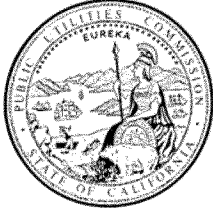


Docket: : R.07-05-025  
Exhibit Number :  
Commissioner : Michael Peevey  
Admin. Law Judge : Thomas Pulsifer  
DRA Witness : Ke Hao Ouyang



**DIVISION OF RATEPAYER ADVOCATES  
CALIFORNIA PUBLIC UTILITIES COMMISSION**

**TESTIMONY ON THE METHODOLOGY FOR  
CALCULATING DEPARTING LOAD NON-  
BYPASSABLE CHARGES, DIRECT ACCESS  
SWITCHING RULES, ELECTRIC SERVICE  
PROVIDER FINANCIAL SECURITY REQUIREMENT  
AND TRANSITIONAL BUNDLED SERVICE RATE**

**R.07-05-025**

San Francisco, California  
January 31, 2011

## TABLE OF CONTENTS

<b>I.</b>	<b>INTRODUCTION .....</b>	<b>1</b>
<b>II.</b>	<b>SUMMARY OF RECOMMENDATIONS.....</b>	<b>1</b>
<b>III.</b>	<b>DISCUSSION.....</b>	<b>2</b>
<b>PART 1:</b>	<b>POWER CHARGE INDIFFERENCE ADJUSTMENT .....</b>	<b>2</b>
<b>A.</b>	<b>ADJUST THE MARKET PRICE BENCHMARK TO CAPTURE THE VALUE     OF RENEWABLE PORTFOLIO STANDARD ELIGIBLE RESOURCES .....</b>	<b>2</b>
<b>1.</b>	<b>Value of Non-RPS Eligible Resources .....</b>	<b>3</b>
<b>2.</b>	<b>Value of RPS Eligible Resources.....</b>	<b>4</b>
<b>B.</b>	<b>REPLACE FIXED RESOURCE ADEQUACY/CAPACITY ADDERS WITH     CAPACITY COSTS.....</b>	<b>5</b>
<b>C.</b>	<b>REMOVE LOAD RELATED CAISO COSTS FROM TOTAL PORTFOLIO     COSTS .....</b>	<b>6</b>
<b>D.</b>	<b>SHORT TERM ENERGY MARKET TRANSACTIONS .....</b>	<b>6</b>
<b>E.</b>	<b>LOAD PROFILE WEIGHING OF THE MARKET PRICE BENCHMARK.....</b>	<b>7</b>
<b>F.</b>	<b>CONTINUOUS DIRECT ACCESS CUSTOMERS.....</b>	<b>9</b>
<b>PART 2:</b>	<b>ESP FINANCIAL SECURITY REQUIREMENT.....</b>	<b>10</b>
<b>PART 3:</b>	<b>DIRECT ACCESS SWITCHING RULES.....</b>	<b>11</b>
<b>PART 4:</b>	<b>TRANSITIONAL BUNDLED SERVICE RATE .....</b>	<b>12</b>
<b>APPENDIX A – QUALIFICATIONS AND PREPARED TESTIMONY OF     KE HAO OUYANG</b>		
<b>CERTIFICATE OF SERVICE</b>		

1 **I. INTRODUCTION**

2 In accordance with the Assigned Commissioner’s Ruling Adopting  
3 Amended Scoping Memo and Schedule (ASM) issued on November 22, 2011, and  
4 per the Administrative Law Judge Thomas Pulsifer’s Ruling Amending Procedural  
5 Schedule issued on January 7, 2011, the Division of Ratepayer Advocates (DRA)  
6 submits this testimony on the methodology for calculating departing load non-  
7 bypassable charges and other Direct Access (DA) Phase III issues pertaining to  
8 DA switching rules, minimum stay provisions, transitional bundled service (TBS)  
9 rates and electric service provider (ESP) financial security requirements.

