Direct Testimony of L. Jan Reid on Phase III Direct Access Issues

R.07-05-025

Served January 31, 2011
on behalf of
L. Jan Reid

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Pursuant to the procedural schedule set forth in the November 22, 2010 Assigned Commissioner's Ruling (ACR) of Commissioner Michael Peevey, I submit this direct testimony on behalf of myself. I am a customer of Pacific Gas and Electric Company (PG&E) and am a party in this proceeding. In the testimony, I discuss the recommendations of the investor owned utilities (IOUs)[1] as well as the Joint Parties,[2] who represent direct access interests. In rebuttal testimony and briefs, I may take positions on issues not addressed herein. The testimony is supported by workpapers that are available on request.

I will sponsor all testimony in this document. All calculations in this document are illustrative and are subject to change.

My qualifications are set forth in Appendix A.

I. Summary

This proceeding is similar to a cost-of-capital case or a general rate case in at least one respect. In its decision, the Commission must decide on a numerical indifference rate as well as determine various tariff rates. The Commission should evaluate the evidence before it, and consider both quantitative and qualitative factors in reaching a judgment. This proceeding is not just a numerical exercise or the evaluation of the quality of a particular model. The Commission must also consider issues of fairness, consumer protection, and competitiveness.

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[1] The IOUs in this proceeding are Pacific Gas and Electric Company, San Diego Electric & Gas Company (SDG&E), and Southern California Edison Company (SCE).

[2] The Joint Parties are the Marin Energy Authority, the Direct Access Customer Coalition, the Alliance for Retail Energy Markets, the City and County of San Francisco, the California State University, the California Municipal Utilities Association, Commercial Energy, Pilot Power Group, Inc., Energy Users Forum, BlueStar Energy, San Joaquin Valley Power Authority, the School Project for Utility Rate Reduction and the Retail Energy Supply Association.

The ACR has identified the following issues as within the scope of Phase III of this proceeding. These issues are:

- The Power Charge Indifference Amount (PCIA)
- The Transitional Bundled Service Rate
- Direct Access Switching Rules
- Energy Service Provider (ESP) Security Issues

A workshop on technical issues in this rulemaking was conducted as a series of four sessions (on December 7, December 14, and December 15, 2010, and on January 4, 2011). At the workshop, a number of parties made presentations concerning the issues listed above.

I discuss some of these issues in Sections III-VI below.

II. Recommendations

I have relied on state law, past Commission decisions, and information furnished by the IOUs and the Joint Parties in developing recommendations on the outstanding Phase III direct access (DA) issues. Page references are given in parentheses after each recommendation or finding.

I recommend the following:

1. The Commission should consider both quantitative and qualitative factors in reaching a decision on Phase III DA issues. (pp. 4-6)

2. The Commission should establish DA rules in this proceeding which will not increase the rates of residential ratepayers. (p. 6)

3. The Commission should not adopt a renewable adder to the market price benchmark as suggested by TURN. Instead, the Commission should find that DA providers should receive RPS credit for their proportional share of the IOUs RPS purchases. (pp. 9-12)

4. The Commission should order all three IOUs to use a capacity price of $41/kilowatt-year in calculating the Market Price Benchmark (MPB). The capacity price should be changed if the California Independent System Operator (CAISO) changes the capacity price used in its Capacity Procurement Mechanism. (pp. 12-13)

5. The Commission should find that volumetric CAISO load charges should not be accounted for in the PCIA. (pp. 14-14)

6. The Commission should find that publicly available data should be used to calculate the MPB and PCIA in this proceeding. (pp. 14-15)

7. The PCIA should not be allowed to be negative. (pp. 16-16)

My recommendations are based on the following proposed findings:

1. Residential customers pay higher rates per kilowatt hour than large commercial and industrial customers. (p. 5)

2. Any recoverable cost faced by the utility is ultimately paid for by the utility's bundled customers. (p. 4)

3. Public Utilities Code §365.1(a) specifically prohibits the vast majority of residential customers from receiving service from a direct access provider. (p. 4)

4. Direct access customers typically pay a contractually agreed-upon rate for the electricity commodity. (p. 4)

5. Under the current system, bundled residential ratepayers subsidize direct access customers. (p. 6)

6. If the Market Price Benchmark (MPB) increases and Total Portfolio Costs (TPC) remains the same, DA rates will decrease and bundled customer rates will increase relative to rates in the previous year. (p. 7)

