California ISO
Your Link to Power

California Independent
System Operator Corporation

June 12, 2006

Ms. Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation, Docket No. ER06-723-____
The Interim Reliability Requirements Program

Dear Secretary Salas:

In compliance with the Federal Energy Regulatory Commission's ("Commission" or "FERC") May 12, 2006 "Order Accepting Tariff Revisions, as Modified," 115 FERC ¶ 61,172 (2006) ("May 12 Order"), the California Independent System Operator Corporation ("CAISO") hereby submits six copies of its revised Interim Reliability Requirements Program ("IRRP") for Commission approval and inclusion in the CAISO Tariff.[1] The CAISO is also tendering two additional copies to be time and date stamped and returned to our courier.

I. Background

On March 13, 2006, the CAISO filed proposed revisions to its Tariff to implement the IRRP. The background and fundamental objectives underlying the CAISO's development of the IRRP were detailed in the transmittal letter that accompanied the March 13 IRRP Tariff filing. The CAISO, therefore, will not repeat that background here. Generally, the IRRP adjusts the CAISO's existing operations to incorporate resource adequacy programs developed by the California Public Utilities Commission ("CPUC") and other Local Regulatory Authorities ("LRAs") in accordance with state mandates. The IRRP is intended to be effective until implementation of the CAISO's Market Redesign and Technology Upgrade ("MRTU") project.

The IRRP, among other things:

- Requires Load Serving Entities ("LSEs") and resource suppliers through their respective Scheduling Coordinators to provide information demonstrating compliance with resource adequacy requirements imposed by the CPUC or LRA, as applicable.
- Revises the current Commission-approved Must-Offer Waiver Denial ("MOWD") process to establish a commitment priority for identified resource adequacy resources.

[1] Capitalized terms that are not otherwise defined are defined in the Master Definitions Supplement, Appendix A to the CAISO Tariff.

- Modifies the Minimum Load Cost Compensation for resource adequacy resources committed pursuant to a MOWD in recognition of the opportunity of those resources to receive revenue under bilaterally negotiated resource adequacy arrangements.
- Establishes "deliverability" tests for internal and imported resource adequacy resources.

The Commission accepted the IRRP Tariff revisions, with modifications, in the May 12 Order. The May 12 Order required the CAISO to make a compliance filing within thirty (30) days of the date of the order. This filing complies with that directive.

II. Contents of Filing

This filing comprises:

This Transmittal Letter	
Attachment A	IRRP Tariff Language Blacklined Against IRRP filed on March 13, 2006 (based on the version of the S&R Tariff filed on September 21, 2005)
Attachment B	IRRP Clean Tariff sheets incorporating changes shown in Attachment A but based on the March 22, 2006 S&R Tariff
Attachment C	Clean Tariff Sheets incorporating the entire IRRP, as modified by the May 12 Order, and conforming to the March 22, 2006 S&R Tariff

III. Communications

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IV. Specific Changes to the IRRP in Response to the May 12 Order

As noted above, the Commission required a number of modifications to the IRRP in the May 12 Order. These revisions are shown in blackline against the IRRP filed on March 13, 2006, in Attachment A. A discussion of these revisions to the IRRP follows in the sequence discussed in the May 12 Order.

1. Modifications to Permit Acceptance of Resource Adequacy Program Elements Pending LRA Approval (Sections 40.4 and 40.5.1)

The IRRP explicitly defers to state and local regulators with regard to various elements of any resource adequacy program, including Demand Forecast methodology (§ 40.3), Planning Reserve

Margin (§40.4), and the criteria for determining Qualifying Capacity (§40.5.1). However, the IRRP also includes default criteria for Planning Reserve Margins and Qualifying Capacity should state and local regulators not adopt these resource adequacy program elements. The May 12 Order found that the IRRP's use of default criteria did not interfere with the resource adequacy programs of the CPUC and other LRAs.[2] The May 12 Order further approved the CAISO's proposal to accept resource adequacy program elements from LSEs pending approval from their regulators in order to avoid the unnecessary application of default criteria and directed the CAISO to make the necessary tariff modifications to reflect this flexibility.[3]

The May 12 Order's direction to modify the Tariff referred only to Section 40.4, which addresses Planning Reserve Margins. As noted above, default criteria also exist for Qualifying Capacity under Section 40.5.1. The CAISO believes the Commission's rationale, and the CAISO's proposal to accept LSE program elements for an interim period, applies equally to Section 40.5.1. Accordingly both Sections 40.4 and 40.5.1 have been modified. Moreover, rather than allow the review of LSE program elements to remain pending indefinitely, the CAISO has set forth a requirement that such elements be adopted by the LRA by August 31, 2006, for inclusion in the October 2006 Resource Adequacy Plan showing. This allows the LSE program elements to remain effective through the September 2006 reporting month. The CAISO believes this provides LRAs with a reasonable time to consider and approve resource adequacy program elements.

2. Metered Subsystem Reporting Obligations (Sections 40.2.1, 40.2.2, and 40.6)

In its answer to protests, the CAISO proposed explicit revisions to Sections 40.2.1, 40.2.2, and 40.6 of the IRRP to utilize existing reporting requirements under Metered Subsystem ("MSS") agreements to obtain equivalent resource information from LSEs subject to MSS agreements. The May 12 Order accepted the CAISO's proposed revisions. Those revisions are reflected in the Tariff sections provided herein.

3. Additional Modification to Annual Resource Adequacy Plan Reporting

The CAISO has included in Section 40.2.1 a modification not required by the May 12 Order, but necessary to ensure consistency between CPUC and non-CPUC jurisdictional entities. The version of Section 40.2.1 submitted on March 13, 2006, included September 30 as the date non-CPUC jurisdictional entities are required to submit annual Resource Adequacy Plans. This date was selected to establish consistency in reporting obligations between non-CPUC jurisdictional LSEs and CPUC LSEs, given that the CPUC has adopted September 30 as the date for submission of annual Resource Adequacy Plans. The CPUC has issued a proposed decision that would extend the date for submission of the annual Resource Adequacy Plan for LSEs under its jurisdiction to October 25, 2006. The CAISO supports this proposed modification as a means to potentially reduce the CAISO's need for procuring Reliability Must Run ("RMR") generation by creating better coordination between LSE procurement of local capacity resources and the CAISO's RMR designation process. Accordingly, the CAISO has modified Section 40.2.1 to also extend the reporting date for non-CPUC jurisdictional entities in a manner that would provide uniformity of treatment between CPUC and non-CPUC jurisdictional LSEs.

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[2] May 12 Order at P 28.

[3] *Id.* at P 40.

4. De Minimus LSEs (Section 40.2.2)

In response to the IRRP, Williams noted that it acts as the Scheduling Coordinator for a tank farm, located on the site of one of its generating facilities, with "de minimis" load and that it is unnecessary to apply the full range of reporting requirements of such a Scheduling Coordinator. [4] The May 12 Order agreed and ordered that "an LSE with *de minimis* load should be allowed to submit an annual resource adequacy plan and request that the annual plan also constitute its monthly resource adequacy plan for each month of the year." The CAISO has established the threshold for "*de minimis*" Load as an annual peak of less than one (1) MW. For such a Load Serving Entity, the Scheduling Coordinator may notify the CAISO that its annual Resource Adequacy Plan under Section 40.2.1 will also constitute the monthly Resource Adequacy Plan under Section 40.2.2 for the upcoming compliance year.

5. Notification of Dispute or Discrepancy (Section 40.2.3)

The May 12 Order directed "the CAISO to modify section 40.2.3 to require the CAISO to notify LSEs within 10 business days of the submission of their resource adequacy plans if a discrepancy or deficiency exists in the LSEs' plans."[5] The CAISO has modified section 40.2.3 consistent with this directive.

6. Demand Forecasts (Section 40.3)

The May 12 Order stated:

> Given the interim nature of the IRRP, and the fact that the guidelines for CPUC load forecasts are understood, the CAISO is willing to accept SoCal Edison's proposed modification. In addition, the CAISO agrees with PG&E that section 40.3 incorrectly limits itself to the monthly resource adequacy plans and should include annual plans as well.[6]

The May 12 Order went on to "accept the changes proposed by SoCal Edison and PG&E and agreed to by the CAISO and direct[ed] the CAISO to submit revised tariff language reflecting those changes."[7] Accordingly, the CAISO has revised Section 40.3 to include reference to annual plans and the verbatim change set forth in SCE's intervention and comments to the IRRP.[8]

7. Deliverability Analysis

With respect to the CAISO's assessment of a Generating Unit's ability to deliver its output to the aggregate of ISO Control Area Load pursuant to Section 40.5.2.1, the May 12 Order required three modifications. First, the May 12 Order accepted the CAISO's proposal "to conduct a deliverability analysis on an annual basis and apply the results to subsequent resource adequacy compliance years" and directed the CAISO to so specify. Intervenors recognized, and the CAISO agreed, that implicit in

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4 *Id.* at P 54.

5 *Id.* at P 69.

6 *Id.* at P 72.

7 *Id.* at P 73.

8 Motion to Intervene and Comments of Southern California Edison Company on California Independent System Operator Corporation's Tariff Filing to Establish Interim Reliability Requirements Program, *California Independent System Operator Corporation*, Docket No. ER06-723-000 (April 3, 2006) ("SCE Comments") at p. 4.

the CAISO's annual study approach and its intent to modify Net Qualifying Capacity of a resource only for prospective compliance periods is the fact that the effect of the deliverability analysis on Generating Units would remain fixed for a period of time. Therefore, the May 12 Order required the IRRP to clearly set forth the period for which Net Qualifying Capacity would remain stable. [9] The CAISO has done this by explicitly stating that the results of the CAISO's 2006 deliverability analysis would apply throughout compliance year 2007. It is possible that the CAISO's deliverability analysis will result in an assessment of a Generating Unit's deliverability that will apply for a period longer than the next IRRP compliance year. However, given the interim nature of the IRRP as a transitional Tariff effective only until implementation of MRTU, the CAISO believes it is appropriate to limit the scope of Section 40.5.2.1 to 2007 only. Any further discussion regarding application of the CAISO's deliverability analysis beyond 2007 should take place in the context of the pending Commission proceeding to evaluate the MRTU proposal.[10] The CAISO has also specified that the deliverability analysis will be conducted in a manner and under a time frame that allows the results to be incorporated into the annual and monthly Resource Adequacy Plans.

The second and third modifications required by the Commission are related. The May 12 Order directed the "CAISO to modify proposed tariff section 40.5.2.1 to eliminate the apparent duty to prevent degradation of an existing unit's deliverability" and "clarify that the interconnection process is governed by section 25 of the tariff."[11] The CAISO has accomplished both of these instructions by deleting the last sentence of the previously proposed Section 40.5.2.1. This eliminates reference to preventing the "degradation" of the deliverability of existing units and removes any reference to interconnection in the IRRP. As such, the IRRP can no longer be read to conflict or otherwise affect the other Commission-approved Tariff provisions governing interconnection.

8. Import Allocation Methodology (Section 40.5.2.2)

The May 12 Order found "the CAISO's proposal for allocation of import capacity in 2007 to be equitable and we accept it." However, the May 12 Order is not explicit as to which import allocation proposal for 2007 was accepted – the CAISO's proposal as filed on March 13, 2006 or as expressed in the CAISO's answer to protests and comments. Because the May 12 Order directed "the CAISO to submit revised tariff sheets reflecting the *new* import allocation methodology," the CAISO interprets the May 12 Order as requiring Section 40.5.2.2 to be modified in accordance with the CAISO's answer.[12] In this regard, the May 12 Order characterized the CAISO's answer as agreeing to:

> revise the accounting or allocation of import capability for 2007 so that both CPUC-jurisdictional and non-CPUC jurisdictional LSEs are permitted to receive resource adequacy import allocation for their existing resource agreements (as of March 10, 2006), with any remaining import capacity allocated to both CPUC and non-CPUC LSEs based on an LSEs load share to the CAISO control area peak load.[13]

The CAISO has revised Section 40.5.2.2 to capture the Commission's instructions to first allocate import capacity by honoring, to the maximum extent possible, resource commitments and then distributing remaining import capacity among both CPUC and non-CPUC jurisdictional entities in a uniformly applicable manner using load share ratios. Under revised Section 40.5.2.2's multi-step

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9 May 12 Order at P 84.

10 *California Independent System Operator Corporation*, FERC Docket No. ER06-615-000.

11 May 12 Order at P 84.

12 *Id.* at P 96.

13 *Id.* at P 94.

process, the CAISO initially reserves from the total available import capacity, capacity associated with Existing Contracts (transmission contracts) and other transmission ownership rights. The CAISO next seeks to accommodate existing resource commitments entered into prior to March 10, 2006 by allowing all LSEs to identify those existing import resources and assign those resources to specific branch groups. These existing resource commitments will be honored, except where insufficient capacity exists on a particular branch group to accommodate all requests. In that case, the CAISO will allocate the requested resource commitment MW quantities based on the "Import Capacity Load Share" ratio of each LSE submitting such resource commitments on that branch group. Import Capacity Load Share is each LSE's proportionate share of the forecasted 2007 coincident peak Load for the ISO Control Area, as determined by the California Energy Commission (defined as "Coincident Load Share"), relative to the total Coincident Load Share of those LSEs that have requested capacity on that particular branch group. To the extent this allocation does not fully assign the total import capacity for that branch group to the requested existing resource commitments, the remaining capacity will continue to be allocated in the same manner to those LSEs whose submitted requests were not fully satisfied for that branch group through an initial application of the formula. An example of this allocation methodology is provided below.

Import Capacity Load Share Method						
Branch Group Limit	1000		Round 1		Round 2	
	Requested Branch Group Capacity	Coincident Load Share	Import Capacity Load Share (Rd.1)	Allocate capacity based on Load Ratio Share	Import Capacity Load Share (Rd.2)	Allocate capacity based on Load Ratio Share
Entity 1	600	70%	82%	600.0		600.00
Entity 2	0	15%	0%	0.0		0.00
Entity 3	500	10%	12%	117.6	67%	266.67
Entity 4	200	5%	6%	58.8	33%	133.33
Total	1300	100%	100%	776.5	100%	1000
Over-Request	300			223.5		0

Following this step, to the extent capacity remains available on particular branch groups, that capacity will be aggregated and allocated to all LSEs based on their respective Coincident Load Shares. Information on the quantity and location of available capacity will be disseminated by the CAISO. LSEs are provided an opportunity to trade this allocation not only to other LSEs, but also to any Market Participant. The inclusion of other Market Participants is consistent with the CPUC's determination regarding the identity of entities that may participate in trading import capacity for resource adequacy purposes.[14] LSEs and other Market Participants then notify the CAISO where they want their import capacity assigned. Again, to the extent a branch group is over requested, the CAISO will apply the Import Capacity Load Share methodology. Market Participants without a Coincident Load Share will be given a Coincident Load Share equal to the average of the LSEs from which they received their capacity share(s). The CAISO will provide entities with two iterative opportunities to request remaining available import capacity.

[14] *Opinion of Petition of Pacific Gas and Electric Company for Modification of Decision 05-10-042*, CPUC Decision 06-02-007 (Feb. 16, 2006).

The May 12 Order also requested that the CAISO delete reference to a 2006 import allocation process. The CAISO has done so. In addition, the May 12 Order indicated that the CAISO should complete its annual import allocations no later than July 1. The CAISO will complete its determination of total import capacity by July 1, 2006. However, the CAISO's ability to complete the allocation process is, in part, contingent upon coincident load share information received from the California Energy Commission. It is anticipated that this information will be provided by July 1, but this will result in the iteration process described above being completed subsequent to July 1. Given this fact, the CAISO has indicated that the iterations will be completed according to the schedule set forth in CAISO market notices.

9. Available Generation (Sections 40.6A.2 and 40.6A.4)

A. Intermittent Resources

The May 12 Order disagreed with intervenors that wind resources that have scheduled in accordance with the CAISO's Participating Intermittent Resource Program ("PIRP") should be excluded from the definition of "available generation." However, the May 12 Order found that the CAISO should clarify the relationship between available generation and the obligation to offer under Section 40.6A.4 with respect to PIRP resources.[15] The CAISO has complied with this request by specifying in Section 40.6A.4 that a PIRP resource satisfies its offer obligation by scheduling in accordance with the ISO Tariff provisions governing PIRP. PIRP is, therefore, the mechanism by which wind resources participating in PIRP offer to the CAISO their "available generation," which, at any given moment, may be more or less than its final Hour-Ahead Scheduling depending on wind conditions among other things.

B. System Resources

The May 12 Order agreed "with Powerex that system resources have different characteristics than individual generating units and direct[ed] the CAISO to incorporate Powerex's proposed language in the tariff."[16] In compliance with this directive, the CAISO has incorporated Powerex's suggested revisions into Section 40.6A.2.[17]

10. Reporting Requirements for Non-Participating Generators (Section 40.6A.3)

The May 12 Order found that "the information reporting requirement in section 40.6A.3 is not applicable to non-resource specific system resources and to Qualifying Facilities that are not participating generators, but have power purchase agreements with a host utility." The CAISO was directed to make this clarification in its compliance filing.

The CAISO has done so by expressly excluding from the scope of Section 40.6A.3 "non-resource specific System Resources" as well as "Qualifying Facilities with effective contracts under the Public Utilities Regulatory Policies Act" that are not Participating Generators. The CAISO believes that its use of the term PURPA contract to represent the May 12 Order's reference to "power purchase contracts with a host utility" is consistent with the Commission's intent. The purpose of Section 40.6A.3 is to obtain information necessary to determine available generation and to efficiently dispatch

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15 May 12 Order at P 103.