10 In considering the proposed revisions to the existing rules, DRA  
11 recommends the Commission keep in mind the goal of adopting a framework that  
12 maintains bundled customer indifference when load departs. Ideally, this  
13 framework should be both accurate and transparent, and be based on publicly  
14 available information whenever possible. However, there is a tradeoff between  
15 accuracy and transparency; the most accurate and up-to-date information is not  
16 always publicly available due to confidentiality concerns. DRA’s  
17 recommendation are based on what it believes is a balanced approach to this  
18 concern when evaluating each proposal.

19 **II. SUMMARY OF RECOMMENDATIONS**

20 DRA offers the following summary of its recommendations on the power  
21 charge indifference adjustment (PCIA) and other DA Phase III issues, which will  
22 be discussed in further detail in section III:

23 **PCIA Issues:**

- 24 1. Adjust the market price benchmark (MPB) to reflect the market value of  
25 renewable portfolio standard (RPS) resources in the total portfolio for  
26 each vintage.
- 27 2. Use the current MPB methodology to determine the market value of non-  
28 RPS resources and a transparent renewable energy credit (REC) market  
29 value to determine the market value of RPS resources.
- 30 3. Use accurate and publicly available information to determine the market  
31 value for resource adequacy (RA) capacity.

- 1 4. Remove load related California Independent System Operator (CAISO)  
2 costs from total portfolio costs.
- 3 5. Adopt a uniform treatment of short-term energy market transactions with  
4 contract term less than one year for all investor-owned utilities (IOUs).
- 5 6. Use publicly available information to determine on-peak and off-peak  
6 weights for the MPB.
- 7 7. Eliminate continuous DA status when a continuous DA customer returns  
8 to bundled service.
- 9 8. **ESP Financial Security Requirements:** Assure that the bonding  
10 requirement is sufficient to cover the re-entry fee of involuntarily returned  
11 customers and avoid cost shifting to bundled customers.
- 12 9. **Switching Rules:** Maintain current DA switching rules.
- 13 10. **TBS Rate:** Make the TBS rate consistent with the proposed changes to  
14 the PCIA by including RA and RPS charges and reflecting modifications  
15 to the PCIA methodology.

### 16 III. DISCUSSION

#### 17 PART 1: POWER CHARGE INDIFFERENCE ADJUSTMENT

##### 18 A. Adjust the Market Price Benchmark to Capture the 19 Value of Renewable Portfolio Standard Eligible 20 Resources

21 The parties generally agree that the MPB needs to be adjusted or updated to  
22 reflect the increased costs of procuring renewable resources and some other new  
23 costs that were not considered at the time the current MPB methodology was  
24 adopted. However, parties disagree as to what is the best methodology to do this.  
25 The only proposal discussed at length at the workshops is the proposal by the Joint  
26 Parties<sup>1</sup> to update the calculation of the MPB to reflect the cost of renewables  
27 using a weighted average of the RPS and non-RPS eligible resources in the total  
28 portfolio. Under this methodology, the percentage of RPS resources is multiplied

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<sup>1</sup> Marin Energy Authority, Direct Access Customer Coalition, Alliance for Retail Energy Market, City and County of San Francisco, California State University, California Municipal Utilities Association, Commercial Energy, Pilot Power Group, Inc., Energy Users Forum, BlueStar Energy, San Joaquin Valley Power Authority, School Project for Utility Rate Reduction and the Retail Energy Supply Association.

1 by the market value of RPS resources, the percentage of non-RPS resources is  
2 multiplied by the market value of non-RPS resources, and the two products are  
3 added together to derive the weighted average MPB. DRA believes this proposal  
4 is reasonable and supports it.

5 The composition of RPS and non-RPS resources in the total portfolio may  
6 vary by the vintage, which is determined by the actual date of departure from  
7 bundled service, so the actual percentage of RPS and non-RPS resources must be  
8 used to calculate the MPB for each PCIA vintage. The RPS and non-RPS  
9 composition should be based on publicly available information in the IOUs'  
10 Energy Resource Recovery Account (ERRA) applications.

