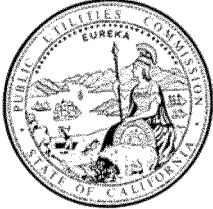


Docket: : R.07-05-025  
Exhibit Number :  
Commissioner : Michael Peevey  
Admin. Law Judge : Thomas Pulsifer  
DRA Witness : Ke Hao Ouyang



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

**REPLY 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**

San Francisco, California  
February 25, 2011

## TABLE OF CONTENTS

<b>I.</b>	<b>INTRODUCTION.....</b>	<b>1</b>
<b>II.</b>	<b>DRA RECOMMENDATIONS.....</b>	<b>2</b>
<b>III.</b>	<b>DISCUSSION.....</b>	<b>3</b>
<b>PART 1:</b>	<b>CONSENSUS ISSUES .....</b>	<b>3</b>
	<b>1. Load-Related CAISO Costs.....</b>	<b>3</b>
	<b>2. Short-Term Energy Market Transactions .....</b>	<b>3</b>
	<b>3. Six Months’ Advance Notice .....</b>	<b>4</b>
	<b>4. Transitional Bundled Service Rate.....</b>	<b>4</b>
<b>PART 2:</b>	<b>UNRESOLVED ISSUES .....</b>	<b>5</b>
	<b>A. VALUE OF RPS-ELIGIBLE RESOURCES.....</b>	<b>5</b>
	<b>1. PG&amp;E Proposal .....</b>	<b>7</b>
	<b>2. SCE and SDG&amp;E Proposal .....</b>	<b>8</b>
	<b>3. Joint Parties Proposal .....</b>	<b>9</b>
	<b>4. CLECA-CMTA Joint Proposal.....</b>	<b>11</b>
	<b>5. L. Jan Reid Proposal .....</b>	<b>12</b>
	<b>B. RESOURCE ADEQUACY CAPACITY VALUE.....</b>	<b>12</b>
	<b>C. LOAD PROFILE WEIGHING OF THE MARKET PRICE BENCHMARK.....</b>	<b>13</b>
	<b>D. ESP FINANCIAL SECURITY REQUIREMENT.....</b>	<b>14</b>
	<b>APPENDIX A – QUALIFICATION OF WITNESS</b>	
	<b>CERTIFICATE OF SERVICE</b>	

(Witness: Ke Hao Ouyang)

**I. INTRODUCTION**

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

DRA received and reviewed opening testimony from the California Large Energy Consumers Association (CLECA), California Manufacturers and Technology Association (CMTA),<sup>1</sup> Joint Parties,<sup>2</sup> L. Jan Reid,<sup>3</sup> Pacific Gas and Electric Company (PG&E),<sup>4</sup> Southern California Edison Company (SCE)<sup>5</sup> and San Diego Gas and Electric Company (SDG&E).<sup>6</sup> The parties expressed a common goal to use publicly available, transparent data whenever possible and to ensure that bundled customers are indifferent (i.e., no better or worse off) as a result of departing load. The apparent common understanding

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<sup>1</sup> Testimony of Dr. Barbara R. Barkovich on behalf of the California Large Energy Consumers Association and the California Manufacturers and Technology Association (CLECA-CMTA Testimony), January 31, 2011.

<sup>2</sup> Testimony of John P. Dalessi, Mark E. Fulmer, Margaret A. Meal on behalf of the Joint Parties on a Fair and Reasonable Methodology to Determine the Power Charge Indifference Adjustment and the Competition Transition Charge and Testimony of Mark E. Fulmer on behalf of the Direct Access Parties concerning the Transitional Bundled Service Rate, Direct Access Switching Rules, Minimum Stay Provisions, and Energy Service Provider Financial Security Requirements (Joint Parties’ Testimony – Parts 1-2), January 31, 2011.

<sup>3</sup> Direct Testimony of L. Jan Reid on Phase III Direct Access Issues (L. Jan Reid Testimony), January 31, 2011.

<sup>4</sup> Pacific Gas and Electric Company Direct Access Reopening Phase III Prepared Testimony (PG&E Testimony), January 31, 2011.

<sup>5</sup> Direct Access Rulemaking Phase III Testimony of Southern California Edison Company (SCE Testimony), January 31, 2011.

<sup>6</sup> Prepared Direct Testimony of James Spurgeon, Cynthia S. Fang and Toni Choi for San Diego Gas & Electric Company (SDG&E Testimony – Chapters 1-3), January 31, 2011.