16 *Id.*

17 Motion to Intervene and Protest of Powerex Corp., *California Independent System Operator Corporation*, Docket No. ER06-723-000 (April 3, 2006) ("Powerex Comments") at p. 6.

Resource Adequacy Resources. Consistent with this objective, Section 40.6A.3 seeks, among other data, the Generating Unit's minimum and maximum operating levels and ramp rates. An exemption from this reporting requirement for Qualifying Facilities that cannot be dispatched because of the "must-take" characteristic of a PURPA contract is appropriate. The same rationale does not extend indiscriminately to all power purchase contracts, which may contain differing provisions regarding the host utility's ability to control the output of the Generating Unit. Indeed, the CAISO's use of the more focused term aligns with the direction expressed in Section 1253 of the Energy Policy Act of 2005, which anticipates a world that does not presume that all power purchase contracts between Qualifying Facilities and public utilities are subject to the PURPA mandatory purchase requirement.[18]

11. Submission of Bids and Penalties for Non-Compliance (Sections 40.6A.5 and 40.6A.7)

In its comments in response to the IRRP, SCE noted that the offer obligation associated with Resource Adequacy Resources should be on the Scheduling Coordinator for the resource because that is the entity upon which the CAISO has a relationship. A corollary to this observation is that the sanctions associated with a violation of the offer obligation imposed on Resource Adequacy Resources should also be directed to the resource's Scheduling Coordinator. The CAISO and the May 12 Order agreed that SCE's proposed clarifications in this regard should be incorporated into the IRRP.[19] Accordingly, Sections 40.6A.5 and 40.6A.7 have been modified based on SCE's proposed revisions.[20]

12. Dynamically and Non-Dynamically Scheduled System Resources (Section 40.13.12.2)

The May 12 Order found that "[s]ince there is no apparent reason for different provisions for dynamically and non-dynamically scheduled resources, we direct the CAISO to incorporate Powerex's proposed modifications in the tariff."[21] Powerex's proposed changes have been incorporated into the CAISO's compliance filing.[22]

13. Confidentiality (Sections 20.2 and 20.4)

The May 12 Order found that "market sensitive data submissions such as annual and monthly resource adequacy plans should be afforded confidential treatment."[23] In addition, Constellation had raised a concern that LSEs without a direct contractual relationship with the CAISO needed assurance that information provided to facilitate resolution of potential disputes over capacity commitments will remain confidential. The May 12 Order agreed and directed the CAISO to include such a provision in its compliance filing."[24]

The CAISO has addressed these confidentiality concerns in a comprehensive manner by modifying the relevant general confidentiality provisions of its Tariff found at Sections 20 et seq. The CAISO believes it is more effective for Tariff provisions relating to confidentiality to be incorporated in a

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18 16 U.S.C. § 824a-3.
19 May 12 Order at P 121.
20 SCE Comments at 7-8.
21 May 12 Order at P 135.
22 Powerex Comments at 8.
23 May 12 Order at 138.
24 *Id.*

single location and, therefore, has deleted references to confidentiality in Sections 40.5.2.2 relating to import allocation and 40.6 relating to Supply Plans as redundant. Specifically, the CAISO has modified Section 20.2 by adding a new paragraph assigning confidential treatment to information provided by both Scheduling Coordinators and other Market Participants under the IRRP, as required by the Commission. By broadening Section 20.2 to include entities other than Market Participants, the CAISO has addressed Constellation's concern regarding the lack of contractual privity of non-Scheduling Coordinators. This paragraph further lists each type or source of confidential information, including data contained in monthly and annual resource adequacy plans (§ 40.2.1, 40.2.2) or supply plans (§ 40.6), demand forecasts (§ 40.3), information on import contracts received for import allocation purposes (§40.5.2.2), Generating Unit operating information provided by non-Participating Generators (§§ 40.6A.3, 40.7.3), and information received through the dispute resolution process (§40.2.3). However, consistent with the May 12 Order, that section specifies that programmatic Planning Reserve Margin and Qualifying Capacity eligibility criteria are not considered confidential.

Further, the CAISO noted that information received pursuant to the IRRP may need to be communicated to the CPUC or LRA for enforcement purposes. Under the IRRP, any penalties for the failure of an LSE to comply with a resource adequacy program are to be administered by the CPUC or LRA for the LSE as appropriate. It is also axiomatic that to effectuate the informal dispute resolution provisions contained in Section 40.2.3, the CAISO must disclose sufficient information to allow the involved Scheduling Coordinators or Market Participants to pursue remedial action or engage in informal dispute resolution discussions. To permit these activities, notwithstanding the confidential nature of IRRP information, the CAISO has modified Section 20.4 by authorizing the CAISO to disclose information to the CPUC or relevant LRA for compliance purposes as well as to the specific Scheduling Coordinators and/or Market Participants involved in a dispute or discrepancy, but only "to the extent that the information identifies the disputed transaction and relevant counterparty or counterparties." Thus, the CAISO's disclosure provisions are narrowly tailored to allow dissemination of information only to permit the initiation of communication between parties to a dispute.

V. Description of Attachment C

On March 13, 2006, the CAISO filed the proposed IRRP Tariff language based on the Simplified and Reorganized ("S&R") Tariff filed September 21, 2005 in Docket No. ER05-1501 and approved in the Commission's February 24 Order in that Docket,[25] effective as of March 1, 2006. The CAISO re-filed the entire S&R Tariff on March 22, 2006 as a "Third Replacement" version of the CAISO Tariff, incorporating changes contained in the CAISO's January 13 post-technical conference Comments in that Docket, as well as additional tariff language that had been accepted by the Commission in various proceedings between the September 21 filing of the S&R Tariff and its March 1 effective date. Consequently, the tariff sheets were renumbered. Attachment B to this letter reflects the changes ordered by the Commission in the May 12 Order, as reflected on the March 22, 2006 version of the S&R Tariff. Attachment C reflects the entire IRRP as filed and modified by the Commission and is being provided to show the sheet number changes made in the March 22, 2006 S&R Tariff. The CAISO would like to note the following changes made to these sheets in order to reflect tariff changes accepted by the Commission since the March 13 filing: (1) Sheet No. 232 contains Section 11.2.16 Emissions and Start-Up Fuel Cost Charges, which appeared as Section 11.2.13 in the IRRP filing; (2) Sheets 495A and 536 contain language approved in the Commission's May 12 Order

[25] "Order Approving Tariff Revisions," *California Independent System Operator Corporation*, 114 FERC ¶ 61,199 (Feb. 24, 2006) ("February 24 Order").

for the Credit Policy Filing in Docket No. ER06-700; and (3) Sheets 514, 514A, 524 and 524A contain language accepted in the Commission's March 31 Order for the Station Power Compliance Filing in Docket No. ER05-849.

VI. Conclusion

For the reasons set forth above, the CAISO respectfully requests that the Commission accept the IRRP Tariff provisions as revised in accordance with the Commission's May 12 Order.

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ATTACHMENT A

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20 CONFIDENTIALITY.

20.2 Confidential Information.

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

(a) individual bids for Supplemental Energy;

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

(c) individual bids for Ancillary Services;

(d) transactions between Scheduling Coordinators;

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

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

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

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

<u>(b) Demand Forecast and other hourly data provided pursuant to Section 40.3.</u>

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

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

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

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20.4 Disclosure.

Notwithstanding anything in this Section 20 to the contrary,

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

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

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

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

(ii) In order to maintain reliable operation of the ISO Control Area, the ISO may share critical operating information, system models, and planning data with other WECC Reliability Coordinators, who have executed the Western Electricity Coordinating Council Confidentiality Agreement for Electric System Data, or are subject to similar confidentiality requirements; or

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

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

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

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

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40.2 Submission of Annual and Monthly Resource Adequacy Plan.

40.2.1 Annual Resource Adequacy Plan.

Each Scheduling Coordinator for a Load Serving Entity serving Load within the ISO Control Area must provide the ISO with an annual Resource Adequacy Plan; however, Scheduling Coordinators representing a Load Serving Entity with an MSS Agreement shall submit the information required by this section pursuant to the terms and formal standards set forth in the MSS Agreement. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted on the schedule and in the form approved by the CPUC. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area, except Load Serving Entities with an MSS Agreement, shall be submitted no later than ~~September 30th~~ October 25th of each year and in the form set forth on the ISO Website. Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities should be identical. The annual Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin under Section 40.4, or portion thereof as established by the CPUC or applicable Local Regulatory Authority, and must apply the Net Qualifying Capacity requirements of Section 40.5.2.

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40.2.2 Monthly Resource Adequacy Plan.

Each Scheduling Coordinator for a Load Serving Entity serving Load within the ISO Control Area must provide the ISO with a monthly Resource Adequacy Plan; however, (1) Scheduling Coordinators representing a Load Serving Entity with an MSS Agreement shall submit the information required by this section pursuant to the terms and formal standards set forth in the MSS Agreement and (2) Scheduling Coordinators for a Load Serving Entity serving Load within the ISO Control Area in a forecasted peak amount of less than (1) MW on average per day over the compliance year may notify the ISO that the Load Serving Entity's annual Resource Adequacy Plan pursuant to Section 40.2.1 will constitute its monthly Resource Adequacy Plan under this section for each month of the following compliance year. The monthly Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted on the schedule and in the form approved by the CPUC. The monthly Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area, except for Load Serving Entities with an MSS Agreement, shall be submitted no later than on the last business day of the second month prior to the compliance month (e.g., March 31 for May) and in the form set forth on the ISO's Website. Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities should be identical. The monthly Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin under Section 40.4 for the relevant reporting month and must apply the Net Qualifying Capacity requirements of Section 40.5.2.

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40.2.3 Resource Adequacy Plan Compliance.

The ISO will evaluate whether each monthly Resource Adequacy Plan submitted by a Scheduling Coordinator on behalf of a Load Serving Entity serving Load within the ISO Control Area satisfies the Load Serving Entity's obligation to procure sufficient Net Qualifying Capacity to comply with its Planning Reserve Margin under Section 40.4. If a Scheduling Coordinator for a Load Serving Entity submits a Resource Adequacy Plan that the ISO identifies as not demonstrating compliance with Resource Adequacy rules adopted by the CPUC or other Local Regulatory Authority, as applicable, the ISO will, within 10 business days, first notify the relevant Scheduling Coordinator, or in the case of a mismatch between Resource Adequacy Plan(s) and Supply Plan(s), the relevant Scheduling Coordinators~~,~~ in ~~and~~ attempt to resolve the issue. If this process does not resolve the ISO's concern, the ISO will notify the CPUC or other appropriate Local Regulatory Authority of the potential deficiency. To the extent that the CPUC or other appropriate Local Regulatory Authority allows Load Serving Entities under its jurisdiction to cure the identified deficiency or determines that no deficiency exists, the Scheduling Coordinator shall inform the ISO at least 10 days before the effective month. If the deficiency is not resolved prior to the 10th day before the effective month, the ISO will use the information contained in the Supply Plan to set Resource Adequacy Resources' obligations under this section of the ISO Tariff for the applicable reporting month.

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40.3 Demand Forecasts.

The annual and monthly Resource Adequacy Plans must include a Demand Forecast as follows:

a. For CPUC Load Serving Entities, the Demand Forecast shall be the Demand Forecast required by the CPUC. To the extent the ISO has not received a CPUC Load Serving Entity's load forecast through the CPUC's Resource Adequacy process, the Scheduling Coordinators for the CPUC Load Serving Entities must provide to the ISO a copy of the Demand Forecast that they provided to the CPUC and CEC, subject to the confidentiality terms established by the CPUC in its proceeding. ~~data and/or supporting information, as requested by the ISO, for the Demand~~

~~Forecasts required by this Section for each represented CPUC Load Serving Entity.~~

b. For non-CPUC Load Serving Entities, the Demand Forecast shall be the Demand Forecast required by the applicable Local Regulatory Authority. Scheduling Coordinators for non-CPUC Load Serving Entities must provide data and/or supporting information, as requested by the ISO, for the Demand Forecasts required by this Section for each represented non-CPUC Load Serving Entity.

c. If the CPUC or other Local Regulatory Authority has not established a requirement to prepare a Demand Forecast, the Scheduling Coordinator for the Load Serving Entity shall prepare and provide the ISO with a Demand Forecast that shall be the Load Serving Entity's monthly non-coincident peak Demand Forecast for its Service Area, for its MSS area, or in each Service Area of an Original Participating TO in which the Load Serving Entity serves Load, unless the Load Serving Entity agrees to utilize a coincident peak determination provided by the California Energy Commission for such Load Serving Entity. Scheduling Coordinators for Load Serving Entities covered by this subsection must provide data and/or supporting information, as requested by the ISO, for the Demand Forecasts required by this Section for each represented Load Serving Entity.

For Load Serving Entities that are local publicly owned electric utilities as defined in Section 9604 of the PUC, the Demand Forecasts required by this Section 40.3 should be consistent with Section 9620(a) of the PUC, as it may be amended from time to time, requiring that such Load Serving Entities meet their Planning Reserve Margin, peak demand, and operating reserves.

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40.4 Planning Reserve Margin.

The monthly Resource Adequacy Plan must include a level of Resource Adequacy Capacity sufficient to meet 100% of the Demand Forecast in Section 40.3 plus a Planning Reserve Margin as follows:

a. For Scheduling Coordinators representing CPUC Load Serving Entities, the Planning Reserve Margin shall be that adopted by the CPUC.

b. For Scheduling Coordinators representing non-CPUC Load Serving Entities, the Planning Reserve Margin shall be that adopted by the appropriate Local Regulatory Authority.

c. For Scheduling Coordinators representing Load Serving Entities for which the CPUC or other Local Regulatory Authority has not established a Planning Reserve Margin as of May 31, 2006, the Planning Reserve Margin shall be: (1) for compliance months June through September 2006, the Planning Reserve Margin provided by the Load Serving Entity to accommodate any processes to approve the Planning Reserve Margin that may be pending before the applicable Local Regulatory Authority and (2) thereafter, no less than 115% of the peak hour of the month in the Demand Forecast set forth in Section 40.3.

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40.5.1 Qualifying Capacity.

Qualifying Capacity is the capacity from a resource prior to application of the Net Capacity provisions of Section 40.5.2. The criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO. For compliance months June through September 2006, the criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types may be provided by the Load Serving Entity to accommodate any processes to approve the Qualifying Capacity criteria that may be pending before the applicable Local Regulatory Authority. Only if such criteria are not provided by the CPUC or other Local Regulatory Authority by August 31, 2006 for compliance month October 2006, then Section 40.13 will apply. The ISO shall use the criteria provided by the CPUC, other Local Regulatory Authority or, if necessary, Section 40.13, to determine and verify, if necessary, the Qualifying Capacity of all resources listed in a Resource Adequacy Plan; however, to the extent a resource is listed by one or more Scheduling Coordinators in their respective Resource Adequacy Plans, which apply the criteria of more than one regulatory entity that leads to conflicting Qualifying Capacity values for that resource, the ISO will apply the respective Qualifying

Capacity formulas applicable for each Load Serving Entity.

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40.5.2 Net Qualifying Capacity.

40.5.2.1 Deliverability Within the ISO Control Area.

In order to determine Net Qualifying Capacity from a Generating Unit, the ISO will determine that the Generating Unit is able to serve the aggregate of Load by means of a deliverability analysis. The deliverability analysis will be performed annually and shall focus on peak Demand conditions. The ISO will review its input assumptions and draft results with Market Participants before completing its determination. ~~The ISO will update the deliverability baseline analysis on an annual basis.~~ The ISO will coordinate with the CPUC and other Local Regulatory Authorities so that the results of the deliverability analysis can be incorporated~~utilized~~ in annual and monthly ~~the development of~~ Resource Adequacy Plans. The results of the ISO's 2006 deliverability analysis shall be effective for a period no shorter than compliance year 2007. To the extent the deliverability analysis shows that the Qualifying Capacity of a Generating Unit is not deliverable to the aggregate of Load under the conditions studied, the Qualifying Capacity of the Generating Unit will be reduced on a MW basis for the capacity that is undeliverable. ~~The ISO will utilize its interconnection process and procedures under Section 25 of the ISO Tariff to prevent degradation of the deliverability of an existing Generating Unit that could result from the interconnection of additional Generation.~~

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40.5.2.2 Deliverability of Imports.

This Section 40.5.2.2 shall apply only to Resource Adequacy Plans covering the period through December 31, 2007, unless superseded earlier by alternative ISO Tariff provisions. ~~The ISO shall establish for 2006 for each branch group the total import capacity values to be allocated to Load Serving Entities serving Load in the ISO Control Area for Resource Adequacy planning purposes, and will update those values for 2007. The updated import capacity values shall be posted on the ISO Website.~~ Total import capacity will be assigned to Load Serving Entities serving Load in the ISO Control Area and other Market Participants, if applicable, for 2007 as described by the following sequence of steps.

1. Step 1: The ISO shall establish for 2007 for each branch group the total import capacity values for the ISO Control Area, and will post those values on the ISO Website by July 1, 2006.