11 The weighted average proposal also requires an accurate market value for  
12 the RPS and non-RPS resources; however, there is no current market data  
13 available for RPS resources. To address this issue, DRA supports using the  
14 current MPB methodology to determine the market value of non-RPS resources.  
15 DRA also supports using a transparent renewable energy credit (REC) market  
16 value to determine the market value of RPS resources when it becomes available.

### 17 **1. Value of Non-RPS Eligible Resources**

18 Most parties at the workshops appear to agree on how to determine the  
19 market value of non-RPS resources. DRA supports determining the market value  
20 of non-RPS resources using the current MPB methodology based on an average of  
21 one-year strip of power futures quotes for NP15 and SP15 for the coming calendar  
22 year from Megawatt Daily published from October 1<sup>st</sup> through October 31<sup>st</sup> of the  
23 prior year. The current MPB methodology uses a weighted average of on-peak  
24 and off-peak futures quotes based on sixteen on-peak hours each day from  
25 Monday through Saturday (6X16). There is no debate over the transparency of  
26 the futures-based MPB, since it relies upon published data that can be verified by  
27 interested parties. However, Commission action may be necessary to ensure the  
28 continued accuracy of the futures based MPB in the event changes are called for to  
29 address the impact of cap-and-trade regulations, as discussed below.

1           Since the MPB is based on one-year strip of power futures quotes, it may  
2 be affected by the California cap-and-trade regulations scheduled to take effect on  
3 January 1, 2012. The IOUs indicated, at the January 6, 2011 Demand Response  
4 (DR) workshop, that the cost of carbon is now embedded in the NP15 and SP15  
5 futures quotes as a result of the cap-and-trade regulations. There is insufficient  
6 information at this point to determine what impact, if any, the cap-and-trade  
7 regulations will have on the futures quotes. However, DRA urges the  
8 Commission to monitor this situation closely and take corrective action, if  
9 necessary, to ensure the accuracy of the futures-based MPB and prevent cost  
10 shifting.

## 11                           **2. Value of RPS Eligible Resources**

12           Many of the proposals introduced at the workshops included an option to  
13 determine the market value of RPS resources using transparent REC market values  
14 once the REC market is established. Under this approach, the market value of  
15 RPS resources is determined by adding the market value of the energy and the  
16 market value of the REC. DRA supports the concept of using publicly available  
17 information to determine the market value of RPS resources.

18           Since there is no easy or perfect way to estimate the value of RPS resources  
19 until the REC market is established and actual market data can be used, parties  
20 have discussed using a temporary proxy price that all parties can support. At the  
21 December 14, 2010, December 15, 2010 and January 4, 2011 workshop  
22 discussions, the parties acknowledged that it may not be possible to come up with  
23 a completely accurate temporary proxy price using publicly available information;  
24 at the same time, parties could not reach an agreement on the use of confidential  
25 information. Thus, no consensus was reached on this issue. In the end, DRA  
26 prefers to use the best and most accurate and publicly available information.  
27 However, DRA is open to reviewing reasonable proposals and will address these  
28 proposals in reply testimony.

1           **B.     Replace Fixed Resource Adequacy/Capacity**  
2           **Adders with Capacity Costs**

3           The Joint Utilities indicated that the existing resource adequacy  
4 (RA)/capacity adders were adopted as part of an overall settlement agreement on  
5 the current PCIA methodology adopted in Commission Decision D.06-07-030,<sup>2</sup>  
6 and subsequently modified in Commission Decision D.07-01-030,<sup>3</sup> and may no  
7 longer reflect the value of RA capacity costs today. The Joint Utilities propose to  
8 create a market value for RA capacity by multiplying the price set by the CAISO’s  
9 interim capacity procurement mechanism (ICPM) – to be replaced by the  
10 (pending) capacity procurement mechanism (CPM)<sup>4</sup> – by the net qualifying  
11 capacity (NQC) for the portfolio on a vintage basis. The CPM is the CAISO  
12 “backstop” mechanism that authorizes it to procure resources when there is a  
13 deficiency in the RA procurement, and additional capacity is needed to maintain  
14 the reliability of the grid.