1 from the December 2010 and January 2011 workshops is confirmed by a uniform  
2 recommendation on several key issues. However, the parties remain divided on several  
3 other key issues in the absence of publicly available, transparent data.

4 Some parties proposed using confidential investor-owned utilities' (IOU)  
5 information, subject to review and verification by the California Public Utilities  
6 Commission's (CPUC) Energy Division or a third party non-market participant to resolve  
7 the remaining key issues. However, these same parties do not want to share their  
8 individual, confidential information with other parties. Some parties also suggested, for  
9 administrative ease, to use a single estimation for all power charge indifference  
10 adjustment (PCIA) vintages despite acknowledging such action may risk the integrity of  
11 the data. DRA addresses all of these issues in detail in the sections below.

## 12 **II. DRA RECOMMENDATIONS**

13 DRA recommends the Commission adopt the parties' uniform recommendation on  
14 the following proposals on several key PCIA, switching rule, and TBS rate issues:

### 15 **PCIA Issues:**

- 16 1. Remove all load-related California Independent System Operator (CAISO) costs  
17 from total portfolio costs.
- 18 2. Adopt a uniform treatment for short-term energy market transactions with  
19 contract terms of less than one year for all IOUs by excluding such transactions  
20 from total portfolio costs.
- 21 3. **Switching Rules:** Maintain current rule requiring customers to provide six  
22 months' advance notice before switching between bundled and DA services.
- 23 4. **TBS Rate:** Make the TBS rate consistent with the proposed changes to the  
24 PCIA by including resource adequacy (RA) and renewable portfolio standard  
25 (RPS) charges and reflecting modifications to the PCIA methodology.

26 Due to the lack of a renewable energy market with publicly available, transparent  
27 market data, the parties could not agree on the appropriate methodology for determining  
28 the market value of RPS-eligible resources. Furthermore, until the legal issues pertaining  
29 to ESP financial security requirements are resolved, it seems highly unlikely that parties  
30 would be able to agree to a particular bonding methodology. Based on its review of

1 testimony and participation in workshop discussions, the following are DRA’s  
2 recommendations for resolution of the unresolved issues:

3 **PCIA Issues:**

- 4 1. Use a publicly available, transparent renewable energy credit (REC) market  
5 value to determine the market value of RPS resources.
- 6 2. Use accurate and publicly available information to determine the market value  
7 for RA capacity.
- 8 3. Use publicly available information to determine on-peak and off-peak weights  
9 for the market price benchmark (MPB).
- 10 4. **ESP Financial Security:** Adopt a bonding methodology that prevents cost  
11 shifting to bundled customers when DA customers are involuntarily returned to  
12 bundled service.

13 **III. DISCUSSION**

14 **PART 1: CONSENSUS ISSUES**

15 Some parties were unwilling to commit to any agreement in principle despite an  
16 apparent common understanding on several key issues after constructive discussions  
17 during the December 2010 and January 2011 workshops. However, this common  
18 understanding is confirmed by a uniform recommendation in their opening testimony on  
19 several key issues pertaining to load-related CAISO costs, short-term energy market  
20 transactions, six months’ advance notice requirement, and TBS rates. DRA recommends  
21 the Commission adopt the parties’ uniform recommendations on the following  
22 “consensus” issues:

23 **1. Load-Related CAISO Costs**

24 The IOUs should remove all load-related CAISO costs from total portfolio costs.  
25 This will eliminate the need to calculate the reduction in load-related CAISO costs as  
26 load departs.

27 **2. Short-Term Energy Market Transactions**

28 The IOUs should adopt a uniform treatment of short-term energy market  
29 transactions with contract terms less than one year by excluding such transactions from

1 total portfolio costs. This will ensure the IOUs use a consistent and uniform PCIA  
2 methodology.