2. Step 2: For each branch group, the total capacity established in Step 1 will be reduced by subtracting the ~~I~~import capacity associated with (i) Existing Transmission ~~Contracts~~ and (ii) ~~E~~encumbrances and ~~T~~transmission ~~O~~ownership ~~R~~rights. Existing Contracts and encumbrances and transmission ownership rights therefore shall be reserved for holders of such commitments as part of the deliverability study and will not be subject to allocation under this Section. ~~For the purpose of accounting for import Resource Adequacy Capacity, the import capability of the system will be allocated by branch group by the ISO (1) to non-CPUC Load Serving Entities individually and (2) to the CPUC Load Serving Entities as an aggregated allocation, which will be subject to the allocation rules of the CPUC.~~

3. Step 3: From the amount of import capacity remaining on each branch group determined in Step 2 above, Load Serving Entities serving Load within the ISO Control Area will receive, to the extent feasible, an allocation on a particular branch group selected by the Load Serving Entity equal to each entity's resource commitments from outside the ISO Control Area, as of March 10, 2006, the terms of which runs through at least calendar year 2007. The branch group shall be selected by the Load Serving Entity based on the primary branch group upon which the energy or capacity from the particular resource commitment from outside the ISO Control Area has been historically scheduled or, for a resource commitment without a scheduling history, the primary branch group upon which the energy or capacity from the particular resource commitment from outside the ISO Control Area is anticipated to be scheduled. To the extent a particular branch group is over requested, such that the MWs represented in all requested resource commitments utilizing the branch group exceed the branch group's remaining import capacity, the requested resource commitment MW quantities will be allocated available capacity based on the "Import Capacity Load Share" ratio of each Load Serving Entity submitting such resource commitments. To the

extent this initial allocation has not fully assigned the total import capacity of a particular branch group to the requested resource commitments, the remaining capacity will be allocated until fully exhausted based on the Import Capacity Load Share ratio of each Load Serving Entity whose submitted resource commitment has not been fully satisfied.

a. Import Capacity Load Share is each Load Serving Entity's proportionate share of the forecasted 2007 coincident peak Load for the ISO Control Area relative to the total coincident peak Load of all Load Serving Entities that have not had their request for import capacity for a resource commitment on a particular branch group fully satisfied. The proportionate share of the forecasted 2007 peak Load for the ISO Control Area for each Load Serving Entity is the "Coincident Load Share," as determined by the California Energy Commission.

b. The ISO will notify the Scheduling Coordinator for each Load Serving Entity of the Load Serving Entity's Coincident Load Share. The ISO will further notify the Scheduling Coordinator for each Load Serving Entity of the amount of, and branch group on which, import capacity has been allocated to the Load Serving Entity pursuant to this Step 3. The import capacity allocated pursuant to this Step 3 shall be referred to as "Commitment Import Capacity."

4. Step 4: To the extent import capacity remains unallocated following Steps 1-3 above, the ISO will publish on its Website remaining aggregate import capacity, the identity of the branch groups with available capacity, and the MW quantity remaining on each such branch group. The remaining aggregate import capacity will be allocated to Load Serving Entities serving Load within the ISO Control Area through their Scheduling Coordinators based on each Load Serving Entity's Coincident Load Share. The quantity of import capacity allocated to a Load Serving Entity under this paragraph is that entity's "Remainder Import Capacity." This Step 4 does not allocate import capacity on a specific branch group, but rather allocates aggregate import capacity.

5. Step 5: Load Serving Entities shall be allowed to trade some or all of their Remainder Import Capacity or Commitment Import Capacity to any other Load Serving Entity or Market Participant

during a period of time established by ISO Market Notice. The ISO will accept trades among LSEs and Market Participants only to the extent such trades are reported to the ISO in a manner established by ISO Market Notice.

6. Step 6: Three business days after the close of the trading period set forth in Step 5 above, the Scheduling Coordinator for each Load Serving Entity or Market Participant shall notify the ISO of its request to allocate its post-trading Remainder Import Capacity on a MW per available branch group basis. The ISO will honor the requests to the extent a branch group has not been over requested. If a branch group is over requested, the requests for Remainder Import Capacity on that branch group will be allocated based on the ratio of each Load Serving Entity's Import Capacity Load Share, as used in Step 3. A Market Participant without a Coincident Load Share will be assigned the Coincident Load Share equal to the average Coincident Load Share of those Load Serving Entities from which it received Remainder Import Capacity. The ISO will notify each Scheduling Coordinator for Load Serving Entities or Market Participants of their accepted allocation under this Step 6.

7. Step 7: Following Step 6, the ISO will publish on its Website remaining aggregate import capacity, if any, the identity of the branch groups with available capacity, and the MW quantity remaining on each such branch group. To the extent import capacity remains unallocated, in the time period and manner established by ISO Market Notice, all Load Serving Entities or Market Participants shall notify the ISO of their requests to allocate any remaining Remainder Import Capacity on a MW per available branch group basis. The ISO will honor the requests to the extent a branch group has not been over requested. If a branch group is over requested, the requests on that branch group will be allocated based on the ratio of each Load Serving Entity or Market Participant's Import Capacity Load Share, as used in Steps 3 and 6. The ISO will notify each Scheduling Coordinator for a Load Serving Entity or Market Participant of the Load Serving Entity or Market Participant's accepted allocation under this Step 7. No further iterations will be permitted.

~~For 2006, the allocation will be as follows:~~

~~a. Non-CPUC Load Serving Entities will receive an allocation on a particular branch group equal to each entity's resource commitments outside the ISO Control Area, as of October 27, 2005 that utilizes the particular branch group through calendar year 2006.~~

~~b. CPUC Load Serving Entities will receive an aggregate import value by branch group that is equal to the maximum value for each branch group minus import capacity associated with (i) Existing Transmission Contracts, (ii) Encumbrances and Transmission Ownership Rights, and (iii) resource commitments outside the ISO Control Area of non-CPUC Load Serving Entities, as of October 27, 2005 as provided for in Section 40.5.2.2(a).~~

~~For 2007, the allocation will be as follows:~~

~~c. Non-CPUC Load Serving Entities will receive an allocation on a particular branch group equal to each entity's resource commitments outside the ISO Control Area, as of March 10, 2006 that utilizes the particular branch group through calendar year 2007.~~

~~d. CPUC Load Serving Entities will receive an aggregate import value by branch group that is equal to the maximum value for each branch group minus import capacity associated with (i) Existing Transmission Contracts, (ii) Encumbrances and Transmission Ownership Rights, and (iii) resource commitments outside the ISO Control Area of non-CPUC Load Serving Entities, as of March 10, 2006 as provided for in Section 40.5.2.2(c).~~

This multi-step allocation of total import capacity does not guarantee or result in any actual transmission service being allocated and is only used for determining the maximum import ~~Resource Adequacy~~ ~~C~~capacity that can be credited towards satisfying the Planning Reserve Margin of a Load Serving Entity under this Section 40. ~~a Scheduling Coordinator's Resource Adequacy obligation.~~ Upon the request of the ISO, Scheduling Coordinators must provide the ISO with information on existing import contracts and any trades or sales of their load share allocation. ~~Such information will be subject to the confidentiality provisions of this ISO Tariff.~~ To the extent that the ISO's review of Resource Adequacy Plans identifies reliance upon imports that exceed the import capacity allocated to the Load Serving Entity under this section, ~~T~~the ISO will inform the CPUC or ~~other~~ appropriate Local Regulatory Authority of any Resource Adequacy Plan submitted by a Scheduling Coordinator for a Load Serving Entity under their respective jurisdiction that exceeds its allocation of import capacity.

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40.6 Submission of Supply Plans.

Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity shall provide the ISO with annual and monthly Supply Plans<u>; however, Scheduling Coordinators for resources listed on schedule 14 of an MSS Agreement need not submit a Supply Plan, unless any capacity from such Schedule 14 resources has been sold to any Load Serving Entity other than the MSS Operator that owns or controls the resource</u>. The annual Supply Plan shall be provided by September 30th of each year. The monthly Supply Plan shall be provided on the last business day of the second month prior to the compliance month (e.g., March 31 for May). Both the annual and monthly Supply Plans shall be provided in the form set forth on the ISO's Website, listing their commitments to provide Resource Adequacy Capacity to any Load Serving Entity or Entities for the reporting period. ~~Such plans will be accorded protection in accordance with the confidentiality provisions of this ISO Tariff.~~

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40.6A Availability of Resource Adequacy Resources

40.6A.2 Available Generation.

For the purposes of Section 40.6A, a Resource Adequacy Resources' "Available Generation" shall be: (a) the Resource Adequacy Capacity of a Generating Unit, other than a Hydroelectric facility or a QF that is still under a power purchase agreement with a host utility, System Unit that has contracted to supply Resource Adequacy Capacity to a non-MSS Load Serving Entity serving Load with the ISO Control Area ~~or System Resource only to the extent the CPUC or other Local Regulatory Authority has imposed an obligation that System Resources relied upon by Load Serving Entities within their jurisdiction to meet Resource Adequacy requirements must be available to the ISO~~, adjusted for any outages or reductions in capacity reported to the ISO in accordance with this ISO Tariff, (b) minus the unit's scheduled operating level as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the unit committed to deliver Energy or provide Operating Reserve to the Resource Adequacy Resources' Generator's Native Load.

<u>In the case where the Resource Adequacy Resource is a System Resource, and to the extent the CPUC or other Local Regulatory Authority has imposed an obligation that System Resources relied upon by Load Serving Entities within their jurisdiction to meet Resource Adequacy requirements must be available to the ISO, the Available Generation of the System Resource shall be the Resource Adequacy Capacity of the System Resource adjusted for any outages or reductions in capacity reported to the ISO in accordance with this ISO Tariff, (b) minus the total amount of the System Resource's actual energy scheduled on the specific intertie of the import Resource Adequacy Capacity as identified in the ISO's Final Hour-Ahead Schedules, and (c) minus the amount of the System Resource's commitments on the specific intertie of the import Resource Adequacy Capacity to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator. The Available Generation of the System Resource shall never be less than zero.</u>

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40.6A.3 Reporting Requirements for Non-Participating Generators.

So that the ISO may determine the Available Generation of Resource Adequacy Resources, Resource Adequacy Resources<u>, other than non-resource specific System Resources and Qualifying Facilities ("QFs") with effective contracts under the Public Utilities Regulatory Policies Act,</u> that are not Participating Generators shall be required to file with the ISO: (i) the Generating Unit's minimum operating level; (ii) the Generating Unit's maximum operating level; and (iii) the Generating Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch Resource Adequacy Resources. In addition, Resource Adequacy Resources that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 40.6A, notify the ISO, as soon as practicable, of any Planned Maintenance Outages, Forced Outages, Force Majeure Event outages or any other reductions in their maximum operating levels or Resource Adequacy Capacity during the relevant month.

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40.6A.4 Obligation to Offer Available Capacity.

Except as set forth in Sections 40.6A.5 and 40.6A.6, all Resource Adequacy Resources shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 40.6A.2 and any other Available Generation beyond its Resource Adequacy Capacity shall be subject to the FERC must-offer obligation as set forth in Section 40.7. The Resource Adequacy Resource shall make available to the ISO Real Time Market all Resource Adequacy Capacity that is not subject to an outage or is otherwise participating in the ISO Market or included on a self-schedule. Notwithstanding the foregoing, a Resource Adequacy Resource that is a Participating Intermittent Resource satisfies its obligation to offer Available Generation under this Section by scheduling in accordance with Appendix Q of the ISO Tariff.

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40.6A.5 Submission of Bids and Applicability of the Proxy Price.

For each Operating Hour, the Scheduling Coordinator for the Resource Adequacy Resources shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 34.2. In addition, the ISO shall calculate for each gas-fired Resource Adequacy Resource (other than gas-fired Resource Adequacy Resources which are also System Resources), in accordance with Section 40.10.1, a Proxy Price for Energy.

If a Scheduling Coordinator for the Resource Adequacy Resource fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the un-bid quantity of the Resource Adequacy Resource's Available Generation will be deemed by the ISO to be bid at the Resource Adequacy Resource's Proxy Price if (i) the Resource Adequacy Resource is a gas-fired Generating Unit and (ii) the Resource Adequacy Resource has provided the ISO with adequate data in compliance with Section 40.6A.3 for the applicable Generating Unit. For all other Resource Adequacy Resources that are Generating Units, the un-bid quantity of the Resource Adequacy Resources' Available

Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order the ISO will insert this un-bid quantity into the Resource Adequacy Resource's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the Resource Adequacy Resources' Available Generation.

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40.6A.7 Penalties for Non-Compliance.

In addition to any other penalty or settlement consequence of a failure of a unit to operate in accordance with a ISO operating order, the failure of a Scheduling Coordinator for a Resource Adequacy Resource to make the Resource Adequacy Resource ~~itself~~ available to the ISO in accordance with the requirements of Section 40 of this ISO Tariff or to operate the Resource Adequacy Resource by placing it online or in a manner consistent with a submitted Supplemental Energy bid or Proxy Price Energy Bid shall result in that Scheduling Coordinator being subject to the sanctions set forth in Section 37.2 of the ISO Tariff.

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40.13.12 System Resources.

40.13.12.2 Non-Dynamically Scheduled System Resources.

For Non-Dynamically Scheduled System Resources, the Scheduling Coordinator must demonstrate that the Load Serving Entity upon which the Scheduling Coordinator is scheduling Demand has an allocation of import allocation at the import Scheduling Point under Section 40.5.2.2 of the ISO Tariff that is not less than the Resource Adequacy Capacity from the Non-Dynamically Scheduled System Resource ~~and cannot be curtailed for economic reasons~~. Eligibility as Resource Adequacy Capacity would be contingent upon a showing by the Scheduling Coordinator of the System Resource that it has secured transmission through any intervening Control Areas for the operating hours that cannot be curtailed for economic reasons or bumped by higher priority transmission. ~~of securing in any intervening Control Areas transmission for the operating hours making use of highest priority transmission offered by the intervening Transmission Operator that cannot be curtailed for economic reasons.~~

With respect to Non-Dynamically Scheduled System Resources, any inter-temporal constraints such as multi-hour run blocks, must be explicitly identified in the monthly Resource Adequacy Plan, and no constraints may be imposed beyond those explicitly stated in the plan.

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ATTACHMENT B

(d) transactions between Scheduling Coordinators;

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

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

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

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

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

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

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

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

20.3 Other Parties.

No Market Participant shall have the right hereunder to receive from the ISO or to review any documents, data or other information of another Market Participant to the extent such documents, data or information is to be treated as in accordance with Section 20.2; provided, however, a Market Participant may receive and review any composite documents, data, and other information that may be developed based upon such confidential documents, data, or information, if the composite document does not disclose such confidential data or information relating to an individual Market Participant and provided, however, that the ISO may disclose information as provided for in its bylaws.

20.4 Disclosure.

Notwithstanding anything in this Section 20 to the contrary,

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

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

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

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

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

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

20.5 Confidentiality.

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

21 SCHEDULE VALIDATION TOLERANCES.

21.1 Temporary Simplification of Schedule Validation Tolerances.

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

40.2 Submission of Annual and Monthly Resource Adequacy Plan.

40.2.1 Annual Resource Adequacy Plan.

Each Scheduling Coordinator for a Load Serving Entity serving Load within the ISO Control Area must provide the ISO with an annual Resource Adequacy Plan; however, Scheduling Coordinators representing a Load Serving Entity with an MSS Agreement shall submit the information required by this section pursuant to the terms and formal standards set forth in the MSS Agreement. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted on the schedule and in the form approved by the CPUC. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area, except Load Serving Entities with an MSS Agreement, shall be submitted no later than October 25th of each year and in the form set forth on the ISO Website. Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities should be identical. The annual Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin under Section 40.4, or portion thereof as established by the CPUC or applicable Local Regulatory Authority, and must apply the Net Qualifying Capacity requirements of Section 40.5.2.

40.2.2 Monthly Resource Adequacy Plan.

Each Scheduling Coordinator for a Load Serving Entity serving Load within the ISO Control Area must provide the ISO with a monthly Resource Adequacy Plan; however, (1) Scheduling Coordinators representing a Load Serving Entity with an MSS Agreement shall submit the information required by this section pursuant to the terms and formal standards set forth in the MSS Agreement and (2) Scheduling Coordinators for a Load Serving Entity serving Load within the ISO Control Area in a forecasted peak amount of less than (1) MW on average per day over the compliance year may notify the ISO that the Load Serving Entity's annual Resource Adequacy Plan pursuant to Section 40.2.1 will constitute its monthly Resource Adequacy Plan under this section for each month of the following compliance year.

The monthly Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted on the schedule and in the form approved by the CPUC. The monthly Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area, except for Load Serving Entities with an MSS Agreement, shall be submitted no later than on the last business day of the second month prior to the compliance month (e.g., March 31 for May) and in the form set forth on the ISO's Website. Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities should be identical. The monthly Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin under Section 40.4 for the relevant reporting month and must apply the Net Qualifying Capacity requirements of Section 40.5.2.

40.2.3 Resource Adequacy Plan Compliance.

The ISO will evaluate whether each monthly Resource Adequacy Plan submitted by a Scheduling Coordinator on behalf of a Load Serving Entity serving Load within the ISO Control Area satisfies the Load Serving Entity's obligation to procure sufficient Net Qualifying Capacity to comply with its Planning Reserve Margin under Section 40.4. If a Scheduling Coordinator for a Load Serving Entity submits a Resource Adequacy Plan that the ISO identifies as not demonstrating compliance with Resource Adequacy rules adopted by the CPUC or other Local Regulatory Authority, as applicable, the ISO will, within 10 business days, first notify the relevant Scheduling Coordinator, or in the case of a mismatch between Resource Adequacy Plan(s) and Supply Plan(s), the relevant Scheduling Coordinators in an attempt to resolve the issue. If this process does not resolve the ISO's concern, the ISO will notify the CPUC or other appropriate Local Regulatory Authority of the potential deficiency. To the extent that the CPUC or other appropriate Local Regulatory Authority allows Load Serving Entities under its jurisdiction to cure the identified deficiency or determines that no deficiency exists, the Scheduling Coordinator shall inform the ISO at least 10 days before the effective month. If the deficiency is not resolved prior to the 10th day before the effective month, the ISO will use the information contained in the Supply Plan to set

Resource Adequacy Resources' obligations under this section of the ISO Tariff for the applicable reporting month.