15           DRA supports the idea of using a market value for RA capacity based on an  
16 accurate and publicly available source. The CPM is a fixed, FERC-approved  
17 price paid by the CAISO, so it is publicly available information. However, DRA  
18 has concerns over the accuracy of the CPM as a proxy for the market value of RA  
19 capacity given the California Public Utilities Commission (CPUC) Energy  
20 Division’s conclusion that sufficient RA capacity was available throughout the  
21 2009-10 RA compliance cycles to load serving entities (LSEs) at or below the  
22 \$40/kW-year “waiver trigger” price. (An LSE that cannot procure resources  
23 under the \$40/kW-year “waiver trigger” price is exempt from Commission  
24 penalties for failing to procure their RA requirements, but would be responsible  
25 for the CAISO’s backstop procurement costs (currently set at \$41/kW-year ICPM

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<sup>2</sup> D.06-07-030, pp 10-13.

<sup>3</sup> D.07-01-030, pp 3-5.

<sup>4</sup> The CAISO’s Tariff Amendment Filing to implement the Capacity Procurement Mechanism (filed December 1, 2010) is pending Federal Energy Regulatory Commission approval in docket (ER11-2256-000).

1 price.) Thus, the waiver-trigger price and CAISO ICPM backstop price, taken  
2 together, establish the maximum price an LSE would want to pay for RA  
3 procurement. While this is a clear and publicly available price, DRA is not  
4 certain that the maximum backstop price should be used for the RA capacity  
5 value, particularly in light of the fact that RA prices have been trading at well  
6 under this \$41/kW year price. In addition, it is not yet clear that FERC will  
7 approve the increased CPM price of \$55/kW-year requested in the CAISO's CPM  
8 Tariff Amendment filing.

9 **C. Remove Load Related CAISO Costs From Total**  
10 **Portfolio Costs**

11 The Joint Parties maintain that as load departs, certain charges for ancillary  
12 services, grid management charges, and a variety of other load-related CAISO  
13 charges that would otherwise be paid by the utilities to the CAISO will be  
14 reduced. However, these cost savings are not currently reflected in the MPB.  
15 Thus, either the MPB must be adjusted to reflect the cost savings, or the costs in  
16 the total portfolio should be removed. DRA supports the Joint Utilities' proposal  
17 to remove all load-related CAISO costs from total portfolio costs to resolve this  
18 problem. It is reasonable and more efficient to exclude the load-related CAISO  
19 cost components from total portfolio costs than to continue to include them and try  
20 to determine a proper adjustment to the MPB.

21 Since the Joint Utilities proposal would exclude only load-related CAISO  
22 cost components, the Commission must establish clear guidelines for identifying  
23 and distinguishing between load and generation related CAISO cost components.  
24 This will allow parties to verify that only load-related cost components were  
25 removed from total portfolio costs.

26 **D. Short Term Energy Market Transactions**

27 The Joint Utilities indicated that short-term energy market transactions with  
28 contract terms less than one year are made on behalf of all bundled customers but  
29 are not included in the total portfolio costs of all the IOUs. These short-term  
30 transactions are included in the total portfolio costs of Southern California Edison



1 Company (SCE), but not for Pacific Gas and Electric Company (PG&E) and San  
2 Diego Gas and Electric Company (SDG&E). SCE has agreed to exclude such  
3 short term transactions from total portfolio costs as well to be consistent with  
4 treatment by PG&E and SDG&E. DRA supports a uniform treatment of short-  
5 term energy market transactions with contract terms less than one year by the  
6 IOUs. It may also be reasonable to have a uniform treatment of all customers  
7 departing bundled service in the same year.

8 Under the vintaging methodology adopted in Decision D.08-09-012,<sup>5</sup> a  
9 customer departing in the first half of the year is assigned a departure date of  
10 December 31<sup>st</sup> of the prior year, while a customer departing in the second half of  
11 the year is assigned a departure date of December 31<sup>st</sup> of the current year.  
12 Customers departing in the first half may not be held responsible for some of the  
13 resource commitments made after their actual departure, while customers  
14 departing in the second half may be responsible for resource commitments made  
15 after their actual departure. The potential benefits and adverse effects to bundled  
16 customers are expected to balance out over the long run.