### 3 **3. Six Months' Advance Notice**

4 Customers switching voluntarily between DA service and bundled service must  
5 continue to provide a six months' advance notice. During the six month waiting period, a  
6 voluntarily returned DA customer may remain with the ESP or return to bundled service  
7 under the applicable TBS rate. A voluntarily returned DA customer going to bundled  
8 service without providing six months' advance notice will be placed under the applicable  
9 TBS rate for six months. After six months, returning customers are subject to the same  
10 pricing terms and conditions as apply to other bundled customers. Requiring six months'  
11 advance notice is also consistent with Commission Decision (D.) 03-05-034, and  
12 provides a reasonable opportunity for the utility to adjust its portfolio, process Notices of  
13 Intent (NOI) supplied by the customer, adjust RA compliance filings, and process DA  
14 Service Requests (DASR).<sup>7</sup>

### 15 **4. Transitional Bundled Service Rate**

16 The TBS rate should be made consistent with the updates to the PCIA by  
17 including RA and RPS charges and reflecting any modifications to the PCIA  
18 methodology. RA and RPS charges are currently not included in the TBS rates.  
19 Therefore, they must be reflected in the TBS rates to ensure DA customers returning to  
20 bundled service pay their fair share of RA and RPS charges. Under the current PCIA  
21 methodology, an RA adder is included in the MPB to account for RA charges. The  
22 proposed modification to the PCIA methodology will include the equivalence of a RPS  
23 adder in the MPB to account for RPS charges. DRA recommends that the same RA and  
24 RPS adders be added to the TBS rates to reflect RA and RPS charges.

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<sup>7</sup>D.03-05-034, pp. 39-43, 48, 52.

1 **PART 2: UNRESOLVED ISSUES**

2 **A. Value of RPS-Eligible Resources**

3 CLECA-CMTA,<sup>8</sup> DRA,<sup>9</sup> the Joint Parties,<sup>10</sup> PG&E,<sup>11</sup> SCE<sup>12</sup> and SDG&E<sup>13</sup>  
4 generally agree to update the calculation of the MPB to reflect the cost of renewable  
5 resources by multiplying the percentage of RPS resources by the market value of RPS  
6 resources, and the percentage of non-RPS resources by the market value of non-RPS  
7 resources. However, there is no agreement on the appropriate methodology for  
8 determining the market value of RPS resources. The parties are also supportive of using  
9 a transparent REC market value to determine the market value of RPS resources.  
10 However, such information is not yet available, and the Joint Parties expressed concerns  
11 on the accuracy of preliminary REC market data, due to Commission-imposed  
12 restrictions on the use of tradable renewable energy credits (TRECs) and on TREC  
13 prices.

14 The Joint Parties believe that an open, transparent, and liquid market for  
15 renewable power that will provide transparent market price information for RPS  
16 resources will exist in the future. However, they are skeptical that initial market pricing  
17 information from the newly established market for TRECs that may arise out of D.11-01-  
18 025 would be appropriate due to the restrictions on the use of TRECs.<sup>14</sup> The Joint Parties  
19 did not provide any information on how the Commission imposed restrictions will affect  
20 the market value for TRECs.

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<sup>8</sup> CLECA-CMTA Testimony, pp. 11-12.

<sup>9</sup> Division of Ratepayer Advocate 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 (DRA Testimony), January 31, 2011, pp. 2-3.

<sup>10</sup> Joint Parties' Testimony – Part 1, p. 4.

<sup>11</sup> PG&E Testimony – Chapter 1, p. 13.

<sup>12</sup> SCE Testimony, p. 25.

<sup>13</sup> SDG&E Testimony – Chapter 2, p. 5.

<sup>14</sup> Joint Parties' Testimony – Part 1, pp. 22-23.

1           The Commission, in D.10-03-021, permitted the IOUs to fulfill up to 25% of their  
2 annual RPS procurement obligations using TRECs.<sup>15</sup> The Commission also imposed a  
3 transitional price cap of \$50/REC in REC-only contracts used for RPS compliance until  
4 December 31, 2011 to protect ratepayers from excessive payments for TRECs in the early  
5 stages of the TREC market.<sup>16</sup> The \$50/REC price cap was extended until December 31,  
6 2013 in D.11-01-025.<sup>17</sup> In addition, the 25% limit on REC usage was extended to all  
7 ESPs in D.11-01-026.<sup>18</sup>

8           The Commission-imposed restrictions on the use of TRECs are intended to protect  
9 ratepayers from excessive payments for TRECs in the early stages of the TREC market  
10 and to promote the development of new RPS-eligible generation. However, the  
11 Commission also noted that in the early years of a California TREC market, prior to load  
12 serving entities' (LSE) attaining the goal of 20% of retail sales from RPS-eligible  
13 generation resources, demand for TRECs is likely to exceed supply.<sup>19</sup> Therefore, in  
14 DRA's view, the Commission-imposed restrictions should have little to no impact on  
15 TREC prices given the expected supply shortage.