40.3 Demand Forecasts.

The annual and monthly Resource Adequacy Plans must include a Demand Forecast as follows:

a. For CPUC Load Serving Entities, the Demand Forecast shall be the Demand Forecast required by the CPUC. To the extent the ISO has not received a CPUC Load Serving Entity's load forecast through the CPUC's Resource Adequacy process, the Scheduling Coordinators for the CPUC Load Serving Entities must provide to the ISO a copy of the Demand Forecast that they provided to the CPUC and CEC, subject to the confidentiality terms established by the CPUC in its proceeding.

b. For non-CPUC Load Serving Entities, the Demand Forecast shall be the Demand Forecast required by the applicable Local Regulatory Authority. Scheduling Coordinators for non-CPUC Load Serving Entities must provide data and/or supporting information, as requested by the ISO, for the Demand Forecasts required by this Section for each represented non-CPUC Load Serving Entity.

c. If the CPUC or other Local Regulatory Authority has not established a requirement to prepare a Demand Forecast, the Scheduling Coordinator for the Load Serving Entity shall prepare and provide the ISO with a Demand Forecast that shall be the Load Serving Entity's monthly non-coincident peak Demand Forecast for its Service Area, for its MSS area, or in each Service Area of an Original Participating TO in which the Load Serving Entity serves Load, unless the Load Serving Entity agrees to utilize a coincident peak determination provided by the California Energy Commission for such Load Serving Entity. Scheduling Coordinators for Load Serving Entities covered by this subsection must provide data and/or supporting information, as requested by the ISO, for the Demand Forecasts required by this Section for each represented Load Serving Entity.

For Load Serving Entities that are local publicly owned electric utilities as defined in Section 9604 of the PUC, the Demand Forecasts required by this Section 40.3 should be consistent with Section 9620(a) of the PUC, as it may be amended from time to time, requiring that such Load Serving Entities meet their

Planning Reserve Margin, peak demand, and operating reserves.

40.4 Planning Reserve Margin.

The monthly Resource Adequacy Plan must include a level of Resource Adequacy Capacity sufficient to meet 100% of the Demand Forecast in Section 40.3 plus a Planning Reserve Margin as follows:

a. For Scheduling Coordinators representing CPUC Load Serving Entities, the Planning Reserve Margin shall be that adopted by the CPUC.

b. For Scheduling Coordinators representing non-CPUC Load Serving Entities, the Planning Reserve Margin shall be that adopted by the appropriate Local Regulatory Authority.

c. For Scheduling Coordinators representing Load Serving Entities for which the CPUC or other Local Regulatory Authority has not established a Planning Reserve Margin as of May 31, 2006, the Planning Reserve Margin shall be: (1) for compliance months June through September 2006, the Planning Reserve Margin provided by the Load Serving Entity to accommodate any processes to approve the Planning Reserve Margin that may be pending before the applicable Local Regulatory Authority and (2) thereafter, no less than 115% of the peak hour of the month in the Demand Forecast set forth in Section 40.3.

40.5 Determination of Resource Adequacy Capacity.

Resource Adequacy Capacity shall be the quantity of capacity in MWs from a resource listed in a Resource Adequacy Plan. Resource Adequacy Capacity cannot exceed a resource's Net Qualifying Capacity.

40.5.1 Qualifying Capacity.

Qualifying Capacity is the capacity from a resource prior to application of the Net Capacity provisions of Section 40.5.2. The criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO. For compliance months June through September 2006, the criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types may be provided by the Load Serving Entity to accommodate any processes to approve the Qualifying Capacity criteria that may be pending before the applicable Local Regulatory Authority. Only if such criteria are not provided by the CPUC or other Local Regulatory Authority by August 31, 2006 for compliance month October 2006, then Section 40.13 will apply. The ISO shall use the criteria provided by the CPUC, other Local Regulatory Authority or, if necessary, Section 40.13, to determine and verify, if necessary, the Qualifying Capacity of all resources listed in a Resource Adequacy Plan; however, to the extent a resource is listed by one or more Scheduling Coordinators in their respective Resource Adequacy Plans, which apply the criteria of more than one regulatory entity that leads to conflicting Qualifying Capacity values for that resource, the ISO will apply the respective Qualifying Capacity formulas applicable for each Load Serving Entity.

40.5.2 Net Qualifying Capacity.

Net Qualifying Capacity is Qualifying Capacity, determined under the criteria provided by the CPUC or other Local Regulatory Authority or, if such criteria is not provided by the CPUC or Local Regulatory Authority, under Section 40.13 of this ISO Tariff, reduced, as applicable, based on: (1) testing and verification or (2) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the ISO pursuant to the provisions of this ISO Tariff. The ISO shall produce a report, posted to the ISO Website and updated from time to time, setting forth the Net Qualifying Capacity of Participating Generators. All other resources may be included in the report under this Section upon their request. Any disputes as to the ISO's determination regarding Net Qualifying Capacity shall be subject to the ISO's alternative dispute resolution procedures.

40.5.2.1 Deliverability Within the ISO Control Area.

In order to determine Net Qualifying Capacity from a Generating Unit, the ISO will determine that the Generating Unit is able to serve the aggregate of Load by means of a deliverability analysis. The deliverability analysis will be performed annually and shall focus on peak Demand conditions. The ISO will review its input assumptions and draft results with Market Participants before completing its determination. The ISO will coordinate with the CPUC and other Local Regulatory Authorities so that the results of the deliverability analysis can be incorporated in annual and monthly Resource Adequacy Plans. The results of the ISO's 2006 deliverability analysis shall be effective for a period no shorter than compliance year 2007. To the extent the deliverability analysis shows that the Qualifying Capacity of a Generating Unit is not deliverable to the aggregate of Load under the conditions studied, the Qualifying Capacity of the Generating Unit will be reduced on a MW basis for the capacity that is undeliverable.

40.5.2.2 Deliverability of Imports.

This Section 40.5.2.2 shall apply only to Resource Adequacy Plans covering the period through December 31, 2007, unless superseded earlier by alternative ISO Tariff provisions. Total import capacity will be assigned to Load Serving Entities serving Load in the ISO Control Area and other Market Participants, if applicable, for 2007 as described by the following sequence of steps.

1. Step 1: The ISO shall establish for 2007 for each branch group the total import capacity values for the ISO Control Area, and will post those values on the ISO Website by July 1, 2006.

2. Step 2: For each branch group, the total capacity established in Step 1 will be reduced by subtracting the import capacity associated with (i) Existing Transmission and (ii) encumbrances and transmission ownership rights. Existing Contracts and encumbrances and transmission ownership rights therefore shall be reserved for holders of such commitments as part of the deliverability study and will not be subject to allocation under this Section.

3. Step 3: From the amount of import capacity remaining on each branch group determined in Step 2 above, Load Serving Entities serving Load within the ISO Control Area will receive, to the extent feasible, an allocation on a particular branch group selected by the Load Serving Entity equal to each entity's resource commitments from outside the ISO Control Area, as of March 10, 2006, the terms of which runs through at least calendar year 2007. The branch group shall be selected by the Load Serving Entity based on the primary branch group upon which the energy or capacity from the particular resource commitment from outside the ISO Control Area has been historically scheduled or, for a resource commitment without a scheduling history, the primary branch group upon which the energy or capacity from the particular resource commitment from outside the ISO Control Area is anticipated to be scheduled. To the extent a particular branch group is over requested, such that the MWs represented in all requested resource commitments utilizing the branch group exceed the branch group's remaining import capacity, the requested resource commitment MW quantities will be allocated available capacity based on the "Import Capacity Load Share" ratio of each Load Serving Entity submitting such resource commitments. To the extent this initial allocation has not fully assigned the total import capacity of a particular branch

group to the requested resource commitments, the remaining capacity will be allocated until fully exhausted based on the Import Capacity Load Share ratio of each Load Serving Entity whose submitted resource commitment has not been fully satisfied.

a. Import Capacity Load Share is each Load Serving Entity's proportionate share of the forecasted 2007 coincident peak Load for the ISO Control Area relative to the total coincident peak Load of all Load Serving Entities that have not had their request for import capacity for a resource commitment on a particular branch group fully satisfied. The proportionate share of the forecasted 2007 peak Load for the ISO Control Area for each Load Serving Entity is the "Coincident Load Share," as determined by the California Energy Commission.

b. The ISO will notify the Scheduling Coordinator for each Load Serving Entity of the Load Serving Entity's Coincident Load Share. The ISO will further notify the Scheduling Coordinator for each Load Serving Entity of the amount of, and branch group on which, import capacity has been allocated to the Load Serving Entity pursuant to this Step 3. The import capacity allocated pursuant to this Step 3 shall be referred to as "Commitment Import Capacity."

4. Step 4: To the extent import capacity remains unallocated following Steps 1-3 above, the ISO will publish on its Website remaining aggregate import capacity, the identity of the branch groups with available capacity, and the MW quantity remaining on each such branch group. The remaining aggregate import capacity will be allocated to Load Serving Entities serving Load within the ISO Control Area through their Scheduling Coordinators based on each Load Serving Entity's Coincident Load Share. The quantity of import capacity allocated to a Load Serving Entity under this paragraph is that entity's "Remainder Import Capacity." This Step 4 does not allocate import capacity on a specific branch group, but rather allocates aggregate import capacity.

5. Step 5: Load Serving Entities shall be allowed to trade some or all of their Remainder Import Capacity or Commitment Import Capacity to any other Load Serving Entity or Market Participant during a period of time established by ISO Market Notice. The ISO will accept trades among

LSEs and Market Participants only to the extent such trades are reported to the ISO in a manner established by ISO Market Notice.

6. Step 6: Three business days after the close of the trading period set forth in Step 5 above, the Scheduling Coordinator for each Load Serving Entity or Market Participant shall notify the ISO of its request to allocate its post-trading Remainder Import Capacity on a MW per available branch group basis. The ISO will honor the requests to the extent a branch group has not been over requested. If a branch group is over requested, the requests for Remainder Import Capacity on that branch group will be allocated based on the ratio of each Load Serving Entity's Import Capacity Load Share, as used in Step 3. A Market Participant without a Coincident Load Share will be assigned the Coincident Load Share equal to the average Coincident Load Share of those Load Serving Entities from which it received Remainder Import Capacity. The ISO will notify each Scheduling Coordinator for Load Serving Entities or Market Participants of their accepted allocation under this Step 6.

7. Step 7: Following Step 6, the ISO will publish on its Website remaining aggregate import capacity, if any, the identity of the branch groups with available capacity, and the MW quantity remaining on each such branch group. To the extent import capacity remains unallocated, in the time period and manner established by ISO Market Notice, all Load Serving Entities or Market Participants shall notify the ISO of their requests to allocate any remaining Remainder Import Capacity on a MW per available branch group basis. The ISO will honor the requests to the extent a branch group has not been over requested. If a branch group is over requested, the requests on that branch group will be allocated based on the ratio of each Load Serving Entity or Market Participant's Import Capacity Load Share, as used in Steps 3 and 6. The ISO will notify each Scheduling Coordinator for a Load Serving Entity or Market Participant of the Load Serving Entity or Market Participant's accepted allocation under this Step 7. No further iterations will be permitted.

This multi-step allocation of total import capacity does not guarantee or result in any actual transmission service being allocated and is only used for determining the maximum import capacity that can be credited towards satisfying the Planning Reserve Margin of a Load Serving Entity under this Section 40. Upon the request of the ISO, Scheduling Coordinators must provide the ISO with information on existing import contracts and any trades or sales of their load share allocation. To the extent that the ISO's review of Resource Adequacy Plans identifies reliance upon imports that exceed the import capacity allocated to the Load Serving Entity under this section, the ISO will inform the CPUC or appropriate Local Regulatory Authority of any Resource Adequacy Plan submitted by a Scheduling Coordinator for a Load Serving Entity under their respective jurisdiction that exceeds its allocation of import capacity.

40.6 Submission of Supply Plans.

Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity shall provide the ISO with annual and monthly Supply Plans; however, Scheduling Coordinators for resources listed on schedule 14 of an MSS Agreement need not submit a Supply Plan, unless any capacity from such Schedule 14 resources has been sold to any Load Serving Entity other than the MSS Operator that owns or controls the resource. The annual Supply Plan shall be provided by September 30th of each year. The monthly Supply Plan shall be provided on the last business day of the second month prior to the compliance month (e.g., March 31 for May). Both the annual and monthly Supply Plans shall be provided in the form set forth on the ISO's Website, listing their commitments to provide Resource Adequacy Capacity to any Load Serving Entity or Entities for the reporting period.

40.6.1 Compliance with Supply Plan Obligation.

Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity that fail to provide the ISO with annual or monthly Supply Plans as set forth in this ISO Tariff shall be subject to Section 37.6.1 of the ISO Tariff.

40.6A Availability of Resource Adequacy Resources.

40.6A.1 Applicability.

The requirements of Section 40.6A shall apply to all Resource Adequacy Resources identified on the Resource Adequacy Plans submitted by Scheduling Coordinators for Load Serving Entities serving Load in the ISO Control Area other than Resource Adequacy Resources identified exclusively on the Resource Adequacy Plans of (i) Load Serving Entities that have entered into a Metered Subsystem Agreement with the ISO and (ii) the State Water Project.

40.6A.2 Available Generation.

For the purposes of Section 40.6A, a Resource Adequacy Resources' "Available Generation" shall be: (a) the Resource Adequacy Capacity of a Generating Unit, other than a Hydroelectric facility or a QF that is still under a power purchase agreement with a host utility, System Unit that has contracted to supply Resource Adequacy Capacity to a non-MSS Load Serving Entity serving Load with the ISO Control Area, adjusted for any outages or reductions in capacity reported to the ISO in accordance with this ISO Tariff, (b) minus the unit's scheduled operating level as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the unit committed to deliver Energy or provide Operating Reserve to the Resource Adequacy Resources' Generator's Native Load.

In the case where the Resource Adequacy Resource is a System Resource, and to the extent the CPUC or other Local Regulatory Authority has imposed an obligation that System Resources relied upon by Load Serving Entities within their jurisdiction to meet Resource Adequacy requirements must be available to the ISO, the Available Generation of the System Resource shall be the Resource Adequacy Capacity of the System Resource adjusted for any outages or reductions in capacity reported to the ISO in accordance with this ISO Tariff, (b) minus the total amount of the System Resource's actual energy scheduled on the specific intertie of the import Resource Adequacy Capacity as identified in the ISO's Final Hour-Ahead Schedules, and (c) minus the amount of the System Resource's commitments on the specific intertie of the import Resource Adequacy Capacity to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator. The Available Generation of the System Resource shall never be less than zero.

40.6A.3 Reporting Requirements for Non-Participating Generators.

So that the ISO may determine the Available Generation of Resource Adequacy Resources, Resource Adequacy Resources, other than non-resource specific System Resources and Qualifying Facilities ("QFs") with effective contracts under the Public Utilities Regulatory Policies Act, that are not Participating Generators shall be required to file with the ISO: (i) the Generating Unit's minimum operating level; (ii) the Generating Unit's maximum operating level; and (iii) the Generating Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch Resource Adequacy Resources. In addition, Resource Adequacy Resources that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 40.6A, notify the ISO, as soon as practicable, of any Planned Maintenance Outages, Forced Outages, Force Majeure Event outages or any other reductions in their maximum operating levels or Resource Adequacy Capacity during the relevant month.

40.6A.4 Obligation to Offer Available Capacity.

Except as set forth in Sections 40.6A.5 and 40.6A.6, all Resource Adequacy Resources shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 40.6A.2 and any other Available Generation beyond its Resource Adequacy Capacity shall be subject to the FERC must-offer obligation as set forth in Section 40.7. The Resource Adequacy Resource shall make available to the ISO Real Time Market all Resource Adequacy Capacity that is not subject to an outage or is otherwise participating in the ISO Market or included on a self-schedule. Notwithstanding the foregoing, a Resource Adequacy Resource that is a Participating Intermittent Resource satisfies its obligation to offer Available Generation under this Section by scheduling in accordance with Appendix Q of the ISO Tariff.

40.6A.5 Submission of Bids and Applicability of the Proxy Price.

For each Operating Hour, the Scheduling Coordinator for the Resource Adequacy Resource shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 34.2. In addition, the ISO shall calculate for each gas-fired Resource Adequacy Resource (other than gas-fired Resource Adequacy Resources which are also System Resources), in accordance with Section 40.10.1, a Proxy Price for Energy.

If a Scheduling Coordinator for the Resource Adequacy Resource fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the un-bid quantity of the Resource Adequacy Resource's Available Generation will be deemed by the ISO to be bid at the Resource Adequacy Resource's Proxy Price if (i) the Resource Adequacy Resource is a gas-fired Generating Unit and (ii) the Resource Adequacy Resource has provided the ISO with adequate data in compliance with Section 40.6A.3 for the applicable Generating Unit. For all other Resource Adequacy Resources that are Generating Units, the un-bid quantity of the Resource Adequacy Resources' Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order the ISO will insert this un-bid quantity into the Resource Adequacy Resource's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the Resource Adequacy Resources' Available Generation.

Adequacy Resources of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m. (beginning of Hour Ending 11) on the day before; (3) end Waiver Denial Periods at any time; (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to the time a unit would be required to be on-line generating at its Pmin; and (5) revoke a waiver denial for a Short-Start Resource Adequacy Resource at any time and such revocation will be communicated via a ISO real-time dispatch or unit commitment instruction.

40.6A.7 Penalties for Non-Compliance.

In addition to any other penalty or settlement consequence of a failure of a unit to operate in accordance with a ISO operating order, the failure of a Scheduling Coordinator for a Resource Adequacy Resource to make the Resource Adequacy Resource available to the ISO in accordance with the requirements of Section 40 of this ISO Tariff or to operate the Resource Adequacy Resource by placing it online or in a manner consistent with a submitted Supplemental Energy bid or Proxy Price Energy Bid shall result in that Scheduling Coordinator being subject to the sanctions set forth in Section 37.2 of the ISO Tariff.