17 It may be reasonable to treat all customers departing in the same year  
18 similarly by excluding short-term energy market transactions from total portfolio  
19 costs. The impact on bundled customers is expected to be minimal due to the  
20 balancing of potential benefits and adverse effects over time. DRA recommends  
21 the Commission also order the IOUs to record actual expenses related to short-  
22 term transactions and be prepared to report on these expenses as directed by the  
23 Commission or in response to parties' data requests.

24 **E. Load Profile Weighing of the Market Price**  
25 **Benchmark**

26 The Joint Parties argued that the MPB does not reflect the value of the  
27 delivery profile of the so called "brown" or non-RPS resources, even though the  
28 delivery profile of the resources is reflected in the IOU costs used to calculate the

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<sup>5</sup> D.08-09-012, pp 64-68.

1 PCIA charges. Two options have been proposed at the workshops to address this  
2 concern. First, the Joint Parties proposed to replace the existing 6X16 load  
3 profile with the IOU bundled load profiles to determine the on-peak and off-peak  
4 weights for the MPB. However, the Joint Parties do not want to share their  
5 individual, confidential bundled load profiles with other parties. Second, the  
6 Joint Utilities suggested using the IOU generation profiles instead of the bundled  
7 load profiles. However, this does not avoid the problem of relying on  
8 confidential data. DRA opposes the use of confidential IOU load profile  
9 information that may not be a good proxy for the departing load profile. In  
10 addition, the proposal to use confidential information increases the complexities  
11 without demonstrating any increase in the accuracy of the MPB methodology.

12 The Commission acknowledged, in Decision D.04-12-048,<sup>6</sup> that there is a  
13 potential mismatch between the types of resources that the utility needs to procure  
14 for its bundled customers and the types of resources that departing customers  
15 require. It may not be possible for the utility to develop a resource portfolio that  
16 accurately matches the load profile of the expected departing load, and the IOU's  
17 generation profile may not be a good proxy of it. It may also be true that the  
18 transparent 6X16 load profile currently in use may not be a good proxy of the  
19 departing load profile either.

20 There is insufficient justification at this point for replacing an imperfect but  
21 transparent proxy load profile with one that is imperfect and non-transparent.  
22 Using confidential load profile information will only increase the number of  
23 MPB calculations required. The 6X16 load profile only requires one MPB  
24 calculation for all vintages since it uses the same on-peak and off-peak weights.  
25 However, the on-peak and off-peak weights for the IOU load profiles vary by  
26 vintage, and thus require a separate MPB calculation for each PCIA vintage. The  
27 proposal to use confidential information increases the complexities without any  
28 demonstrated increase in accuracy, and thus, should be rejected.

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<sup>6</sup> D.04-12-048, pp 55-63.

1           **F.      Continuous Direct Access Customers**

2           The Commission, in Decision D.02-11-022,<sup>7</sup> excluded continuous DA  
3 customers that remained on DA both before and after February 1, 2001 from both  
4 the Department of Water Resources (DWR) bond charge and DWR power charge  
5 since the DWR did not purchase power to serve customers that took DA service  
6 continuously both before and after DWR began purchasing power in January  
7 2001. The Commission, in Decision D.06-07-030,<sup>8</sup> adopted the PCIA to recover  
8 costs associated with new generation resources, but continued to exclude  
9 customers with continuous DA status, since they were exempt from both the DWR  
10 bond charge and the DWR power charge. This enabled these customers to return  
11 to bundled service and receive the benefit of lower-cost pre-restructuring resources  
12 while avoiding some of their fair share of costs of new, more expensive resources,  
13 thus shifting costs to bundled customers when they depart bundled service to  
14 return to DA service.