16           DRA reiterates its preference to use the best and most accurate and publicly  
17 available information, but acknowledges that the most accurate and up-to-date  
18 information is not always available due to confidentiality concerns. Some parties  
19 proposed using confidential IOU RPS resource contract information subject to review  
20 and verification by the CPUC's Energy Division or a third party non-market participant,  
21 but these parties have concerns over sharing their individual, confidential RPS resource  
22 contract information with other parties and are reluctant to do so.

23           If the Commission were to consider using confidential information to determine an  
24 interim proxy price for RPS resources, DRA recommends the Commission include

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<sup>15</sup> D.10-03-021, pp. 40-49, 89, 93.

<sup>16</sup> D.10-03-021, pp. 54-61, 89-90, 101-102.

<sup>17</sup> D.11-01-025, pp. 20-24, 35-36, 44.

<sup>18</sup> D.11-01-026, pp. 16-18, 27-29.

<sup>19</sup> D.10-03-021, Finding of Fact (FOF) 9, p. 89.



1 confidential information from all LSEs, since non-IOUs represent a considerable portion  
 2 of total load. The information could be submitted to the Energy Division and then shared  
 3 on a blind and aggregated basis. As shown in Table 1 below, despite representing only  
 4 0.3% of total utility distribution company (UDC) customers, DA customers accounted for  
 5 approximately 10.1% of total UDC load as of December 31, 2010. The Joint Parties also  
 6 projected that in 2011, non-IOUs will represent 12% of the load subject to the 20% RPS  
 7 requirement.<sup>20</sup>

8 DRA supports using publicly available, transparent REC market values to  
 9 determine the market price of RPS resources when this information becomes available.  
 10 In the event that this information is not available, DRA supports developing an interim  
 11 proxy price that is either agreed upon by all parties or decided by the Commission based  
 12 on parties' input. There is no perfect solution to this problem, so the Commission may  
 13 have to determine which proposal is the most appropriate and reasonable. Below is  
 14 DRA's analysis of the proposals for determining the market value of RPS resources.

15 **Table 1**

16 **Direct Access Load and Customers as of December 31, 2010**

<b>Activities</b>	<b>Total</b>
1) Total Direct Access Customers	32,814
2) Total UDC Customers	11,516,053
3) Percent Direct Access Customers	0.3%
4) Total Direct Access Load (MWh)	18,806,798
5) Total UDC Load (MWh)	186,164,992
6) Percent Direct Access Load (MWh)	10.1%

17 Source: California Public Utilities Commission  
 18 <http://www.cpuc.ca.gov/PUC/energy/Retail+Electric+Markets+and+Finance/Electric+Markets/Direct+Access/>,  
 19 accessed on February 22, 2011.

20 **1. PG&E Proposal**

21 PG&E proposes to determine the market value of RPS resources using a  
 22 transparent, published REC index that represents the value of renewable generation in

<sup>20</sup> Joint Parties' Testimony – Part 1, p. 25.

1 California.<sup>21</sup> PG&E anticipates that a transparent REC market will be available by the  
2 third quarter of 2011. PG&E also anticipates that transparent REC indices will be  
3 included with the development of a REC market. If a transparent, published REC index  
4 has not been developed by the time a decision is issued on the Phase III issues, PG&E  
5 suggests that parties develop an interim proxy market value using the information from  
6 the IOU's energy resource recovery account (ERRA) forecast application. However,  
7 PG&E did not provide additional information on the process for developing an interim  
8 proxy price.

9 DRA finds the proposal to use a transparent, published REC index to determine  
10 the value for RPS resources reasonable. In the event that published REC indices are not  
11 readily available, it is reasonable to have the parties develop an agreed upon interim  
12 proxy price, though the task may be difficult, given the parties' disagreement. DRA  
13 believes the Commission may have to determine an interim proxy price based on parties'  
14 inputs.

