer	A customer of the Scheduling Coordinator Applicant or a Scheduling Coordinator for whom the Scheduling Coordinator provides services relevant to the ISO Controlled Grid.
Scaled Marginal Loss Rate	A factor calculated by the ISO for a given Generator location for each hour by multiplying the Full Marginal Loss Rate for such Generator location by the Loss Scale Factor for the relevant hour.

	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.
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.
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.
Small Generating Facility	A Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

<u>Spinning Reserve</u>	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.
<u>Stand Alone Network Upgrades</u>	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.
<u>Standard Large Generator Interconnection Agreement (LGIA)</u>	The form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility.
<u>Standard Large Generator Interconnection</u>	The ISO Protocol that sets forth the interconnection procedures applicable to an Interconnection Request pertaining to a Large

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.
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.

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	0.756	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	September	October	November	December
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	0.576	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	1.254	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	1.336	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).

Attachment B – Blacklines

Reliability Capacity Services Tariff Settlement Filing

Docket EL05-146-000

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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, ~~and that comply with such notice requirements, if any, as may be imposed by FERC for a particular period of time,~~ 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.

* * *

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 ~~and that comply with such notice requirements, if any, as may be imposed by FERC for a particular period of time~~ 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~~40.14 during that month, (ii) the total Imbalance Energy payments received when that Generating Unit is running at minimum load, and (iii) the Frequently Mitigated Adder under Section 34.1.2.1.1 during the calendar month, exceeds the Qualifying Capacity times the maximum Monthly RCST Charge (established in Schedule 6 of Appendix F) reduced by the Monthly PER (established in Schedule 6 of Appendix F), the FERC Must-Offer Generator shall not be eligible to receive Must-Offer Capacity Payments or the Frequently Mitigated Adder under Section 34.1.2.1.1 for that Generating Unit for that Trading Day, nor for any other Trading Day in the remainder of the calendar month (but shall continue to recover Minimum Load Costs and imbalance Energy payments). This Section 40.14 shall expire at midnight on the earlier of December 31, 2007 or the date immediately before the MRTU goes into effect.

* * *

43.5 Obligations of a Resource Designated under the RCST

43.5.1 Must-Offer Obligations

Generating Units designated under the RCST shall be subject to all of the availability, must-offer, dispatch, testing, reporting, and verification obligations applicable to Resource Adequacy Resources identified in Resource Adequacy Plans under Section 40.6A of the ISO Tariff. Generating Units designated under the RCST must offer ~~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 Services markets to the extent capable.

* * *

Appendix A

Must-Offer Capacity Payment	The payment made in accordance with Section ~~43.9~~ 40.14 of this ISO Tariff.

* * *

SC-RA Entity	A Scheduling Coordinator for an RA Entity.

* * *

Attachment C – Clean Sheets

Corrections to October 20 RCST Compliance Filing Sheets Reflecting Low-Voltage TRR Tariff Amendment

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 local area reliability needs of the ISO 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-Load-Serving Participating TO	A Participating TO that (1) is not a UDC, MSS Operator or Scheduling Coordinator serving End-Use Customers and (2) does not have Gross Load in accordance with Section 9 of Schedule 3 of Appendix F.
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.
On-Site Self-Supply	Energy from a Generating Unit that is deemed to have self-supplied all or a portion of its associated Station Power load without use of the ISO Controlled Grid during the Netting Period.
Operating Reserve	The combination of Spinning and Non-Spinning Reserve required to meet WECC and NERC requirements for reliable

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all of the persons listed on the official service list for the captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Folsom, California this 15th day of March, 2007.

Anthony J. Ivancovich / BRM

Anthony J. Ivancovich