15           DRA supports the Joint Utilities' proposal to close the current "loophole"  
16 allowing customers to maintain their continuous DA status and avoid paying their  
17 fair share of costs when switching between bundled and DA services. These  
18 customers should not have the indiscriminate ability to come and go from bundled  
19 service without regard to the cost-shifting effects on the remaining bundled  
20 customers. Continuous DA status must be terminated upon return to bundled  
21 service, and a new vintage assigned under the vintaging methodology upon  
22 departure from bundled service to ensure customers are held responsible for costs  
23 incurred on their behalf and prevent cost shifting.

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<sup>7</sup> D.02-11-022, pp 4-5, 60-64.

<sup>8</sup> D.06-07-030, pp 25-28.

1 **PART 2: ESP FINANCIAL SECURITY REQUIREMENT**

2 DRA recommends that at a minimum, the bonding requirement should be  
3 sufficient to cover the re-entry fees imposed on involuntary return customers to  
4 prevent cost shifting to bundled customers. The re-entry fees should include the  
5 administrative fee imposed by the utility for implementing the customer’s change  
6 of service request and the obligation to pay the TBS rate for a period of six months  
7 after notice is first given to the utility that the customer is returning.

8 Since the TBS rate is tied to spot market prices, it could result in the  
9 returning customer paying a higher rate than other IOU customers for the six  
10 month transition period, resulting in a re-entry “fee.” The TBS rate covers the  
11 IOU’s costs of incremental procurement resulting from the involuntarily returned  
12 customers, and thus protects bundled customers against cost shifting. If the spot  
13 market price is lower than the bundled customer rate, the returning customers  
14 would not have to pay any TBS fee. The TBS rate must also include the costs  
15 associated with RA requirements, RPS compliance, and modifications to the PCIA  
16 methodology.

17 The Commission must also consider market risk when determining the  
18 appropriate bonding requirements. An entity that relies heavily on the spot  
19 market for a significant portion of its supplies has more exposure to the highly  
20 volatile spot market prices than an entity that rely heavily on long term energy  
21 contracts and/or generation ownership for a significant portion of its supplies.  
22 The bonding requirement for these entities should reflect the amount of exposure  
23 to the highly volatile energy markets.

24 DRA prefers a reasonable bond calculation methodology that will capture  
25 all the appropriate costs without placing an undue burden on ESPs while maintain  
26 bundled customer indifference. DRA is open to reviewing reasonable proposals  
27 and will address these proposals in reply testimony.

1 **PART 3: DIRECT ACCESS SWITCHING RULES**

2 DRA believes the current switching restrictions applicable to voluntary and  
3 involuntary return customers are appropriate and do not need to be modified at this  
4 time. DA customers have the flexibility to voluntarily switch between DA  
5 service and bundled service by providing a six month advance notice. During the  
6 six month waiting period, a voluntarily returned customer may remain with the  
7 ESP or return to bundled service under the applicable TBS rate. A voluntarily  
8 returned customer going to bundled service without a six month advance notice  
9 will be placed under the applicable TBS rate for six months. After six months,  
10 returning customers are subject to the same pricing terms and conditions as apply  
11 to other bundled customers.

12 Commission Decision D.03-05-034<sup>2</sup> determined that, when a DA customer  
13 is involuntarily returned to bundled service as a result of the ESP unilaterally  
14 discontinuing DA service, the DA customer may enter the 60-day “safe harbor”  
15 without having an immediate candidate for a new ESP. The temporary safe  
16 harbor allows the customer to continue receiving service while switching from one  
17 ESP to another but is required to pay the applicable TBS rate. If a Direct Access  
18 Service Request (DASR) is not submitted by the end of the 60 days, the customer  
19 will be returned to bundled service and becomes subject to the same pricing terms  
20 and conditions as apply to other bundled customers. The bonding requirement  
21 will ensure that any costs associated with involuntary returns are not shifted to  
22 bundled customers. Since the bonding requirements are intricately interwoven  
23 with the switching rules, modifications to the bond calculation methodology may  
24 warrant revising the switching rules. DRA is open to reviewing reasonable  
25 proposals and will address these proposals in reply testimony.

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<sup>2</sup> D.03-05-034 pp 18-23.