40.6B Recovery of Minimum Load Costs By Resource Adequacy Resources.

40.6B.1 Eligibility.

Except as set forth below, Resource Adequacy Resources that are Generating Units and System Units for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity shall be eligible to recover Un-Recovered Minimum Load Costs during Waiver Denial Periods. Units from Resource Adequacy Resources that incur Minimum Load Costs during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Resource Adequacy Resource has a Final Hour-Ahead Energy Schedule, the Resource Adequacy Resource shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a Resource Adequacy Resource generating at minimum load in compliance with the supply obligation, produces a quantity of Energy that varies from its minimum operating level by more than the Tolerance Band, the Resource Adequacy Resource shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a Resource Adequacy Resource produces a quantity of

40.13.11 Facilities Under Construction.

The Qualifying Capacity for facilities under construction will be determined based on the type of resource as described elsewhere in this Section. In addition, the facility must have been in commercial operation for no less than one month to be eligible to be included as a Resource Adequacy Resource in a Scheduling Coordinator's monthly plan.

40.13.12 System Resources.

40.13.12.1 Dynamically Scheduled System Resources.

Dynamically Scheduled System Resources shall be treated similar to resources within the ISO Control Area, except with respect to the deliverability screen under Section 40.5.2.1. However, eligibility as a Resource Adequacy Resource is contingent upon a showing by the Scheduling Coordinator that the Dynamically Scheduled System Resource has secured transmission through any intervening Control Areas for the operating hours that cannot be curtailed for economic reasons or bumped by higher priority transmission and that the Load Serving Entity upon which the Scheduling Coordinator is scheduling Demand has an allocation of import capacity at the import Scheduling Point under Section 40.5.2.2 of the ISO Tariff that is not less than the Resource Adequacy Capacity provided by the Dynamically Scheduled System Resource.

40.13.12.2 Non-Dynamically Scheduled System Resources.

For Non-Dynamically Scheduled System Resources, the Scheduling Coordinator must demonstrate that the Load Serving Entity upon which the Scheduling Coordinator is scheduling Demand has an allocation of import allocation at the import Scheduling Point under Section 40.5.2.2 of the ISO Tariff that is not less than the Resource Adequacy Capacity from the Non-Dynamically Scheduled System Resource. Eligibility as Resource Adequacy Capacity would be contingent upon a showing by the Scheduling Coordinator of the System Resource that it has secured transmission through any intervening Control Areas for the operating hours that cannot be curtailed for economic reasons or bumped by higher priority transmission.

With respect to Non-Dynamically Scheduled System Resources, any inter-temporal constraints such as multi-hour run blocks, must be explicitly identified in the monthly Resource Adequacy Plan, and no

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Operator provides documentation to the ISO by November 1 of any year demonstrating that the MSS Operator has secured generating capacity for the following calendar year at least equal to one hundred and fifteen percent (115%), on an annual basis, of the peak Demand responsibility of the MSS Operator, the ISO shall grant the exemption. Eligible generating capacity for such a demonstration may include on-demand rights to Energy, peaking resources, and Demand reduction programs. The peak Demand responsibility of the MSS Operator shall be equal to the annual peak Demand Forecast of the MSS Load plus any firm power sales by the MSS Operator, less interruptible Loads, and less any firm power purchases. Firm power for the purposes of this Section 4.9.16.2 shall be Energy that is intended to be available to the purchaser without being subject to interruption or curtailment by the supplier except for Uncontrollable Forces or emergency. To the extent that the MSS Operator demonstrates that it has secured generating capacity in accordance with this Section 4.9.16.2., the Scheduling Coordinator for the MSS Operator shall not be obligated to bear any share of the ISO's costs for any summer Demand reduction program or for any summer reliability Generation procurement program pursuant to ISO Tariff Section 42.1.8 for the calendar year for which the demonstration is made.

4.9.16.3 If the ISO is compensating Generating Units for Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs, and if MSS Operator charges the ISO for the Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs, of the Generating Units serving the Load of the MSS, then the Scheduling Coordinator for the MSS shall bear its proportionate share of the total amount of those costs incurred by the ISO based on the MSS gross metered Demand and exports and the Generating Units shall be made available to the ISO through the submittal of Supplemental Energy bids. If the MSS

Operator chooses not to charge the ISO for the Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs of the Generating Units serving the Load of the MSS, then the Scheduling Coordinator for the MSS shall bear its proportionate share of the total amount of those costs incurred by the ISO based on the MSS's net metered Demand and exports. The MSS Operator shall make the election whether to charge the ISO for these costs on an annual basis on November 1 for the following calendar year.

4.9.16.4 The Scheduling Coordinator for the MSS shall be responsible for Transmission Losses, in accordance with the ISO Tariff, only within the MSS, at any points of interconnection between the MSS

8.3.4 The ISO shall procure on a daily and hourly basis, each day, Regulation, Spinning, Non-Spinning and Replacement Reserves. The ISO shall procure Replacement Reserve on a longer-term basis pursuant to Section 42.1.3 if necessary to meet reliability criteria. The ISO Governing Board must approve all long-term Replacement Reserve contracts. The ISO shall contract for Voltage Support annually (or for such other period as the ISO may determine is economically advantageous) and on a daily or hourly basis as required to maintain System Reliability. The ISO shall contract annually (or for such other period as the ISO may determine is economically advantageous) for Black Start Generation.

8.4 Technical Requirements for Providing Ancillary Services.

All Generating Units, System Units, Loads and System Resources providing Ancillary Services shall comply with the technical requirements set out in Sections 8.4.1 to 8.4.6.1 below relating to their operating capabilities, communication capabilities and metering infrastructure. No Scheduling Coordinator shall be permitted to submit a bid to the ISO for the provision of an Ancillary Service from a Generating Unit, System Unit, Load or System Resource, or to submit a Schedule for self-provision of an Ancillary Service from that Generating Unit, System Unit, Load or System Resource, unless the Scheduling Coordinator is in possession of a current certificate issued by the ISO confirming that the Generating Unit, System Unit, Load or System Resource complies with the ISO's technical requirements for providing the Ancillary Service concerned. Scheduling Coordinators can apply for Ancillary Services certificates in accordance with the ISO's Protocols for considering and processing such applications. The ISO shall have the right to inspect Generating Units, Loads or the individual resources comprising System Units and other equipment for the purposes of the issue of a certificate and periodically thereafter to satisfy itself that its technical requirements continue to be met. If at any time the ISO's technical requirements are not being met, the ISO may withdraw the certificate for the Generating Unit, System Unit, Load or System Resource concerned.

set forth in Section 40.7, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units or System Units, if any, bidding to provide these services. Accordingly, except as set forth under Section 40.7, the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units or System Units, if any, to facilitate delivery of Energy from Ancillary Services.

Notwithstanding the foregoing, a Scheduling Coordinator who has sold or self-provided Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity to the ISO in the Day-Ahead Market shall be required to replace that capacity in whole or in part from the ISO if the scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or if the Ancillary Service associated with a Generating Unit, Curtailable Demand, or System Resource successfully bid in a Day-Ahead Ancillary Service Market is reduced in the Hour-Ahead Market, for any reason (other than the negligence or willful misconduct of the ISO, or a Scheduling Coordinator's involuntary decrease in such sold capacity or scheduled self-provision on the instruction of the ISO). The price for such replaced Ancillary Service shall be the Market Clearing Price in the Hour-Ahead Market for the Ancillary Service for the Settlement Period concerned for the Zone in which the Generating Units or other resources are located. The ISO will purchase the Ancillary Service concerned from another Scheduling Coordinator in the Hour-Ahead Market in accordance with the provisions of the ISO Tariff.

8.8 Black Start.

(a) Black Start shall meet the standards specified for Black Start in this Tariff and Appendix K; and

(b) the ISO will Dispatch Black Start as required in accordance with the applicable Black Start agreement.

8.9 [Not Used]

8.10 Verification, Compliance Testing, and Audit of Ancillary Services.

Availability of both contracted and self-provided Ancillary Services shall be verified by the ISO by unannounced testing of Generating Units, Loads and System Resources, by auditing of response to ISO specific requirements of the ISO. The cost associated with each Dispatch instruction is broken into two components:

a) the portion of the Energy payment at or below the Market Clearing Price ("MCP") for the Settlement Interval, and

b) the portion of the Energy payment above the MCP, if any, for the Settlement Interval.

For each Settlement Interval, costs above the MCP incurred by the ISO for such Dispatch instructions necessary as a result of a transmission facility Outage or in order to satisfy a location-specific requirement in that Settlement Interval shall be payable to the ISO by the Participating Transmission Owner in whose PTO Service Territory the transmission facility is located or the location-specific requirement arose. The costs incurred by the ISO for such Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement will be recovered in the same way as for Instructed Imbalance Energy.

11.2.4.2.1.1 Allocation of Costs from Out-Of-Market calls to Condition 2 RMR Units.

All costs associated with energy provided by a Condition 2 RMR Unit operating other than according to a dispatch notice issued under the RMR Contract shall be allocated in accordance with Section 11.2.4.2.1. Until either the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups exceed the relevant RMR Contract Service Limit, any cost incurred for energy provided under the RMR Contract above the rate specified in equation 1a or 1b as set forth in Section 11.2.4.2 shall be allocated in accordance with Section 11.2.4.2.1, not to the Responsible Utility.

Start-Up Costs for Condition 2 RMR Units providing service outside the RMR Contract, and any additional Start-Up Cost associated with a Condition 2 RMR Unit providing service under the RMR Contract when the unit's total service has exceeded an RMR Contract Service Limit but neither the RMR Contract Counted MWh, Counted Service Hours or Counted Start-ups have exceeded the applicable RMR Contract Service Limit, shall be invoiced in accordance with Section 40.12.6 and collected in accordance with Section 40.12.1.

11.2.10 Payments Under Section 42.1 Contracts.

The ISO shall calculate and levy charges for the recovery of costs incurred under contracts entered into by the ISO under the authority granted in Section 42.1 in accordance with Section 42.1.8 of this ISO Tariff.

11.2.11 Obligation for FERC Annual Charges.

11.2.11.1 Each Scheduling Coordinator shall be obligated to pay for the FERC Annual Charges for its use of the ISO Controlled Grid to transmit electricity, including any use of the ISO Controlled Grid through Existing Contracts scheduled by the Scheduling Coordinator. Any FERC Annual Charges to be assessed by FERC against the ISO for such use of the ISO Controlled Grid shall be assessed against Scheduling Coordinators at the FERC Annual Charge Recovery Rate, as determined in accordance with this Section 11.2.11. Such assessment shall be levied monthly against all Scheduling Coordinators based upon each Scheduling Coordinator's metered Demand and exports.

11.2.11.2 Scheduling Coordinators may elect, each year, to pay the FERC Annual Charges assessed against them by the ISO either on a monthly basis or an annual basis. Scheduling Coordinators that elect to pay FERC Annual Charges on a monthly basis shall make payment for such charges within five (5) Business Days after issuance of the monthly invoice. The FERC Annual Charges will be issued to Market Participants once a month, on the first business day after the final market and Grid Management Charge invoices are issued for the trade month. Once the final FERC Annual Charge Recovery Rate is received from FERC in the Spring/Summer of the following year, a supplemental invoice will be issued. Scheduling Coordinators that elect to pay FERC Annual Charges on an annual basis shall make payment for such charges within five (5) Business Days after the ISO issues such supplemental invoice. Scheduling Coordinators that elect to pay FERC Annual Charges on an annual basis shall maintain either an Approved Credit Rating, as defined with respect to either payment of the Grid Management Charge, or payment of other charges, or shall maintain security in accordance with Section 12.1.

11.2.14 Credits and Debits of FERC Annual Charges Collected from Scheduling Coordinators.

In addition to the surcharges or credits permitted under Sections 11.2.13 or 11.6.3.3 of this ISO Tariff, the ISO shall credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of FERC Annual Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

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

11.2.16 Emissions and Start-Up Fuel Cost Charges.

The ISO shall calculate, account for and settle charges and payments for Emissions Costs and Start-Up Fuel Costs in accordance with Sections 40.11 and 40.12 of this ISO Tariff.

11.2.17 The ISO shall calculate, charge and disburse all collected default Interest in accordance with the ISO Tariff.

11.2.18 Auditing

All of the data, information, and estimates the ISO uses to calculate these amounts shall be subject to the auditing requirements of Section 10.2.11 of the ISO Tariff. The ISO shall calculate these amounts using the software referred to in Section 11.4. 4except in cases of system breakdown when it shall apply the procedures set out in 11.9a (Emergency Procedures).

11.3 Billing and Payment Process.

The ISO will calculate for each charge the amounts payable by the relevant Scheduling Coordinator, Black Start Generator or Participating TO for each Settlement Period of the Trading Day, and the amounts payable to that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for each Settlement Period of that Trading Day and shall arrive at a net amount payable for each

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

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

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

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

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

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

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

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

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

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

be derived pursuant to Section 40.8.4.

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

30.5 [Not Used]

30.6 RMR.

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

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

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

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

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

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

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

34 REAL-TIME.

34.1 Energy Bids.

34.1.1 Energy Bid Definition.

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

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

34.1.2 Energy Bid Submission.

34.1.2.1 Real Time Market.

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

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

34.1.2.2 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

(d) recovering Operating Reserves utilized in real time;

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

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

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

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

34.2 Supplemental Energy Bids.

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

34.2.1 Identification of Supplemental Energy Bids.

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

39.3 Negative Decremental Energy Bids.

Negative decremental Energy bids into the ISO Markets less than -$30/MWh (minus thirty dollars per MWh) shall not be eligible to set any Market Clearing Price and, if Dispatched, shall be paid as bid. If the ISO Dispatches a bid below -$30/MWh, the supplier must submit a detailed breakdown of the component costs justifying the bid to the ISO and to the Federal Energy Regulatory Commission no later than seven (7) days after the end of the month in which the bid was submitted. The ISO will treat such information as confidential and will apply the procedures in Section 20.4 of this ISO Tariff with regard to requests for disclosure of such information. The ISO shall pay suppliers for amounts in excess of $-30/MWh after those amounts have been justified.

ARTICLE V – RESOURCE ADEQUACY

40 RESOURCE ADEQUACY.

40.1 Must-Offer Obligations.

This Section 40 applies to all Scheduling Coordinators representing Load Serving Entities serving retail Load within the ISO Control Area. For purposes of this Section 40 of the ISO Tariff, Load Serving Entity is defined as: (1) any entity serving retail Load under the jurisdiction of the California Public Utilities Commission (hereinafter "CPUC"), including an Electrical corporation under section 218 of the California Public Utilities Code (hereinafter "PUC"), an Electric service provider under section 218.3 of the PUC, and a Community choice aggregator under section 331.1 of the PUC (hereinafter collectively "CPUC Load Serving Entities"); and (2) all entities serving retail Load in the ISO Control Area not within the jurisdiction of the CPUC including: (i) a local publicly owned electric utility under section 9604 of the PUC; (ii) the State Water Resources Development System commonly known as the State Water Project; and (iii) any Federal entities, including but not limited to Federal Power Marketing Authorities, that serve retail Load (hereafter collectively "non-CPUC Load Serving Entities"). Load Serving Entity shall not include customer generation located on the customer's site or providing electric service through arrangements authorized by Section 218 of the PUC, if the customer generation, or the Load it serves, meets one of the following criteria: (i) it takes standby service from the electrical corporation on a commission-approved rate schedule that provides for adequate backup planning and operating reserves for the standby customer class; (ii) it is not physically interconnected to the electric transmission or distribution grid, so that if the customer generation fails, backup electricity is not supplied from the electricity grid; or (iii) there is physical assurance that the Load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation.

40.2.4 Reporting of Enforcement Actions.

To the extent that the CPUC or other Local Regulatory Authority has not adopted rules allowing public access to records or information regarding action taken for violations of its Resource Adequacy policies and rules, the Scheduling Coordinator for each Load Serving Entity serving Load in the ISO Control Area notified of a potential failure to comply by the ISO and not resolved under 40.2.3 must report to the ISO within thirty (30) days of any action taken by the appropriate Local Regulatory Authority in response to the deficiency notification.

40.2.5 Compliance with Submission Obligation.

Scheduling Coordinators representing Load Serving Entities Serving Load in the ISO Control Area that fail to provide the ISO with annual or monthly Resource Adequacy Plans as set forth in this ISO Tariff shall be subject to Section 37.6.1 of the ISO Tariff.

40.6A.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 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). 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

Energy above minimum load due to an ISO Dispatch Instruction, the Resource Adequacy Resource shall recover its Un-Recovered Minimum Load Costs as set forth in this Section and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible Resource Adequacy Resource for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from Resource Adequacy Resources that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) To the extent the Instructed Imbalance Energy payments are not sufficient to cover the generator's Minimum Load Cost as defined in Section 40.6B.3 of this ISO Tariff, the generator will also receive an uplift payment for its Un-Recovered Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the unit runs at minimum load in compliance with the Resource Adequacy offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

40.6B.2 Payments for Imbalance Energy above the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

When, on a Settlement Interval basis, a Resource Adequacy Resource's Generating Unit or System Units for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity produces a quantity of Energy above the unit's minimum operating level due to an ISO Dispatch Instruction, the Resource Adequacy Resource shall recover Un-Recovered Minimum Load Costs as set forth in Section 40.6B.1 and its bid costs, based on the ISO's instruction, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band.