## 15 **2. SCE and SDG&E Proposal**

16 SCE and SDG&E propose to determine the market value of RPS resources using  
17 the United States Department of Energy's (DOE) survey of reported contract premiums  
18 for renewable energy in the Western United States. DRA recommends conducting  
19 further studies before considering this proposal due to the concerns of the Joint Parties.  
20 The Joint Parties pointed out that green pricing program premiums may not reflect the  
21 cost of RPS resources, since the premiums are merely invested in green power sources as  
22 opposed to paying for an additional kilowatt-hour of green power.<sup>22</sup>

23 According to the DOE website, the survey data is based on utility green pricing  
24 programs, an optional utility service that allows customers an opportunity to support a  
25 greater level of utility company investment in renewable energy technologies.  
26 Participating customers pay a premium on their electric bills to cover the incremental cost

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<sup>21</sup> PG&E Testimony – Chapter 1, pp. 13-14.

<sup>22</sup> Joint Parties' Testimony – Part 1, pp. 26-27.

1 of additional renewable energy.<sup>23</sup> DRA concludes that there is insufficient information at  
2 this point to determine how much revenue is generated by the voluntary green pricing  
3 program premiums, and how much additional RPS resources are procured as a result.

### 4 **3. Joint Parties Proposal**

5 The Joint Parties propose to determine the market value of RPS resources using  
6 confidential IOU RPS resource contract prices for resources that began delivery in the  
7 current year and those projected to begin delivery in the following year, subject to  
8 verification by the CPUC Energy Division.<sup>24</sup> The proposal will only use average IOU  
9 RPS resource contract prices from the first two contract years, regardless of contract  
10 duration. In DRA's view, this proposal fails to capture the benefit of long-term contracts,  
11 overestimates the average cost of front-loaded generation facilities, and excludes contract  
12 costs of other LSEs. The Joint Parties' own analysis also revealed that Marin Energy  
13 Authority (MEA) was able to purchase RPS resources at a price below the IOU's 2010  
14 and 2011 RPS resource procurement costs. Therefore, DRA does not support this  
15 proposal.

16 Under the Commission's long-term procurement plan (LTPP) and RA programs,  
17 all LSEs have the obligation to acquire sufficient reserves for its customer loads, and  
18 most procure a range of short-, medium-, and long-term contracts. In particular, the  
19 IOU's RPS resources may come from long-term energy contracts and/or generation  
20 ownership. Long-term contracts can offer protection from the highly volatile energy  
21 markets, and are usually priced higher than spot market prices. Long-term contracts also  
22 provide a reliable supply of energy at a predetermined price for a fixed time period.  
23 Some of the benefits of long-term contracts are difficult to quantify. Yet, it is still  
24 important to take these unquantifiable attributes into consideration when comparing the  
25 costs of contracts of different durations.

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<sup>23</sup> <http://apps3.eere.energy.gov/greenpower/markets/pricing.shtml?page=0>, accessed on February 1, 2011.

<sup>24</sup> Joint Parties' Testimony – Part 1, pp. 24-26.

1           The IOUs also indicated that some RPS resources are generated from utility  
2 owned generation (UOG) facilities, which are often front loaded, meaning prices are  
3 higher in early years and lower in later years. The lower prices in the later years balance  
4 out the higher prices in the early years to make overall costs comparable to non-front  
5 loaded facilities. In order to compare apples to apples, the levelized costs of front-loaded  
6 facilities should be compared to the levelized costs of facilities that are not front-loaded  
7 to account for the price balancing effect over time.

8           In DRA's view, the Joint Parties' proposal to use only contract costs from the first  
9 two delivery years heavily discounts the benefit of long-term contracts by ignoring the  
10 fact that renewable energy would be delivered under the terms and conditions of the long-  
11 term contract. The Joint Parties' proposal also fails to capture the savings from later  
12 contract years, especially for front-loaded UOG resources. Failure to recognize these  
13 long-term benefits would result in an overestimation of the total cost of RPS eligible  
14 resources.

15           The Joint Parties' proposal relies on confidential RPS contract information, but the  
16 Joint Parties suggested that their RPS contract information, which includes community  
17 choice aggregations (CCAs) and ESPs, be withheld. The Joint Parties' rationale for  
18 relying only on confidential IOU data is that the IOUs are the counterparties to the vast  
19 majority of renewable transactions in the State, and this information is readily available  
20 in the IOU's ERRA forecast applications. However, as shown in Table 1 above, DA  
21 customers alone accounted for approximately 10.1% of total UDC load as of December  
22 31, 2010. In addition, the Joint Parties also projected that in 2011, non-IOUs are  
23 projected to represent 12% of the load subject to the 20% RPS requirements.<sup>25</sup> Failure to  
24 account for RPS contract information from LSEs representing such a considerable  
25 portion of total UDC load would reduce the accuracy of the estimated market value for  
26 RPS resources.