1 **PART 4: TRANSITIONAL BUNDLED SERVICE RATE**

2 DRA supports the Joint Utilities’ proposal to update the TBS rate to reflect  
3 any modifications to the PCIA methodology. The TBS is the rate that returning  
4 customers pay for a period of six months, when they leave an ESP or community  
5 choice aggregation (CCA) without a six month advance notice. DA customers on  
6 the transitional 60-day “safe harbor” period while switching from one ESP to  
7 another also pay the TBS rate. The TBS rate is based on the prevailing spot  
8 market price plus all applicable generation-related surcharges that apply to DA  
9 customers and therefore is designed to help protect bundled customers from cost  
10 shifting and keep them indifferent.

11 The TBS rate needs to be made consistent with the updates to the PCIA by  
12 including RA and RPS charges. The IOU’s total load and RA requirements  
13 increase as customers return to bundled service, so the appropriate RA charges  
14 must also be reflected in the TBS rate to ensure returning customers pay their fair  
15 share of RA charges and avoid cost shifting. RPS charges are currently not  
16 included in TBS rates and must be reflected to ensure customers returning to  
17 bundled service pay their fair share of RPS charges and avoid cost shifting.

18 Only the Joint Utilities’ proposal to adjust the TBS rates to reflect RA and  
19 RPS charges using energy and capacity scalars was discussed at length at the  
20 workshops.<sup>10</sup> The energy scalar is the ratio of the weighted average MPB to the  
21 market value of non-RPS resources. The capacity scalar is ratio of the market  
22 value of non-RPS resources plus the market value of capacity to the market value  
23 of non-RPS resources. The TBS rates will be multiplied by both the energy and  
24 capacity scalars to reflect RA and RPS charges. DRA finds this proposal  
25 reasonable and supports it.

26  

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<sup>10</sup> See Attachment A to Joint Comments of Pacific Gas and Electric Company, San Diego Gas & electric Company and Southern California Edison Company, January 21, 2010.

1 **Appendix A**

2 **Qualifications and Prepared Testimony of Ke Hao Ouyang**

3 Q.1. Please state your name and business address.

4 A.1. My name is Ke Hao Ouyang. My business address is 505 Van Ness Avenue,  
5 San Francisco, CA 94102.

6 Q.2. By who are you employed and what is your job title?

7 A.2. I am employed by the California Public Utilities Commission as a  
8 Regulatory Analyst III in the Electric Pricing and Consumer Program  
9 Branch of the Division of Ratepayer Advocates (“DRA”).

10 Q.3. Please describe your educational background and professional experience.

11 A.3. I received a Bachelor of Art Degree in Applied Mathematics and  
12 Economics from the University of California, Berkeley in 2005.

13 I joined the Electric Pricing and Consumer Program Branch of the Division  
14 of Ratepayer Advocates in June 2010, and have been assigned to work on  
15 Community Choice Aggregation and Direct Access related issues.

16 Q.4. What is your area of responsibility in this proceeding?

17 A.4. I am sponsoring DRA’s prepared testimony in the Direct Access  
18 proceeding.

19 Q.5. Does this conclude your opening testimony?

20 A.5. Yes.

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day served a copy of the document  
“**TESTIMONY ON THE METHODOLOGY FOR CALCULATING  
DEPARTING LOAD NON-BYPASSABLE CHARGES, DIRECT ACCESS  
SWITCHING RULES, ELECTRIC SERVICE PROVIDER FINANCIAL  
SECURITY REQUIREMENT AND TRANSITIONAL BUNDLED  
SERVICE RATE**” to the official service list in **R.07-05-025** by using the  
following service:.

**BY E-MAIL:** I sent a true copy via e-mail to all known parties of  
record who have provided e-mail addresses.

**BY MAIL:** I sent a true copy via first-class mail to all known parties of  
record.

Executed on **January 31, 2011** at San Francisco, California.

/s/ REBECCA ROJO

---

Rebecca Rojo



**SERVICE LIST**  
**R.07-05-025**

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