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

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I. INTRODUCTION

In accordance with the Assigned Commissioner's Ruling Adopting Amended Scoping Memo and Schedule (ASM) issued on November 22, 2011, and per the Administrative Law Judge Thomas Pulsifer's Ruling Amending Procedural Schedule issued on January 7, 2011, the Division of Ratepayer Advocates (DRA) submits this 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.

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

II. SUMMARY OF RECOMMENDATIONS

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

PCIA Issues:

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

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

III. DISCUSSION

PART 1: POWER CHARGE INDIFFERENCE ADJUSTMENT

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

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

[1] 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.

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

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

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

1. Value of Non-RPS Eligible Resources

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

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

2. Value of RPS Eligible Resources

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

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

B. Replace Fixed Resource Adequacy/Capacity Adders with Capacity Costs

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

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

[2] D.06-07-030, pp 10-13.

[3] D.07-01-030, pp 3-5.

[4] 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).

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

C. Remove Load Related CAISO Costs From Total Portfolio Costs

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

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

D. Short Term Energy Market Transactions

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

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

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

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

E. Load Profile Weighing of the Market Price Benchmark

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

[5] D.08-09-012, pp 64-68.

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

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

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

[6] D.04-12-048, pp 55-63.

F. Continuous Direct Access Customers

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

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

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[7] D.02-11-022, pp 4-5, 60-64.

[8] D.06-07-030, pp 25-28.

PART 2: ESP FINANCIAL SECURITY REQUIREMENT

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

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

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

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

PART 3: DIRECT ACCESS SWITCHING RULES

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

Commission Decision D.03-05-034[9] determined that, when a DA customer is involuntarily returned to bundled service as a result of the ESP unilaterally discontinuing DA service, the DA customer may enter the 60-day "safe harbor" without having an immediate candidate for a new ESP. The temporary safe harbor allows the customer to continue receiving service while switching from one ESP to another but is required to pay the applicable TBS rate. If a Direct Access Service Request (DASR) is not submitted by the end of the 60 days, the customer will be returned to bundled service and becomes subject to the same pricing terms and conditions as apply to other bundled customers. The bonding requirement will ensure that any costs associated with involuntary returns are not shifted to bundled customers. Since the bonding requirements are intricately interwoven with the switching rules, modifications to the bond calculation methodology may warrant revising the switching rules. DRA is open to reviewing reasonable proposals and will address these proposals in reply testimony.

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[9] D.03-05-034 pp 18-23.

PART 4: TRANSITIONAL BUNDLED SERVICE RATE

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

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

Only the Joint Utilities' proposal to adjust the TBS rates to reflect RA and RPS charges using energy and capacity scalars was discussed at length at the workshops.[10] The energy scalar is the ratio of the weighted average MPB to the market value of non-RPS resources. The capacity scalar is ratio of the market value of non-RPS resources plus the market value of capacity to the market value of non-RPS resources. The TBS rates will be multiplied by both the energy and capacity scalars to reflect RA and RPS charges. DRA finds this proposal reasonable and supports it.

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[10] *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.

Appendix A
Qualifications and Prepared Testimony of Ke Hao Ouyang

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

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

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

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

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

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

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

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

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

Q.5. Does this conclude your opening testimony?

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:.

[**X**] **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

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