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<sup>25</sup> Joint Parties' Testimony – Part 1, p. 25.

1 Finally, the Joint Parties contradict their claim that the IOU's RPS resource  
2 contract price represents the market price for RPS resources with evidence that another  
3 LSE was able to purchase RPS resources at a price below the IOU's 2010 and 2011 RPS  
4 resource procurement costs.<sup>26</sup> The Joint Parties' testimony estimated that PG&E's  
5 average 2010 RPS procurement cost is approximately \$145/MWh, SCE's average 2011  
6 RPS and non-RPS procurement cost is approximately \$150/MWh, while MEA's RPS  
7 procurement cost is only approximately \$110/MWh. Marin Clean Energy's (MCE)  
8 website also provided a link to an article in the Marin Independent Journal, which  
9 reported that MEA will pay G2 Energy about \$100/MWh for 25,000MWh of renewable  
10 electricity per year from landfill gas facilities over at least 20 years, scheduled for  
11 delivery in mid- to late 2011.<sup>27</sup> If MEA is able to purchase RPS resources below the  
12 average IOU RPS resource contract price, then this clearly shows that the average IOU  
13 RPS resource contract price is not the market price for RPS resources.

#### 14 4. CLECA-CMTA Joint Proposal

15 CLECA-CMTA proposes to determine the market value of RPS resources using  
16 confidential IOU renewable resource contract prices that will be used to serve bundled  
17 customers in the upcoming ERRA year, subject to verification by the CPUC Energy  
18 Division and/or an independent third party non-market participant.<sup>28</sup> CLECA-CMTA  
19 acknowledges that renewable power provides some RA capacity, so the RA adder for the  
20 renewable portfolio would have to be reduced by the amount of RA value provided by  
21 the utility's net qualifying capacity (NQC). CLECA-CMTA also acknowledges that this  
22 process would involve yet another calculation by the Energy Division or a third-party  
23 consultant.

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<sup>26</sup> Joint Parties' Testimony – Part 1, pp. 12-18.

<sup>27</sup> Marin Independent Journal, "Marin Energy Authority signs deals to buy more power as it prepares to expand," dated January 24, 2011, by Richard Halstead, available at [http://www.marinij.com/sananselmo/ci\\_17186476](http://www.marinij.com/sananselmo/ci_17186476), accessed on February 15, 2011.

<sup>28</sup> CLECA-CMTA Testimony, pp. 11-12.

1 The CLECA-CMTA proposal is basically a modified version of the Joint Parties’  
2 proposal, with additional features for capturing the quantifiable benefits of long-term  
3 contracts and a different methodology for accounting for RA capacity. Despite these  
4 improvements, this proposal is still subject to some of the pitfalls of the Joint Parties’  
5 proposal, such as not including information from all LSEs, accuracy problems, and heavy  
6 reliance on analysis and verification by the Energy Division or a third party non-market  
7 participant. Therefore, DRA also opposes this proposal.

## 8 **5. L. Jan Reid Proposal**

9 L. Jan Reid recommends adopting the proposal in The Utility Reform Network’s  
10 (TURN) post-workshop comments which maintains the current MPB methodology such  
11 that the PCIA would incorporate the entire green attribute premium inherent in the IOUs’  
12 costs of procurement to meet the RPS goals, but non-utility retail suppliers would be  
13 given RPS credit for their proportionate share of the IOU’s RPS purchases.<sup>29</sup> As  
14 indicated in DRA’s post-workshop comments, this proposal was discussed and garnered  
15 considerable support at the workshop.<sup>30</sup>

16 Although this proposal avoids the difficult task of determining an appropriate  
17 market value for RPS resources, many logistical questions remain. Additional  
18 information is necessary to determine when and how the RPS credit transfer should  
19 occur, who should be responsible for any administrative and transactional costs that may  
20 arise, and whether the credit will count towards the 25% limit on REC usage. DRA  
21 request that more detailed information be provided to help answer these and other  
22 questions parties may have before the Commission seriously considers this proposal.