7. In 2011, residential customers will pay 41.65% of PG&E's total bundled customer revenue requirement and 38.60% of PG&E's bundled customer generation revenue requirement. (p. 5)

8. TURN's RPS recommendation would contribute to bundled ratepayer indifference because bundled ratepayers would neither gain nor lose. (p. 12)

9. The CAISO capacity price is transparent, publicly available, and can be used to update the MPB if the CAISO price changes. (p. 13)

10. When rates increase, bundled ratepayers should have the right to inspect the data; and to know why rate increases are necessary and how these rate increases are calculated. (p. 15)

11. If the Commission allows the PCIA to be negative, this would imply that the Commission believes that bundled ratepayers receive a benefit from customers switching from bundled service to direct access. (p. 16)

III. Residential Ratepayers

This section will discuss the ways in which bundled residential customers are treated differently than commercial and industrial customers. I note that Public Utilities Code §365.1(a) specifically prohibits the vast majority of residential customers from receiving service from a direct access provider. Thus, residential customers cannot partake of the benefits (if any) of direct access.

Additionally, any recoverable cost faced by the utility is ultimately paid for by the utility's bundled customers. This is not true in the case of direct access customers, who typically pay a contractually agreed-upon rate for the energy commodity.

SCE has stated that: (SCE Response to Question 2 of Reid's First Set of Discovery Questions)

> SCE's Transitional Bundled Rate, which DA customers can take service on when switching back to utility procurement service, does not account for Resource Adequacy costs incurred by the utility for the load served on TBS.
>
> SCE also faces incremental procurement costs (energy, Resource Adequacy, Renewable Portfolio Standards, and greenhouse gas emissions reductions compliance costs) as well as incremental utility administrative costs in the event of an involuntary return of DA customers to SCE procurement service, which are not appropriately accounted for in the current switching rules.

There are other ways in which residential customers are treated differently than commercial and industrial customers. Three of these differences are:

1. Residential customers pay higher rates per kilowatt hour than large commercial and industrial customers. (See Table 1)

Table 1: 2010 Systemwide Average Rates (cents/kwh) by Utility and Customer Class

Customer Class	PG&E	SCE	SDG&E
Residential	16.3	15.9	17.7
Small and Medium Commercial	16.9	15.3	17.7
Large Commercial and Industrial	12.6	10.8	14.2
Agricultural	14.2	11.5	17.2
Street Lighting	16.2	19.2	15.5
System Average	15.3	14.3	15.9

Source: California Public Utilities Commission, "Rates and Chart Tables", http://www.cpuc.ca.gov/PUC/energy/Electric+Rates/ENGRD/ratesNCharts_elect.htm.

2. In 2011, residential customers will pay 41.65% of PG&E's total bundled customer revenue requirement and 38.60% of PG&E's bundled customer generation revenue requirement.[3]

3. Businesses, but not residential ratepayers, can take advantage of lower economic development rates. Economic development rates apply to "All customers above 200 kW, except state and local government and residential customers." (D.05-09-018, slip op. at 7)

[3] Calculated from data provided in PG&E Advice Letter 3727-E-A, Table 3.

The facts discussed above constitute a subsidy of direct access customers by bundled ratepayers and in particular by bundled residential customers. Therefore, the Commission should establish DA rules in this proceeding which will not increase the rates of residential ratepayers. As mentioned above, the Commission should consider qualitative factors when reaching a decision in this case. One of those factors should be the existing status of different customer classes with respect to direct access.

IV. The DA Load Cap

In 2010, the Commission set a load cap which restricts the amount of load that can switch from bundled utility service to service from an energy service provider (ESP) or community choice aggregator. (Decision (D.) 10-03-022, slip op. at 7). This is typically referred to as DA load increase. In Table 2, I give the DA load increase in gigawatt hours (GWh) for each IOU.

Table 2: Total DA Load Increase (GWh) by IOU

Item	PG&E	SCE	SDG&E
Load Cap pursuant to SB 695	9,520	11,710	3,562
− Existing baseline DA	5,574	7,764	3,100
= New DA Load Allowance	3,946	3,946	462

The DA Load Increase took effect on April 11, 2010, with DA load being phased in over a four-year period. The Commission has explained that the annual limit (in kWh) is: (D.10-03-022, Appendix 2, slip op. at 1)

Y1 (2010): 35% of the current room available under the DA cap.

Y2 (2011): An additional 35% of the current room available under the cap (or 70% of the available room under the DA cap).

Y3 (2012): An additional 20% of the current room available under the cap (or 90% of the available room under the DA cap).