40.6B.3 Payments for Imbalance Energy for the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

Resource Adequacy Resources operating at or near its operating level during a Waiver Denial Period either: (1) without a forward Schedule for its minimum operating level Energy or (2) with a Schedule to a special-purpose Demand ID for the sole purpose of Scheduling the minimum operating level Energy shall be paid its Un-Recovered Minimum Load Costs subject to eligibility as set forth in Section 40.6B.1 and not be paid an additional amount by the ISO for Energy actually delivered.

40.6B.4 Un-Recovered Minimum Load Costs.

The Un-Recovered Minimum Load Costs for each hour of Waiver Denial Period shall be calculated as the difference between: (1) a resource's Minimum Load Costs as calculated in this Section for the same Settlement Interval and (2) the Imbalance Energy payment for a resource's minimum load energy in the Settlement Interval. If the Imbalance Energy payment for minimum load energy exceeds the Minimum Load Costs, then there are no Un-Recovered Minimum Load Costs. The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: (1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.10) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Resource Adequacy Resource is not served from one of those three Service Areas; and (2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

40.6B.5 Allocation of Un-Recovered Minimum Load Costs.

For each Settlement Interval, the ISO shall determine that the Un-Recovered Minimum Load Costs for

Resource Adequacy Resources, as applicable, for each unit operating during a Waiver Denial Period are due to (1) local reliability requirements, (2) zonal requirements, or (3) Control Area-wide requirements. For each such month, the ISO shall sum the Un-Recovered Minimum Load Costs and shall allocate those costs as follows:

(1) if the Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity was operating to meet local reliability requirements, the incremental locational cost shall be allocated to the Participating TO in whose PTO Service Territory the unit is located, or, where the unit is located outside the PTO Service Territory of any Participating TO, to the Participating TO or Participating TOs whose PTO Service Territory or Territories are contiguous to the Service Area in which the Generating Unit or System Unit is located, in proportion to the benefits that each such Participating TO receives, as determined by the ISO. Where the costs allocated under this section are allocated to two or more Participating TOs, the ISO shall file the allocation under Section 205 of the Federal Power Act. For the purposes of this section, the incremental locational cost shall be the additional costs associated with committing and operating a particular unit or units to meet a local reliability requirement over the costs of a less expensive unit or units that would have been committed and operated absent the local reliability requirement. If a unit is committed in real-time for local reliability, its Un-Recovered Minimum Load costs shall be considered incremental locational costs. Costs allocated under this part (1) shall be considered Reliability Services Costs.

(2) if the Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity was operating due to Inter-Zonal Congestion, the Un-Recovered Minimum Load Costs shall be allocated on a monthly basis to each Scheduling Coordinator in the constrained Zone based on the ratio of that Scheduling Coordinator's monthly Demand to the sum of all Scheduling Coordinator's monthly Demand in that Zone;

(3) if the Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity was operating to satisfy an ISO Control Area-wide need, the ISO shall allocate the Un-Recovered Minimum Load Costs in the following way:

a. first, to the monthly absolute total of all Net Negative Uninstructed Deviation (determined for each Settlement Interval based on Final Hour-Ahead Schedules) at a per-MWh rate that shall not exceed a figure that is determined by dividing the total Un-Recovered Minimum Load Cost in that month by the sum of the minimum loads for Generating Units operating under Waiver Denial Periods in that month;

b. finally, all remaining costs not allocated per (a) shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's monthly Control Area Gross Load and Demand within California outside the ISO Control Area that is served by exports to the monthly sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators.

40.6B.6 Payment of Available Capacity under the Resource Adequacy Obligation.

Available Generation of Resource Adequacy Resources that is required to be offered to the Real Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Un-Recovered Minimum Load Cost compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period that the unit generated above minimum load in compliance with ISO Dispatch Instructions.

40.7 FERC Must-Offer Obligations.

40.7.1 Applicability.

The requirements of Section 40.7 shall apply to (a) all Participating Generators, and (b) all persons, regardless of whether the person is a "public utility" as defined in Section 201 of the Federal Power Act, that own or control one or more non-hydroelectric Generating Units or System Units or System Resources located in California from which energy or capacity is either: (i) sold through any market operated by the ISO, or (ii) transmitted over the ISO Controlled Grid. Each person described in this Section 40.7.1 is referred to in the ISO Tariff as a "FERC Must-Offer Generator." The requirements of this Section 40.7 shall apply to all non-hydroelectric Generating Units located in California that are owned or controlled by a FERC Must-Offer Generator.

40.7.2 Available Generation.

For the purposes of Section 40.7, a FERC Must-Offer Generator's "Available Generation" from a non-hydroelectric Generating Unit shall be: (a) the Generating Unit's maximum operating level adjusted for any outages or reductions in capacity reported to the ISO in accordance with Section 9.3.9 or 40.7.3 and for any limitations on the Generating Unit's operation under applicable law, including contractual obligations, which shall be reported to the ISO, (b) minus the Generating Unit's scheduled operating level as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the Generating Unit's or System Unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the FERC Must-Offer Generator's Native Load.

40.7.3 Reporting Requirements for Non-Participating Generators.

So that the ISO may determine the Available Generation of all FERC Must-Offer Generators, FERC Must-Offer Generators that are not Participating Generators shall be required to file with the ISO, for each non-hydroelectric Generating Unit located in California they own or control: (i) the Generating Unit's minimum operating level; (ii) the Generating Unit's maximum operating level; and (iii) the Generating Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch FERC Must-Offer Generators. In addition, FERC Must-Offer Generators that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 40.7, notify the ISO, as soon as practicable, of any Planned Maintenance Outages, Forced Outages, Force Majeure Event

outages or any other reductions in their maximum operating levels or Resource Adequacy Capacity during the relevant month.

40.7.4 Obligation To Offer Available Generation.

Except as set forth in Sections 40.7.5 and 40.7.6, all FERC Must-Offer Generators shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 40.7.2.

40.7.5 Submission of Bids and Applicability of the Proxy Price.

For each Operating Hour, FERC Must-Offer Generators shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 34.2. In addition, the ISO shall calculate for each gas-fired FERC Must-Offer Generator, in accordance with Section 40.10.1, a Proxy Price for Energy.

If a FERC Must-Offer Generator fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the unbid quantity of the FERC Must-Offer Generator's Available Generation will be deemed by the ISO to be bid at the FERC Must-Offer Generator's Proxy Price for that hour if: (i) the applicable Generating Unit is a gas-fired unit and (ii) the FERC Must-Offer Generator has provided the ISO with adequate data in compliance with Sections 40.7.7 and 40.7.3 for the applicable Generating Unit. For all other Generating Units owned or controlled by a FERC Must-Offer Generator, the unbid quantity of the FERC Must-Offer Generator's Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order, the ISO will insert this unbid quantity into the FERC Must-Offer Generator's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the FERC Must-Offer Generator's Available Generation.

40.7.6 FERC Must-Offer Obligation Process.

FERC Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 40.7.4 of this ISO Tariff, for one or more of their Generating Units or System Units.

All FERC Must-Offer Generators obligated under the must-offer obligation that have not submitted Day-

Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all Available Generation. If conditions permit, the ISO may, at its sole discretion, grant waivers and allow a FERC Must-Offer Generator to remove one or more Generating Units or System Units from service. In doing so, the ISO will first grant waivers to FERC Must-Offer Generators, on a non-discriminatory basis, that are not also Resource Adequacy Resources and then, if permissible, the ISO may grant waivers to Resource Adequacy Resources 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 prior to revoking the waivers of other FERC Must-Offer Generators. The ISO shall inform a FERC Must-Offer Generator that its Waiver request has been approved, disapproved or revoked, and shall provide the FERC Must-Offer Generator with the reason(s) for the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify FERC Must-Offer Generators of the ISO decisions on pending Waiver requests received no later than 10:00 a.m. (beginning of Hour Ending 11) no later than 11:30 a.m. (middle of Hour Ending 12) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m. on the following day, notify FERC Must-Offer Generators of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m. (beginning of Hour Ending 11) on the day before; (3) end Waiver Denial Periods at any time; and (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to the time a unit would be required to be on-line generating at its Pmin.

40.8 Recovery of Minimum Load Costs By FERC Must-Offer Generators.

40.8.1 Eligibility.

Except as set forth below, Generating Units shall be eligible to recover Minimum Load Costs during Waiver Denial Periods. Units from FERC Must-Offer Generators that incur Minimum Load Costs during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a FERC Must-Offer Generator has a Final Hour-Ahead Energy Schedule, the FERC Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a FERC Must-Offer Generator generating at minimum operating level in compliance with the must-offer obligation, produces a quantity of Energy that varies from its minimum operating level by more than the Tolerance Band, the FERC Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a FERC Must-Offer Generator's resource produces a quantity of Energy above minimum load due to an ISO Dispatch Instruction, the FERC Must-Offer Generator shall recover its Minimum Load Costs as set forth in this Section and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible FERC Must-Offer Generator for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from FERC Must-Offer Generators that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) The generator's Minimum Load Cost as defined in Section 40.8.4 of this ISO Tariff, the generator will also receive a payment for its Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

40.8.2 Payments for Imbalance Energy Above the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

When, on a Settlement Interval basis, a FERC Must-Offer Generator's Generating Unit produces a quantity of Energy above the Generating Unit's minimum operating level due to an ISO Dispatch Instruction, the FERC Must-Offer Generator shall recover Minimum Load Costs and its bid costs, based on the ISO's instruction, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band.

40.8.3 Payments for Imbalance Energy for the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.

A Generating Unit operating at or near its minimum operating level during a Waiver Denial Period either (1) without a forward Schedule for its minimum operating level Energy or (2) with a Schedule to a special-purpose Demand ID for the sole purpose of Scheduling the minimum operating level Energy shall be paid, in addition to being paid its Minimum Load Costs subject to eligibility as set forth in Section 40.8.1, an amount equal to the Resource Specific Settlement Interval Ex Post Price times the amount of Energy actually delivered.

40.8.4 Minimum Load Costs.

The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: (1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.10) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the FERC Must-Offer Generator is not served from one of those three Service Areas; and (2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

40.8.5 [Not Used]

40.8.6 Allocation of Minimum Load Costs.

For each Settlement Interval, the ISO shall determine that the Minimum Load Costs for each FERC Must Offer Generator unit operating during a Waiver Denial Period are due to (1) local reliability requirements, (2) zonal requirements, or (3) Control Area-wide requirements. For each such month, the ISO shall sum the Settlement Interval Minimum Load Costs and shall allocate those costs as follows:

(1) if the Generating Unit was operating to meet local reliability requirements, the incremental locational cost shall be allocated to the Participating TO in whose PTO Service Territory the Generating Unit is located, or, where the Generating Unit is located outside the PTO Service Territory of any Participating TO, to the Participating TO or Participating TOs whose PTO Service Territory or Territories are contiguous to the Service Area in which the Generating Unit is located, in proportion to the benefits that each such Participating TO receives, as determined by the ISO. Where the costs allocated under this section are allocated to two or more Participating TOs, the ISO shall file the allocation under Section 205 of the Federal Power Act. For the purposes of this section, the incremental locational cost shall be the additional costs associated with committing and operating a particular unit or units to meet a local reliability requirement over the costs of a less expensive unit or units that would have been committed and operated absent the local reliability requirement. If a unit is committed in real-time for local reliability, its Minimum Load costs shall be considered incremental locational costs. Costs allocated under this part (1) shall be considered Reliability Services Costs.

(2) if the Generating Unit was operating due to Zonal requirements, the Minimum Load Costs shall be allocated on a monthly basis to each Scheduling Coordinator in the constrained Zone based on the ratio of that Scheduling Coordinator's monthly Demand to the sum of all Scheduling Coordinator's monthly Demand in that Zone;

(3) if the Generating Unit was operating to satisfy an ISO Control Area-wide need, the ISO shall allocate the Minimum Load Costs in the following way:

a. first, to the monthly absolute total of all Net Negative Uninstructed Deviation (determined for each Settlement Interval based on Final Hour-Ahead Schedules) at a per-MWh rate that shall not exceed a figure that is determined by dividing the total Minimum Load Cost in that month by the sum of the minimum loads for Generating Units operating under Waiver Denial Periods in that month;

b. finally, all remaining costs not allocated per (a) shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's monthly Control Area Gross Load and Demand within California outside the ISO Control Area that is served by exports to the monthly sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators.

40.8.7 Payment Of Available Generation Under The FERC Must-Offer Obligation.

Available Generation that is required to be offered to the Real-Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Minimum Load Cost compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period, as defined in Section 40.8.1, that the unit generated Energy above minimum operating level in compliance with ISO Dispatch Instructions.

40.9 Criteria for Issuing Must-Offer Waivers.

The ISO shall grant waivers so as to: (1) provide sufficient on-line generating capacity to meet operating reserve requirements; and (2) account for other physical operating constraints, including Generating Unit or System Unit minimum up and down times. Subject to the exceptions for Short Start Resource Adequacy Resources as identified in this ISO Tariff, the ISO shall grant, deny or revoke waivers using a security-constrained unit commitment software application to minimize start-up and Minimum Load Costs.

40.10 Requirement of FERC Must-Offer Generators to File Heat Rate and Emissions Rate Data.

Resource Adequacy Resources and FERC Must-Offer Generators, as defined in this ISO Tariff, that own or control gas-fired Generating Units or System Units must file with the ISO and the FERC, on a confidential basis, the heat rates and emissions rates for each gas-fired Generating Unit or System Unit that they own or control. Heat rate and emissions rate data shall be provided in the format specified by the ISO as posted on the ISO Website. Heat rate data provided to comply with this requirement shall not include start-up or minimum load fuel costs. Resource Adequacy Resources and FERC Must-Offer Generators must also file periodic updates of this data upon the direction of either FERC or the ISO. The ISO will treat the information provided to the ISO in accordance with this section as confidential and will apply the procedures in Section 20.4 of this ISO Tariff with regard to requests for disclosure of such information.

40.10.1 Calculation of the Proxy Price.

The ISO shall calculate each day separate Proxy Prices for each gas-fired Generating Unit or System Unit owned or controlled by a Resource Adequacy Resource or FERC Must-Offer Generator by applying the filed heat rates for those Generating Units or System Units to a daily proxy figure for natural gas costs with an additional $6.00/MWh allowed for operations and maintenance expenses. The proxy figures for natural gas costs shall be based on the most recent data available and shall be posted on the ISO Website by 8:00 AM on the day prior to which the figures will be used for calculation of the Proxy Price.

40.11 Emissions Costs.

40.11.1 Obligation to Pay Emissions Cost Charges.

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Emissions Costs incurred by a Resource Adequacy Resource or FERC Must-Offer Generator as a direct result of an ISO Dispatch Instruction, in accordance with this Section 40. The ISO shall levy this administrative charge (the "Emissions Cost Charge") each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Emissions Cost Charges in accordance with the ISO Payments Calendar.

40.11.2 Emissions Cost Trust Account.

All Emissions Cost Charges received by the ISO shall be deposited in the Emissions Cost Trust Account. The Emissions Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.

40.11.3 Rate For the Emissions Cost Charge.

The rate at which the ISO will assess the Emissions Cost Charge shall be at the projected annual total of all Emissions Costs incurred by Resource Adequacy Resources and FERC Must-Offer Generators as a direct result of ISO Dispatch Instruction, adjusted for interest projected to be earned on the monies in the Emissions Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators for the applicable year ("Emissions Cost Demand"). The initial rate for the Emissions Cost Charge, and all subsequent rates for the Emissions Cost Charge, shall be posted on the ISO Website.

40.11.4 Adjustment of the Rate For the Emissions Cost Charge.

The ISO may adjust the rate at which the ISO will assess the Emissions Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between actual Emissions Cost Demand and projected Emissions Cost Demand;

(b) the difference, if any, between the projections of the Emissions Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions and the actual Emissions Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions as invoiced to the ISO and verified in accordance with this Section 40.11; and

(c) the difference, if any, between actual and projected interest earned on funds in the Emissions Cost Trust Account.

The adjusted rate at which the ISO will assess the Emissions Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Website at least five (5) days in advance of the date on which the new rate shall go into effect.

40.11.5 Credits and Debits of Emissions Cost Charges Collected from Scheduling Coordinators.

In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Emissions Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

40.11.6 Submission of Emissions Cost Invoices.

Scheduling Coordinators for Resource Adequacy Resources or FERC Must-Offer Generators that incur Emissions Costs as a direct result of an ISO Dispatch Instruction may submit to the ISO an invoice in the form specified on the ISO Website (the "Emissions Cost Invoice") for the recovery of such Emissions Costs. Emissions Cost Invoices shall not include any Emissions Costs specified in an RMR Contract for a unit owned or controlled by a FERC Must-Offer Generator. All Emissions Cost Invoices must include a copy of all final invoice statements from air quality districts demonstrating the Emissions Costs incurred by the applicable Generating Unit or System Unit, and such other information as the ISO may reasonably require to verify the Emissions Costs incurred as a direct result of an ISO Dispatch Instruction.

40.11.7 Payment of Emissions Cost Invoices.

The ISO shall pay Scheduling Coordinators for all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction. If the Emissions Costs indicated in the applicable air quality districts' final invoice statements include emissions produced by operation not resulting from ISO Dispatch Instructions, the ISO shall pay an amount equal to Emissions Costs multiplied by the ratio of the MWh associated with ISO Dispatch Instruction to the total MWh associated with such Emissions Costs. The ISO shall pay Emissions Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Emissions Cost Trust Account. To the extent there are insufficient funds available in Emissions Cost Trust Account in any month to pay all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction, the ISO shall make pro rata payment of such Emissions Costs and shall adjust the rate at which the ISO will assess the Emissions Cost Charge in accordance with Section 40.11.4. Any outstanding Emissions Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Emissions Costs is limited to the obligation to pay Emissions Cost Charges received. All disputes concerning payment of Emissions Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

40.12 Start-Up Costs.

40.12.1 Obligation to Pay Start-Up Cost Charges.

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Start-Up Costs incurred by a Resource Adequacy Resource or FERC Must-Offer Generator as a direct result of an ISO Dispatch Instruction, in accordance with this Section 40.12. Such Start-Up Costs shall include (1) fuel and (2) auxiliary power. The ISO shall levy this charge (the "Start-Up Cost Charge"), each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Start-Up Cost Charges in accordance with the ISO Payments Calendar.