## 23 **B. Resource Adequacy Capacity Value**

24 DRA supports the idea of using accurate and publicly available, transparent data.  
25 However, DRA reiterates its concerns over using the maximum CAISO backstop price to  
26 determine the RA capacity value, in light of the fact that RA prices have been trading at

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<sup>29</sup> L. Jan Reid Testimony, pp. 11-12.

<sup>30</sup> Opening Comments of the Division of Ratepayer Advocates on Workshop Issues (DRA Opening Comments), January 14, 2011, p. 2.

1 well under the \$41/kW-year interim capacity procurement mechanism (ICPM) price.<sup>31</sup>  
2 DRA is also concerned by SCE's assertion that without a six month advance notice, it  
3 may not be possible to find a buyer for excess RA capacity in the absence of a short-term  
4 or spot market for RA capacity, so no value may be realized for the capacity.<sup>32</sup> SCE also  
5 indicated that the RA market is very illiquid and even with six months' advance notice it  
6 may not be possible to realize any value for the excess capacity. Therefore, DRA  
7 recommends the Commission reject the CAISO's ICPM as the market value for RA  
8 capacity. DRA is open to reviewing reasonable proposals for determining the value of  
9 RA capacity. However, in the absence of an alternate proposal, the current RA adders  
10 should remain in place.

### 11 **C. Load Profile Weighing of the Market Price Benchmark**

12 DRA understands there is a tradeoff between accuracy and transparency, but still  
13 prefers to maintain the current method of using publicly available, transparent data to  
14 determine the on-peak and off-peak weights for the MPB. PG&E and SCE propose using  
15 non-public IOU generation profiles to determine the on-peak and off-peak weights while  
16 acknowledging that generation profiles may differ by PCIA vintage due to a different  
17 generation mix. PG&E and SCE also acknowledge that calculating a different set of on-  
18 peak and off-peak weights for each PCIA vintage would be overly burdensome.<sup>33</sup>  
19 Therefore, PG&E and SCE suggest using only the current year weighting factor for all  
20 vintages for administrative ease. In DRA's view, under this proposal, nothing is gained,  
21 because the estimate will be accurate for the current PCIA vintage, but will be inaccurate  
22 for all other PCIA vintages.

23 There is no rationale for switching from publicly available, transparent data to  
24 confidential data, if it does not result in a more accurate estimation. Administrative ease  
25 is not an acceptable justification for reducing the number of calculations, and thus

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<sup>31</sup> DRA Testimony, pp. 5-6.

<sup>32</sup> SCE Testimony, p. 8.

<sup>33</sup> PG&E Testimony – Chapter 1, p. 15, and SCE Testimony, pp. 27-28.

1 reducing the accuracy of the estimation. The Commission should only consider using  
2 confidential IOU generation profiles if the actual on-peak and off-peak weights for each  
3 PCIA vintage were calculated. (It is also important to note that this same problem exists  
4 under the Joint Parties’ proposal to use the confidential IOU bundled load profiles as  
5 opposed to the confidential IOU generation profiles.)<sup>34</sup>

6 **D. ESP Financial Security Requirement**

7 The most contentious ESP financial security requirement issues are: (1) what  
8 should be included in the “re-entry fees” referenced in Public Utilities (PU) Code Section  
9 394.25(e) and, (2) who should be responsible for paying the re-entry fees? DRA believes  
10 a resolution on the legal issues will resolve the issue surrounding who is responsible for  
11 the re-entry fees and provide guidance on which bonding methodology is the most  
12 appropriate and reasonable.

13 Despite the absence of a resolution on the legal issues, the parties’ testimony  
14 suggests that the administrative fees imposed by the utility for implementing the  
15 customer’s change of service request should be included in the re-entry fees. The parties’  
16 testimony also suggests that the incremental cost of TBS rates should either be included  
17 in the re-entry fees or be paid for directly by the involuntarily returned customer. Some  
18 parties stated that the TBS rate essentially served the same purpose as a re-entry fee but is  
19 not technically a re-entry “fee” for which the bond amount should cover. It is also  
20 important to note that RA and RPS costs will be accounted for and don’t need to be  
21 included in the re-entry fees, since the parties have agreed to update the TBS rates to  
22 reflect RA and RPS charges.

23 Although there is some agreement among parties as to the incremental cost of TBS  
24 rates, disagreement remains over the TBS rate duration. SCE and SDG&E argue that the  
25 TBS rate duration should be extended to a year, since the cost impact of a mass  
26 involuntary return of DA customers to IOU procurement service can extend well beyond

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<sup>34</sup> Joint Parties’ Testimony – Part 1, pp. 29-30.