Y4 (2013): An additional 10% of the current room available under the cap (or 100% of the available room under the DA cap).

I use the DA Load Increase in my estimate of the cost of different proposals. (See Section V.A). For purposes of calculating RPS costs for the years 2011-2013, I assume that 35% of the load allowance was used during the year 2010. In Table 3, I give the adjusted DA load increase in gigawatt hours (GWh) for each IOU for the years 2011-2013.

Table 3: 2011-2013 DA Load Increase (GWh) by IOU

Item	PG&E	SCE	SDG&E
Initial DA Load Allowance	3,946.0	3,946.0	462.0
− 2010 Allocation	1,381.1	1,381.1	161.7
= Remaining Allocation	2,564.9	2,564.9	300.3

V. The Power Charge Indifference Amount

The Power Charge Indifference Amount (PCIA) is the difference between the cost of an IOU's supply portfolio (Total Portfolio Costs) and the market value of the supply portfolio (the Market Price Benchmark). Customers who switch from bundled service to direct access (departing customers) are responsible for their pro-rata share of the PCIA. If the Market Price Benchmark (MPB) increases and Total Portfolio Costs (TPC) remains the same, DA rates will decrease and bundled customer rates will increase relative to rates in the previous year.[4]

[4] This assumes that all other factors (e.g., CTC, fuel prices, etc.) are held constant.

The IOUs have explained that: (Joint SCE/PG&E Proposed Modification of Indifference Amount Calculation, p. 2)

1. Pursuant to D.06-07-030 (as modified), the utility develops an "indifference amount" annually in its Energy Resource Recovery Account (ERRA) forecast proceeding.

2. For each vintage year, the utility calculates the cost of the total portfolio of all generation resources assigned to that year. The generation portfolio for each vintage year includes all resources and contracts entered into to serve bundled load for that year.

3. Energy Division produces a market price benchmark (MPB) for the forecast year, which includes the value of energy (average price of a 12-month forward strip), the value of Resource Adequacy (RA) capacity in $/megawatt hour ($/MWh),[5] and an adjustment for line losses per MWh

4. Each portfolio is valued at the MPB to produce a market cost (in $/MWh) for the total portfolio.

5. The market cost of the portfolio is subtracted from the total portfolio cost for each year to determine any above-market costs. This is referred to as the "indifference amount," which can either be positive or negative under the current system.[6]

6. Statutory Competitive Transition Charge (CTC) revenue is subtracted from the indifference amount to produce the PCIA amount.

7. CTC and PCIA revenue requirements are allocated to individual rate groups using the top 100-hours method to determine rates.[7]

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[5] I discuss Capacity value in Section IV.B.

[6] The IOUs have proposed that zero be used as the indifference amount if the calculated indifference amount is negative.

[7] The top 100-hours method refers to the top 100 hours of demand from customer classes with historic information for a certain period. These demand statistics would form the basis for certain cost allocations between customer classes.

The City and County of San Francisco (CCSF) has explained that: (Testimony of Margaret Meal, A.10-05-022, p. 5)

> Under the current method, an "Indifference Amount" is determined for the total portfolio of resources (PCIA and CTC), using the Market Price Benchmark. Any above-market costs associated with the CTC resources are determined using the same Market Price Benchmark, and those costs are subtracted from the indifference Amount to determine the PCIA revenue requirement. So the total portfolio, the PCIA portion and the CTC portion, are all valued using the same Market Price Benchmark.

A. Renewables Portfolio Standard (RPS)

Renewable Energy Credits (RECs) are currently not included in the Market Price Benchmark. The IOUs have proposed that: (Joint SCE/PG&E Proposed Modification of Indifference Amount Calculation, p. 4)

- A MPB adder be used to incorporate the value of renewable energy in the portfolio using publicly available data.
- As an interim measure, the U.S. Dept. of Energy's survey of reported contract premiums for renewable energy in the Western U.S. should be used as a proxy for the value of renewable energy in the MPB.
- When a transparent market exists for California compliance RECs exists, the traded value of California RECs should be used.
- The MPB should be weighted, before loss adjustment, based on the proportion of the total energy portfolio supplied by RPS eligible renewable energy.
- Pre-2003 resources (legacy Qualifying Facilities priced at avoided cost) should be excluded from the calculation of the MPB.