40.12.2 Start-Up Cost Trust Account.

All Start-Up Cost Charges received by the ISO shall be deposited in the Start-Up Cost Trust Account. The Start-Up Cost Trust Account shall be an interest-bearing account separate from all other accounts maintained by the ISO, and no other funds shall be commingled in it at any time.

40.12.3 Rate For the Start-Up Cost Charge.

The rate at which the ISO will assess the Start-Up Cost Charge shall be at the projected annual total of all Start-Up Costs incurred by Resource Adequacy Resource or FERC Must-Offer Generators as a direct result of ISO Dispatch Instruction, adjusted for interest projected to be earned on the monies in the Start-Up Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area ("Start-Up Cost Demand"). The initial rate for the Start-Up Cost Charge, and all subsequent rates for the Start-Up Cost Charge, shall be posted on the ISO Website.

40.12.4 Adjustment of the Rate For the Start-Up Cost Charge.

The ISO may adjust the rate at which the ISO will assess the Start-Up Cost Charge on a monthly basis, as necessary, to reflect the net effect of the following:

(a) the difference, if any, between actual Start-Up Cost Demand and projected Start-Up Cost Demand;

(b) the difference, if any, between the projections of the Start-Up Costs incurred by FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions and the actual Start-Up Costs incurred by Resource Adequacy Resource or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions as invoiced to the ISO and verified in accordance with this Section 40.12; and

(c) the difference, if any, between actual and projected interest earned on funds in the Start-Up Cost Trust Account.

The adjusted rate at which the ISO will assess the Start-Up Cost Charge shall take effect on a prospective basis on the first day of the next calendar month. The ISO shall publish all data and calculations used by the ISO as a basis for such an adjustment on the ISO Website at least five (5) days in advance of the date on which the new rate shall go into effect.

40.12.5 Credits and Debits of Start-Up Cost Charges Collected from Scheduling Coordinators.

In addition to the surcharges or credits permitted under Section 11.6.3.3 of this ISO Tariff, the ISO may credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of Start-Up Cost Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

40.12.6 Submission of Start-Up Cost Invoices.

Scheduling Coordinators for Resource Adequacy Resources or FERC Must-Offer Generators that incur Start-Up Costs as a direct result of an ISO Dispatch Instruction or if the ISO revokes a waiver from compliance with the FERC must-offer obligation while the unit is off-line in accordance with Section 40.6A.6 or 40.7.6 of this ISO Tariff, and Scheduling Coordinators for Generating Units or System Units operating under Condition 2 of the relevant RMR Contract which are called out-of-market in accordance with Section 11.2.4.2 of this ISO Tariff may submit to the ISO an invoice in the form specified on the ISO Website (the "Start-Up Cost Invoice") for the recovery of such Start-Up Costs. Such Start-Up Costs shall not exceed the costs which would be incurred within the start-up time for a unit specified in Schedule 1 of the Participating Generator Agreement. Start-Up Cost Invoices shall use the applicable proxy figure for natural gas costs as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Resource Adequacy Resource or FERC Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas. Start-Up Cost Invoices shall specify the amount of auxiliary power used during the start-up and the actual price paid for that power. Start-Up Cost Invoices shall not include any Start-Up Costs specified in an RMR Contract for a unit owned or controlled by a FERC Must-Offer Generator.

40.12.7 Payment of Start-Up Cost Invoices.

The ISO shall pay Scheduling Coordinators for all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction. The ISO shall pay such Start-Up Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Start-Up Cost Trust Account. To the extent there are insufficient funds available in the Start-Up Cost Trust Account in any month to pay all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction, the ISO shall make pro rata payment of such Start-Up Costs and shall adjust the rate at which the ISO will assess the Start-Up Cost Charge in accordance with Section 40.12.4. Any outstanding Start-Up Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay

Start-Up Costs is limited to the obligation to pay Start-Up Cost Charges received. All disputes concerning payment of Start-Up Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

40.13 ISO Default Qualifying Capacity Criteria.

40.13.1 Applicability.

The criteria in Section 40.13 shall apply only where a Local Regulatory Authority does not establish criteria to determine the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity for such eligible resource types.

40.13.2 Nuclear and Thermal.

Nuclear and thermal units, other than Qualifying Facilities ("QFs") with effective contracts under the Public Utility Regulatory Policies Act addressed in Section 40.13.8 below, must be a Participating Generator or a System Unit. The Qualifying Capacity of nuclear and thermal units, other than Qualifying Facilities addressed in Section 40.13.8, will be based on net dependable capacity defined by North American Electric Reliability Council ("NERC") Generating Availability Data System ("GADS") information.

40.13.3 Hydro.

Hydro units, other than QFs with contracts under the Public Utility Regulatory Policies Act, must be either Participating Generators or System Units. The Qualifying Capacity of a pond or pumped storage hydro unit, other than a QF, will be determined based on net dependable capacity defined by NERC GADS minus variable head de-rate based on an average dry year reservoir level. The Qualifying Capacity of a pond or pumped storage hydro unit that is a QF will be determined based on historic performance during the Standard Offer 1 peak hours of noon to 6:00 p.m., using a three-year rolling average.

The Qualifying Capacity of all run-of-river hydro units, including QFs, will be based on net dependable capacity defined by NERC GADS minus an average dry year conveyance flow, stream flow, or canal head de-rate. As used in this section, average dry year reflects a one-in-five year dry hydro scenario (for example, using the 4th driest year from the last 20 years on record).

40.13.4 Unit-Specific Contracts.

Unit-specific contracts with Participating Generators or System Units will qualify as Resource Adequacy capacity subject to the verification that the total MW quantity of all contracts from a specific unit do not exceed the total Net Qualifying Capacity (MW) consistent with the Net Qualifying Capacity determination for that unit.

40.13.5 Contracts with Liquidated Damage Provisions.

Firm energy contracts with liquidated damages provisions, as generally reflected in Service Schedule C of the Western Systems Power Pool Agreement or the Firm LD product of the Edison Electric Institute pro forma agreement, or any other similar firm energy contract that does not require the seller to source the energy from a particular unit, and specifies a delivery point internal to the ISO Control Area entered into before October 27, 2005 shall be eligible to count as Qualifying Capacity until the end of 2008. A Scheduling Coordinator, however, cannot have more than 75% of its portfolio of Qualifying Capacity met by contracts with liquidated damage provisions for 2006. This percentage will be reduced to 50% for 2007 and 25% for 2008.

40.13.6 Wind and Solar.

As used in this Section, wind units are those wind Generating Units without backup sources of generation and solar units are those solar Generating Units without backup sources of generation. Wind and Solar units, other than QFs with effective contracts under the Public Utility Regulatory Policies Act, must be participants in the ISO's Participating Intermittent Resource Program ("PIRP").

The Qualifying Capacity of all wind or solar units, including QFs, will be based on their monthly historic performance during the Standard Offer 1 peak hours of noon to 6:00 p.m., using a three-year rolling average. New wind and solar generators which do not have three years of historic performance data will be assigned a default Qualifying Capacity for each year of the missing historical performance as follows: the Qualifying Capacity of another solar or wind generator with historic data located in the same weather regime with similar technology adjusted for the nameplate capacity ratio of the new generator and the similarly situated proxy generator. The supporting data and the sample Qualifying Capacity calculation will be submitted to the ISO for approval as part of the facilities PIRP program application.

The default Qualifying Capacity values will be replaced on a year by year basis with actual performance data as the data becomes available to form a three year rolling average.

40.13.7 Geothermal.

Geothermal units, other than QFs addressed in Section 40.13.8, must be Participating Generators or System Units. The Qualifying Capacity of geothermal units, other than QFs addressed in Section 40.13.8, will be based on NERC GAD net dependable capacity minus a de-rate for steam field degradation.

40.13.8 Treatment of Qualifying Capacity for QFs.

QFs must be Participating Generators (signed a Participating Generator or QF Participating Generator Agreement) or System Units, unless they have a PURPA contract. Except for hydro, wind, and solar QFs addressed pursuant to Sections 40.13.3 and 40.13.6 above, the Qualifying Capacity of QFs under PURPA contracts, will be based on historic monthly generation output during Standard Offer 1 peak hours of noon to 6:00 p.m. (net behind the meter loads) during a three-year rolling average.

40.13.9 Participating Load Resources.

The Qualifying Capacity of Participating Load shall be the average reduction in demand for over a three-year period on a per dispatch basis or, if the Participating Load does not have three years of performance history, based on comparable evaluation data using similar programs. Participating Load resources must be available at least 48 hours and if the Participating Load can only be dispatched for a maximum of two hours per event, than only 0.89% of a Scheduling Coordinator's portfolio may be made up of such Participating Load.

40.13.10 Jointly-Owned Facilities.

A jointly-owned facility must be either a Participating Generator or a System Unit. The Qualifying Capacity for the entire facility will be determined based on the type of resource as described elsewhere in this Section. In addition, the Scheduling Coordinator must provide the ISO with a demonstration of its entitlement to the output of the jointly-owned facility's Qualified Capacity and an explanation of how that entitlement may change if the facility's output is restricted.

constraints may be imposed beyond those explicitly stated in the plan.

41 Procurement of RMR.

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

42.1 Generation Planning Reserve Criteria.

Generation planning reserve criteria shall be met as follows:

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

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

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

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

42.1.5 Notwithstanding the foregoing, if the ISO concludes that it may be unable to comply with the Applicable Reliability Criteria, the ISO shall, acting in accordance with Good Utility Practice, take such steps as it considers to be necessary to ensure compliance, including the negotiation of contracts through processes other than competitive solicitations. The steps can include the negotiation of contracts for Ancillary Services on a real time basis. If the ISO is unable to obtain such Ancillary Services from within the ISO Controlled Grid, the ISO may solicit Ancillary Services from other Control Areas on a real-time basis.

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

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

42.1.8 Except where and to the extent that such costs are recovered from Scheduling Coordinators pursuant to Section 8, and except as provided in Section 42.1.9, all costs incurred by the ISO in any hour pursuant to any contract entered into under this Section 42.1 shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (including exports) bears to the total metered hourly Demand (including exports) served in that hour.

42.1.9 Costs incurred by the ISO pursuant to any contract entered into under this Section 42.1 for resources to meet any portion of the anticipated difference between forward schedules and the real-time deviations from those schedules shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator's obligation for deviation Replacement

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

Replacement Reserve in that hour.

	States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Participating TO.
Eligible Intermittent Resource	A Generating Unit that is powered solely by 1) wind, 2) solar energy, or 3) hydroelectric potential derived from small conduit water distribution facilities that do not have storage capability.
Emissions Cost Charge	The charge determined in accordance with Section 40.11.
Emissions Cost Demand	The level of Demand specified in Section 40.11.3.
Emissions Cost Invoice	The invoice submitted to the ISO in accordance with Section 40.11.6.
Emissions Cost Trust Account	The trust account established in accordance with Section 40.11.2.
Emissions Costs	The mitigation fees, excluding capital costs, assessed against a Generating Unit by a state or federal agency, including air quality districts, for exceeding applicable NOx emissions limitations.
EMS (Energy Management System)	A computer control system used by electric utility dispatchers to monitor the real-time performance of the various elements of an electric system and to control Generation and transmission facilities.
Encumbrance	A legal restriction or covenant binding on a Participating TO that affects the operation of any transmission lines or associated facilities and which the ISO needs to take into account in exercising Operational Control over such transmission lines or associated facilities if the Participating TO is not to risk incurring significant liability. Encumbrances shall include Existing Contracts and may include: (1) other legal restrictions or covenants meeting the definition of Encumbrance and arising under other arrangements entered into before the ISO Operations Date, if any; and (2) legal restrictions or covenants meeting the definition of Encumbrance and arising under a contract or other arrangement entered into after the ISO Operations Date.
End-Use Customer or	A consumer of electric power who consumes such power to satisfy a

modifications that will be required to provide needed services.

Facility Study Agreement	An agreement between a Participating TO and either a Market Participant, Project Sponsor, or identified principal beneficiaries pursuant to which the Market Participants, Project Sponsor, and identified principal beneficiaries agree to reimburse the Participating TO for the cost of a Facility Study.
Fed-Wire	The Federal Reserve Transfer System for electronic funds transfer.
FERC	The Federal Energy Regulatory Commission or its successor.
FERC Annual Charges	Those charges assessed against a public utility by the FERC pursuant to 18 C.F.R. § 382.201 and any related statutes or regulations, as they may be amended from time to time.
FERC Annual Charge Recovery Rate	The rate to be paid by Scheduling Coordinators for recovery of FERC Annual Charges assessed against the ISO for transactions on the ISO Controlled Grid.
FERC Annual Charge Trust Account	An account to be established by the ISO for the purpose of maintaining funds collected from Scheduling Coordinators for FERC Annual Charges and disbursing such funds to the FERC.
FERC Must-Offer Generator	All entities defined by Section 40.7.1 of this ISO Tariff.
Final Approval	A statement of consent by the ISO Control Center to initiate a scheduled Outage.
Final Day-Ahead Schedule	The Day-Ahead Schedule which has been approved as feasible and consistent with all other Schedules by the ISO based upon the ISO's Day-Ahead Congestion Management procedures.
Final Hour-Ahead Schedule	The Hour-Ahead Schedule of Generation and Demand that has been approved by the ISO as feasible and consistent with all other Schedules based on the ISO's Hour-Ahead Congestion Management procedures.
Final Invoice	The invoice due from a RMR Owner to the ISO at termination of the RMR Contract.
Final Schedule	A Schedule developed by the ISO following receipt of a Revised Schedule from a Scheduling Coordinator.

Financial Security	Any of the types of financial instruments listed in Section 12 of the ISO Tariff that are posted by a Market Participant or FTR Bidder.
Financial Security Amount	The level of Financial Security posted in accordance with Section 12 of the ISO Tariff by a Market Participant or FTR Bidder.
Final Settlement Statement	The restatement or recalculation of the Preliminary Settlement Statement by the ISO following the issue of that Preliminary Settlement Statement.
Forbidden Operating	The operating region of a resource wherein the resource cannot

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.
Large Generating Facility	A Generating Facility having a Generating Facility Capacity of more than 20 MW.
Line Loss Correction Factor	The line loss correction factor as set forth in the Technical Specifications.
Load	An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires.
Load-Serving Entity (LSE)	Any entity (or the duly designated agent of such an entity, 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 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 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.
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

	from one component necessarily causes Energy production from other components; iii) the operational arrangement of related multiple generating components determines the overall physical efficiency of the combined output of all components; iv) the level of coordination required to schedule individual generating components would cause the ISO to incur scheduling costs far in excess of the benefits of having scheduled such individual components separately; or v) metered output is available only for the combined output of related multiple generating components and separate generating component metering is either impractical or economically inefficient.
Planning Reserve Margin	A Planning Reserve Margin shall be that quantity or percentage of capacity in MWs that exceeds the Demand Forecast set forth in Section 40.3 as provided for in Section 40.4 of this ISO Tariff.
PMS (Power Management System)	The ISO computer control system used to monitor the real-time performance of the various elements of the ISO Controlled Grid, control Generation, and perform operational power flow studies.
Point of Change of Ownership	The point, as set forth in Part A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Participating TO's Interconnection Facilities.
Point of Interconnection	The point, as set forth in Part A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the ISO Controlled Grid.
Power Flow Model	The computer software used by the ISO to model the voltages, power injections and power flows on the ISO Controlled Grid and determine the expected Transmission Losses and Generation Meter Multipliers.
Power System Stabilizers (PSS)	An electronic control system applied on a Generating Unit that helps to damp out dynamic oscillations on a power system. The PSS senses Generator variables, such as voltage, current and shaft speed, processes this information and sends control signals to the Generator voltage regulator.

Preferred Day-Ahead Schedule	A Scheduling Coordinator's Preferred Schedule for the ISO Day-Ahead scheduling process.
Preferred Hour-Ahead Schedule	A Scheduling Coordinator's Preferred Schedule for the ISO Hour-Ahead scheduling process.

Preferred Schedule	The initial Schedule produced by a Scheduling Coordinator that represents its preferred mix of Generation to meet its Demand. For each Generator, the Schedule will include the quantity of output, details of any Adjustment Bids, and the location of the Generator. For each Load, the Schedule will include the quantity of consumption, details of any Adjustment Bids, and the location of the Load. The Schedule will also specify quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators. The Preferred Schedule will be balanced with respect to Generation, Transmission Losses, Load and trades between Scheduling Coordinators.
Preliminary Settlement Statement	The initial statement issued by the ISO of the calculation of the Settlements and allocation of the charges in respect of all Settlement Periods covered by the period to which it relates.
Price Overlap	The price range of bids for Supplemental Energy or Energy associated with Ancillary Services bids for any Dispatch Interval that includes decremental and incremental Energy Bids where the price of the decremental Energy Bids exceeds the price of the incremental Energy Bids.
Primary ISO Control Center	The ISO Control Center located in Folsom, California.
Project Sponsor	A Market Participant or group of Market Participants or a Participating TO that proposes the construction of a transmission addition or upgrade in accordance with Section 24 of the ISO Tariff.
Proposal for Installation	A written proposal submitted by an ISO Metered Entity to the ISO describing a proposal for the installation of additional Metering Facilities.
Proxy Price	The value determined for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator in accordance with Section 40.10.1.
PTO Service Territory	The area in which an IOU, a Local Public Owned Electric Utility, or federal power marketing administration that has turned over its transmission facilities and/or Entitlements to ISO Operational Control is obligated to provided electric service to Load. A PTO

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.