1 the price of the TBS rate for six months, or even one year.<sup>35</sup> A one-year TBS period is  
2 also consistent with the one-year advance written notice requirement to the Commission  
3 and IOU of the CCA’s intention to discontinue its CCA service.<sup>36</sup> CLECA-CMTA and  
4 the Joint Parties argue that the TBS rate duration should only be six months to be  
5 consistent with the TBS duration of customers returning to bundled service voluntarily  
6 without six months’ advance notice.<sup>37</sup> CLECA-CMTA also argue that the high utility  
7 reserve margins forecasted for the IOUs would limit the risk of insufficient supplies to  
8 serve a mass return of DA customers to bundled service. On the other hand, CLECA-  
9 CMTA did not address the potential impact on the IOU’s RA and RPS requirements,  
10 which are expected to increase as total load served increases.

11 The ESP bonding methodology proposals appear to be split by the expected  
12 outcome on the legal issues pertaining to the ESP financial security requirements. The  
13 CLECA-CMTA, Joint Parties, and SDG&E proposals all assume that the IOUs are  
14 permitted to place involuntarily returned customers on the TBS rate, so the re-entry “fee”  
15 is limited to the administrative fees. The PG&E and SCE proposals assume that  
16 involuntarily returned customers must be placed on the same bundled service rate as  
17 other bundled customers immediately; in their view, the re-entry “fee” must cover both  
18 the administrative fees and the incremental cost of going on the TBS rate. In DRA’s  
19 view, in instances where DA customers are involuntarily returned to bundled service as a  
20 result of the ESP unilaterally discontinuing DA service, the ESP, not the DA customers,  
21 should be responsible for all re-entry fees and incremental costs. Involuntarily returned  
22 DA customers should not be penalized for circumstances beyond their control. DRA  
23 recommends that at a minimum, the bonding requirement be sufficient to cover the  
24 administrative fees and incremental cost of TBS rates.

25 Regardless of how the legal issues are resolved, all parties agree that the purpose  
26 of the bonding requirement is to prevent cost shifting to bundled customers in the event

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<sup>35</sup> SCE Testimony, pp. 43-45 and SDG&E Testimony – Chapter 1, pp. 7-8.

<sup>36</sup> PG&E Electric Rule No.23.S, SCE Electric Rule No. 23.S, and SDG&E Electric Rule No. 27.S.

<sup>37</sup> CLECA-CMTA Testimony, pp. 22-24 and Joint Parties’ Testimony – Part 2, pp. 14-17.

1 customers are involuntarily returned to bundled service. DRA believes all CCA/DA  
2 customers should be informed of all risks and costs associated with CCA/DA service  
3 prior to signing up. In the event the Commission determined that involuntarily returned  
4 customers are responsible for the incremental cost of TBS rates, DRA urges the  
5 Commission to order the IOUs to inform all potential and existing CCA/DA customers  
6 that they will be responsible for the incremental cost of TBS rates in the event they are  
7 involuntarily returned to bundled service. This will ensure that customers are aware of  
8 the risks prior to signing up and provide ample time for existing CCA/DA customers to  
9 provide six months' advance notice and return to bundled service voluntarily.

10

11

# **APPENDIX A**

1                                   **QUALIFICATIONS AND PREPARED TESTIMONY**  
2                                                           **OF**  
3                                                           **KE HAO OUYANG**  
4

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

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

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

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

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

13   A.3.   I received a Bachelor of Arts Degrees in both Applied Mathematics and  
14           Economics from the University of California, Berkeley in 2005.

15           I joined the Electric Pricing and Consumer Program Branch of the Division of  
16           Ratepayer Advocates in June 2010, and work on Community Choice Aggregation,  
17           Direct Access, and Demand Response related issues.

18   Q.4.   What is your area of responsibility in the Direct Access proceeding?

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

20   Q.5.   Does this conclude your reply testimony?

21   A.5.   Yes, it does.

**CERTIFICATE OF SERVICE**

I hereby certify that I have this day served a copy of the foregoing document  
**“REPLY 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”** in **R.07-05-025**.

A copy was served as follows:

**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 in San Francisco, California, on the **25** day of **February, 2011**.

/S/ MARTHA PEREZ

\_\_\_\_\_  
Martha Perez