For 2011 vintage contracts, SCE estimate that the indifference rate will increase from $21.13 to $29.25 if renewables are included in the PCIA calculations. (SCE Answer to Question 5 of ED Discovery Request)

SDG&E estimates that the MPB would increase from $53.75/MWh to $55.99/MWh if renewables are included in the calculation. (SDG&E Response to Energy Division Question 5) In footnote 2 of its estimate, SDG&E states that:

> RPS energy, since it is must take, is also replaced one for one with conventional resource energy. Also assumes that marginal resources will remain unchanged between this and the base case. This is not necessarily true but, even so, the expectation is that there will not be a dramatic shift between peak and off peak generation as a result. So the on and off peak weighting of the forward prices should remain relatively similar. Refinement to this calculation, it will require a new production cost model run and more time. (SDG&E spreadsheet "DirectAccessReopeningOIR_DR-ED_001-Q2&5.xls" in the '2010 benchmark – response to 2" tab)

Table 4 provides the cost of 2009 RPS resources for each IOU.

Table 4: Price Paid by IOUs for RPS Energy and Capacity in 2009

IOU	Energy Price ($/MWh)	Capacity Price ($/MWh)	Total Price ($/MWh)
PG&E [1,2]	61.78	9.53	71.32
SCE [3]	61.75	20.34	82.09
SDG&E [4,5]	61.59	0.32	61.91

Notes:

1. PG&E 2009 FERC Form 1 Purchase Power Data.
2. The capacity price was calculated by dividing the total price paid for capacity by the number of MWh procured. Of the 9,911 GWh of RPS energy PG&E purchased in 2009, a capacity price was paid on 4,406 GWh. The capacity price on these contracts averaged $21.44/MWh.
3. SCE 2009 FERC Form 1 Purchase Power Data
4. SDG&E 2009 FERC Form 1 Purchase Power Data
5. The capacity price was calculated by dividing the total price paid for capacity by the number of MWh procured. Of the 1,450 GWh of RPS energy SDG&E purchased in 2009, a capacity price was paid on one 28-GWh contract. The capacity price for this contract was $16.33/MWh.

Three parties have made recommendations concerning a RPS adder to the MPB: The IOUs, the Joint Parties, and TURN. The IOUs recommend that the RPS adder be equal to the DOE premium. The Joint Parties recommend that the RPS adder be equal to the cost of renewables in a given year. TURN has explained that: (TURN Post Workshop Comments, p. 4)

> Under this [TURN's] proposal, utility renewable procurement costs would be included in the total portfolio, but the MPB would NOT be revised to include a renewable component. Thus, the PCIA would incorporate the entire green attribute premium inherent in the IOUs' costs of procurement to meet the RPS, but non-utility retail suppliers would be given RPS credit for their proportionate share of the IOU's RPS purchases (for those renewable contracts entered into after the original enactment of the RPS legislation).

In Table 5, I provide an estimate of the effect of each party's recommendation on the PCIA of each IOU.

Table 5: Effect of RPS Recommendations on PCIA for the Years 2011-2013

IOU	IOUs	Joint Parties[8]	TURN
PG&E PCIA ($/MWh)	−3.82	-71.32	0.00
PG&E Change in PCIA ($ Million)	−9.80	-26.34	0.00
SC&E PCIA ($/MWh)	−4.18	−17.21	0.00
SCE Change in PCIA ($ Million)	−10.73	-44.13	0.00

[8] I assume that (a) the Joint Parties are recommending that the renewable adder be equal to the average price paid by each IOU as shown in Table 4, and (b) the RPS weight for PG&E is 14.4% as stated in the CPUC's "Renewable Portfolio Standard Quarterly Report, 4th Quarter 2010.

IOU	IOUs	Joint Parties[8]	TURN
SDG&E PCIA ($/MWh)	−2.40	−7.43	0.00
SDG&E Change in PCIA ($ Million)	−0.72	−2.23	0.00

Under TURN's recommendation, there would be no renewable adder, but DA providers would receive RPS credit for their proportional share of the IOUs RPS purchases. Thus, there would be no immediate change in the PCIA but ratepayers would lose RPS credit which would have to be made up in a future period. However, the RPS requirement would decrease because load has declined.

TURN's recommendation would contribute to bundled ratepayer indifference because bundled ratepayers would neither gain nor lose. As shown in Table 5, this is not true of the proposals of either the IOUs or the Joint Parties. TURN's proposal is fair to bundled ratepayers, and fair to direct access customers. Therefore, I recommend that the Commission adopt TURN's RPS proposal.