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.

Reactive Power Control Generation or other equipment needed to maintain acceptable voltage levels on the ISO Controlled Grid and to meet reactive capacity requirements at points of interconnection on the ISO Controlled Grid.

Real Time Market The competitive generation market controlled and coordinated by the ISO for arranging real-time Imbalance Energy.

Redispatch The readjustment of scheduled Generation or Demand side management measures, to relieve Congestion or manage Energy imbalances.

Registered Data	Those items of technical data and operating characteristics relating to Generation, transmission or distribution facilities which are identified to the owners of such facilities as being information, supplied in accordance with the ISO Tariff, to assist the ISO to maintain reliability of the ISO Controlled Grid and to

	are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided under an RMR Contract (Section 30.6.1.2), local out-of-market dispatch calls (Section 11.2.4.2.1) and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section 40.8.6)
Remote Self-Supply	Positive Net Output from generating resources in the Station Power Portfolio that is deemed to have self-supplied Station Power load of other Generating Units in the Station Power Portfolio during the Netting Period, where such self-supply requires use of the ISO Controlled Grid.
REMnet	The Wide Area Network through which the ISO acquires Meter Data.
Replacement Reserve	Generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and Ramping to a specified operating level within a sixty (60) minute period, the output of which can be continuously maintained for a two hour period. Also, Curtailable Demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours.
Resource Adequacy	The program that ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability.
Resource Adequacy Capacity	The capacity of a Resource Adequacy Resource listed on a Resource Adequacy Plan and a Supply Plan.
Resource Adequacy Plan	A submission by a Scheduling Coordinator for a Load Serving Entity serving Load in the ISO Control Area in order to satisfy the requirements of Section 40 of this ISO Tariff.

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

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

Short Start Generating Units that that have a cycle time less than five hours (Start-Up Time plus Minimum Run Time is less than five hours) have a Start Up Time less than two hours, and that can be fully optimized with respect to this cycle time.

Site Control Documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Scheduling and Logging system for the ISO of California (SLIC) A logging application that allows Market Participants to notify the ISO when a unit's properties change due to physical problems. Users can modify the maximum and minimum output of a unit, as well as the ramping capability of the unit.

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

Spinning Reserve The portion of unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and that is capable of running for at least two hours.

Stand Alone Network Upgrades Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the ISO Controlled Grid or Affected Systems during their construction. The Participating TO, the ISO, and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Standard Large Generator Interconnection Agreement.

Standard Large Generator Interconnection Agreement (LGIA)	The form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility.
Standard Large Generator Interconnection	The ISO Protocol that sets forth the interconnection procedures applicable to an Interconnection Request pertaining to a Large

Procedures (LGIP)	Generating Facility that is included in the ISO Tariff.
Standard Ramp (-ing)	A ramp calculated from two consecutive Final Hour Ahead Schedules that results in a straight trajectory between 10 minutes before the start of an operating hour to 10 minutes after the start of the operating hour
Standby Rate	A rate assessed a Standby Service Customer by the Participating TO that also provides retail electric service, as approved by the Local Regulatory Authority, or FERC, as applicable, for Standby Service which compensates the Participating TO, among other things, for costs of High Voltage Transmission Facilities.
Standby Service	Service provided by a Participating TO that also provides retail electric service, which allows a Standby Service Customer, among other things, access to High Voltage Transmission Facilities for the delivery of backup power on an instantaneous basis to ensure that Energy may be reliably delivered to the Standby Service Customer in the event of an outage of a Generating Unit serving the customer's Load.
Standby Service Customer	A retail End-Use Customer of a Participating TO that also provides retail electric service that receives Standby Service and pays a Standby Rate.
Standby Transmission Revenue	The transmission revenues, with respect to cost of both High Voltage Transmission Facilities and Low Voltage Transmission Facilities, collected directly from Standby Service Customers through charges for Standby Service.
Start-Up Cost Charge	The charge determined in accordance with Section 40.12.
Start-Up Cost Demand	The level of Demand specified in Section 40.12.3.
Start-Up Cost Invoice	The invoice submitted to the ISO in accordance with Section 40.12.6.
Start-Up Cost Trust Account	The trust account established in accordance with Section 40.12.2.
Start-Up Costs	The cost incurred by a particular Generating Unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchronized to the grid, whichever is later, until the time the generating unit reaches its minimum operating level. Start-Up Costs are determined as the sum of (1) the cost of auxiliary power used during the start-up and (2) the number that is determined multiplying the actual amount of fuel consumed by the proxy gas price

	an hour before the commencement of the Settlement Period.
Supply	The rate at which Energy is delivered to the ISO Controlled Grid measured in units of watts or standard multiples thereof, e.g., 1,000W=1 KW; 1,000 KW = 1MW, etc.
Supply Plan	A submission by a Scheduling Coordinator for a Resource Adequacy Resource in order to satisfy the requirements of Section 40 of this ISO Tariff.
System Emergency	Conditions beyond the normal control of the ISO that affect the ability of the ISO Control Area to function normally including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading Outages or to restore system operation to meet the minimum operating reliability criteria.
System Planning Studies	Reports summarizing studies performed to assess the adequacy of the ISO Controlled Grid as regards conformance to Reliability Criteria.
System Reliability	A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency.
System Resource	A group of resources, single resource, or a portion of a resource located outside of the ISO Control Area, or an allocated portion of a Control Area's portfolio of generating resources that are directly responsive to that Control Area's Automatic Generation Control (AGC) capable of providing Energy and/or Ancillary Services to the ISO Controlled Grid.
System Unit	One or more individual Generating Units and/or Loads within a Metered Subsystem controlled so as to simulate a single resource with specified performance characteristics, as mutually determined and agreed to by the MSS Operator and the ISO. The Generating Units and/or Loads making up a System Unit must be in close physical proximity to each other such that the operation of the resources comprising the System Unit does not result in significant differences in flows on the ISO Controlled Grid.
TAC Area	A portion of the ISO Controlled Grid with respect to which Participating TOs' High Voltage Transmission Revenue Requirements are recovered through a High Voltage Access Charge. TAC Areas are listed in Schedule 3 of Appendix F.

Take-Out Point	The metering points at which a Scheduling Coordinator Metered Entity or ISO Metered Entity takes delivery of Energy.
Tax Exempt Debt	Municipal Tax Exempt Debt or Local Furnishing Bonds.

Transmission Ownership Rights	A non-Participating TO ownership or joint ownership right to transmission facilities within the ISO Control Area that has not executed the Transmission Control Agreement and the transmission facilities are not incorporated into the ISO Controlled Grid.
Transmission Revenue Credit	For an Original Participating TO, the proceeds received from the ISO for Wheeling service, FTR auction revenue and Usage Charges, plus the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the ISO's rules and protocols. For a New Participating TO during the 10-year transition period described in Section 4 of Schedule 3 of Appendix F, the proceeds received from the ISO for Wheeling service and Net FTR Revenue, plus the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the ISO's rules and protocols. After the 10-year transition period, the New Participating TO Transmission Revenue Credit shall be calculated the same as the Transmission Revenue Credit for the Original Participating TO.
TRBA (Transmission Revenue Balancing Account)	A mechanism to be established by each Participating TO which will ensure that all Transmission Revenue Credits and other credits specified in Sections 6 and 8 of Appendix F, Schedule 3, flow through to transmission customers.
RR (Transmission Revenue Requirement)	The TRR is the total annual authorized revenue requirements associated with transmission facilities and Entitlements turned over to the Operational Control of the ISO by a Participating TO. The costs of any transmission facility turned over to the Operational Control of the ISO shall be fully included in the Participating TO's TRR. The TRR includes the costs of transmission facilities and Entitlements and deducts Transmission Revenue Credits and credits for Standby Transmission Revenue and the transmission revenue expected to be actually received by the Participating TO for Existing Rights and Converted Rights.
Trial Operation	The period during which Interconnection Customer is engaged in on-

Energy	instructed by the ISO or which the ISO Tariff provides will be paid at the price for Uninstructed Imbalance Energy.
Unit Commitment	The process of determining which Generating Units will be committed (started) to meet Demand and provide Ancillary Services in the near future (e.g., the next Trading Day).
Un-Recovered Minimum Load Cost	The Un-Recovered Minimum Load Cost for each hour of Waiver Denial Period shall be calculated as the difference between: (1) a resource's Minimum Load Costs as calculated in this Section for the same Settlement Interval and (2) the Imbalance Energy payment for a resource's minimum load energy in the Settlement Interval.
Unsecured Credit Limit	The level of credit established for a Market Participant or FTR Bidder that is not secured by any form of Financial Security, as provided for in Section 12 of the ISO Tariff.
Usage Charge	The amount of money, per 1 kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific Congested Inter-Zonal Interface during a given hour.
Validation, Estimation and Editing (VEE)	Applies to Meter Data directly acquired by the ISO. Validation is the process of checking the data to ensure that it is contiguous, within pre-defined limits and has not been flagged by the meter. Estimation and Editing is the process of replacing or making complete Meter Data by using data from redundant meters, schedules, PMS or, if necessary, statistical estimation.
Value Added Network (VAN)	A data communications service provider that provides, stores and forwards electronic data delivery services within its network and to subscribers on other VANs. The data is mostly EDI type messages.
Voltage Limits	For all substation busses, the normal and post-contingency Voltage Limits (kV). The bandwidth for normal Voltage Limits must fall within the bandwidth of the post-contingency Voltage Limits. Special voltage limitations for abnormal operating conditions such as heavy or light Demand may be specified.
Voltage Support	Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or System Emergency conditions.
Waiver Denial Period	The period determined in accordance with Section 40.7.6.

Warning Notice	A Notice issued by the ISO when the operating requirements for the ISO Controlled Grid are not met in the Hour-Ahead Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Supplemental Energy available to the ISO does not satisfy the Applicable Reliability Criteria.
Weekly Peak Demand Forecast	Demand Forecast of the highest Hourly Demand in any hour in a period beginning at the start of the hour ending 0100 on Sunday and ending at the end of the hour ending 2400 the following Saturday, in MW.

4.3.3 for the provision of an Ancillary Service or submit a schedule for the self provision of an Ancillary Service unless the Scheduling Coordinator serving that Participating Generator is in possession of a current certificate pursuant to Sections 8.4 and 8.10 of the ISO Tariff.

4.4 Obligations relating to Major Incidents

4.4.1 Major Incident Reports. The Participating Generator shall promptly provide such information as the ISO may reasonably request in relation to major incidents, in accordance with Section 4.6.7.3 of the ISO Tariff.

4.5 Dispatch and Curtailment. The ISO shall only dispatch or curtail a Net Scheduled QF of the Participating Generator: (a) to the extent the Participating Generator bids Energy or Ancillary Services from the Net Scheduled QF into the ISO's markets or the Energy is otherwise available to the ISO under Section 40.7.4 of the ISO Tariff; or (b) if the ISO must dispatch or curtail the Net Scheduled QF in order to respond to an existing or imminent System Emergency or condition that would compromise ISO Control Area integrity or reliability as provided in Sections 7, 7.3.1, and 11.2.4.2.1 of the ISO Tariff.

4.6 Information to Be Provided by Participating Generator. The Participating Generator shall provide to the ISO (a) a copy of the FERC order providing Qualifying Facility status to the Net Scheduled QF listed in Schedule 1, (b) a copy of any existing power purchase agreement with a UDC for the Net Scheduled QF listed in Schedule 1, and (c) a copy or a summary of the primary terms of any agreement for standby service with a UDC or MSS Operator. The Participating Generator shall notify the ISO promptly of any change in the status of any of the foregoing.

ARTICLE V

PENALTIES AND SANCTIONS

5.1 Penalties. If the Participating Generator fails to comply with any provisions of this Agreement, the ISO shall be entitled to impose penalties and sanctions on the Participating Generator. No penalties or sanctions may be imposed under this Agreement unless a Schedule providing for such penalties or sanctions has first been filed with and made effective by FERC. Nothing in the Agreement, with the exception of the provisions relating to ADR, shall be construed as waiving the rights of the Participating Generator to oppose or protest any penalty proposed by the ISO to the FERC or the specific imposition by the ISO of any FERC-approved penalty on the Participating Generator.

5.2 Corrective Measures. If the Participating Generator fails to meet or maintain the requirements set forth in this Agreement and/or in the ISO Tariff as limited by the provisions of this Agreement, the ISO shall be permitted to take any of the measures, contained or referenced in the ISO Tariff, which the ISO deems to be necessary to correct the situation.

D 2.6.1 Tolerance Band and Performance Check

The ISO shall determine the Tolerance Band for each Settlement Interval *o* for PGA resources and dynamically scheduled System Resources based on the data from the Master File as follows:

$TOLERANCE\_BAND_{i,h,o}$ = **Error! Objects cannot be created from editing field codes.**

where,

FIX_LIM is a fixed MW limit and is initially equal to 5 MW.

TOL_PERCENT is a fixed percentage and is initially equal to 3%.$Pmax_i$ is the maximum operating capacity in MW of resource *i* specified in the Master File.

The ISO shall determine the Tolerance Band for each Settlement Interval o *for PLA resources as follows:*

$TOLERANCE\_BAND_{i,h,o}$ = **Error! Objects cannot be created from editing field codes.**

where $HAfin_{i,h}$ *is the* Final Hour Ahead Energy Schedule.

Resources must operate within their relevant Tolerance Band in order to receive any above-Ex Post Price payments. The ISO shall determine the performance status of the resource for each Settlement Interval o. A resource shall have met its performance requirement if its $UIE_{i,h,o}$ is within its relevant Tolerance Band. A resource meeting its performance requirement in Settlement Interval o will have a $PERF\_STAT_{i,h,o} = 1$. A resource that has not met its performance requirement in Settlement Interval *o* will have a $PERF\_STAT_{i,h,o} = 0$.

Must-offer resources that produce a quantity of Energy above Minimum Load due to an ISO Dispatch Instruction during a Waiver Denial Period are not subject to the Tolerance Band requirement for purposes of receiving Minimum Load Cost Compensation, as defined in Section 40.8. Accordingly, the $PERF\_STAT_{i,h,o}$ for eligible must-offer resources, as defined in Section 40.8, shall be set to 1, irrespective of deviations outside of the Tolerance Band, for the purpose of determining eligibility for Minimum Load Cost Compensation during a Waiver Denial Period. The Tolerance Band shall be used to apply UDP during a Waiver Denial Period.

Non-dynamically scheduled System Resources do not have a Tolerance Band. Non-Participating Load Agreement (PLA) load resources are not subject to the performance requirement.

D 2.6.2 Unrecovered Costs Neutrality Allocation

For each Settlement Interval *o*, the total Unrecovered Costs for Trade Day *d* shall be allocated pro-rata to each Scheduling Coordinator *g* based on its Metered Demand, calculated as follows:

$UDP\_POS\_AMT_{i,o,h}$ or $UDP\_NEG\_AMT_{i,o,h}$ are the penalty amounts in Dollars for either an aggregated or individual resource *i* for Settlement Interval *o* of hour *h*.

The ISO will not calculate UDP settlement amounts for Settlement Intervals when the corresponding Zonal Settlement Interval Ex Post Price is negative or zero.

For an MSS that has elected to follow its own Load, the Scheduling Coordinator for the MSS Operator will be assessed the Uninstructed Deviation Penalty charges based on the Deviation Band and Deviation Price in Section 4.9.9.2 of the ISO Tariff.

D 2.9 Minimum Load Cost Compensation

The ISO shall calculate a Must-Offer Generator's Minimum Load Cost Compensation (MLCC), pursuant to section 40.8.1 of the ISO Tariff, as the Minimum Load Cost for each resource *i* during Settlement Interval *o* of hour *h*, as defined in section 40.8.4 of the ISO Tariff.

D 3 Meaning of terms in the formulae

D 3.1 [Not Used]

D 3.2 $COST\_AT\_STLMT\_PRICE_{i,h,o}$ - $/MWh

The sum of all dollar amounts from each dispatched bid segment for Energy quantities settled at the Resource-Specific Ex Post Price, for resource i during Settlement Interval o of hour h, and limited to those bid segments with Energy Bid prices below the Maximum Bid Level.

D 3.3 $BID\_COST_{i,h,o}$ - $/MWh

The sum of all dollar amounts from each dispatched bid portion of Energy quantities settled at the maximum of either the corresponding Energy Bid price for those bids with Energy Bid prices below the Maximum Bid Level or the Bid Floor, for resource i during Settlement Interval o during hour h.

D 3.4 $PRE\_DISP\_ABC\_BQ_{i,h,o}$ - MWh

The pre-dispatched Energy from all Energy Bids with any Energy Bid price above the Maximum Bid Level, for resource i during Settlement Interval o during hour h.

D 3.5 $IIE\_PREDISPATCH\_FOR\_SEGMENT_{i,h,o,k,m}$ - MWh

The pre-dispatched Energy for resource i during Dispatch Interval k of Settlement Interval o of hour h for bid segment m.

D 3.6 [Not Used]

D 3.6.1 [Not Used]

D 3.6.2 [Not Used]

D 3.6.3 [Not Used]

CERTIFICATE OF SERVICE

I hereby certify that I have, this 12th day of June 2006, caused to be served a copy of the forgoing document upon all parties listed on the official service list compiled by the Secretary of the Federal Energy Regulatory Commission in this proceeding.

Grant Rosenblum/DK

Grant Rosenblum