B. Capacity Value

The capacity value is used in the calculation of the MPB. The capacity value is currently set at $7/MWh for SCE and $4/MWh for PG&E. The IOUs have proposed that: (Joint SCE/PG&E Proposed Modification of Indifference Amount Calculation, p. 3)

- The capacity adder should be based on the price set in the CAISO's Interim Capacity Procurement Mechanism (ICPM) (to be superseded by

Capacity Procurement Mechanism (CPM) in effect when the annual MPB is calculated.[9]

- The existing energy adder for capacity should be removed and the market cost calculation of the total portfolio should be adjusted by multiplying procured, net qualifying capacity (MW), by vintage, by the CPM.

The CAISO capacity price is currently set at $41/kW-yr. The CAISO proposed CPM of $55/kW-yr is pending. $55/kW-year is equivalent to $6.28/MWh. Thus, PG&E's capacity value would increase by $2.28/MWh and SCE's would decline by $.72/MWh.

I am concerned that the IOUs' capacity proposal would effectively increase costs for PG&E ratepayers and decrease costs for SCE ratepayers. However, the use of the CPM price has a number of advantages which are more important than the effect of incremental rate discrimination between ratepayers of PG&E and SCE. These advantages include:

1. It replaces a capacity price "based on the annual capital costs for a combustion turbine generator"[10] with a price which is used in the CAISO's markets.
2. The CAISO capacity price is transparent, publicly available, and can be used to update the MPB if the CAISO price changes.
3. I am unaware of any good reason why there should be a $3/MWh difference between capacity owned by PG&E and capacity owned by SCE.

Therefore, I recommend that the Commission initially adopt a capacity price of $41/kw-year. If the CAISO changes the capacity price used in the CPM, the Commission should change the capacity price used in the MPB.

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[9] The CAISO capacity price is currently set at $41/kilowatt-year.

[10] D.06-07-030, slip op. at 8.

C. CAISO Costs

Both the IOUs and the Joint Parties agree that CAISO load charges should be excluded from the total cost portfolio and thus will not be accounted for in the PCIA. I agree with these parties for the reasons discussed below:

One of the purposes of the PCIA is to attempt to make sure that bundled ratepayers are indifferent to the movement of load from the IOUs to direct access providers. Since many of the CAISO load charges are based on volume, they should not be paid for by direct access providers.

Therefore, I recommend that the Commission find that volummetric CAISO load charges should not be accounted for in the PCIA.

D. Load Profiles

The Joint Parties have explained that: (Workshop Report of the Joint Parties, January 14, 2011, pp. 5-6)

> The Joint Parties proposed that the forwards-based portion of the MPB be load-weighted based on the bundled customer load profile. (See presentations #3 and #8.) The IOUs responded that the weighting be based upon its "generator profile," which includes only the production profile of the long-term resources (i.e., it does not include the contribution of any spot- or short-term purchases.)

The IOUs have argued that "The existing method correctly produces lower indifference amounts for rate groups with proportionately lower consumption of peak resources, consistent with rate design of generation charges for bundled customers." (Joint SCE/PG&E Proposed Modification of Indifference Amount Calculation, p. 7)

I agree with the IOUs that the existing methodology should not be changed. Whenever possible, the Commission should authorize the use of publicly available data in calculating the MPB and PCIA. The bundled customer load profile is confidential and thus will not be available to the public or to many of the parties in this proceeding.

This proceeding is not merely a disagreement between the IOUs and the direct access parties. When rates increase, bundled ratepayers should have the right to inspect the data; and to know why rate increases are necessary and how these rate increases are calculated.

The Bagley-Keene Open Meeting Act states that: (Government Code §11120)

> The people of this state do not yield their sovereignty to the agencies which serve them. The people, in delegating authority, do not give their public servants the right to decide what is good for the people to know and what is not good for them to know. The people insist on remaining informed so that they may retain control over the instruments they have created.

The Commission has also indicated a clear preference for publicly available data. The Commission has stated that "We start with a presumption that information should be publicly disclosed and that any party seeking confidentiality bears a strong burden of proof." (D.06-06-066, as modified by D.07-05-032, Appendix A, p. 2)

For the reasons discussed above, I recommend that the Commission find that publicly available data should be used to calculate the MPB and PCIA in this proceeding.

VI. CTC

PG&E has recommended that: (Indifference Calculation Modification, p. 2, December 7, 2010 workshop proposal)

> Specifically, the PCIA should be constrained such that if the Indifference Result minus the ongoing CTC is less than or equal to zero, then the PCIA should be set = 0. The PCIA rate already has a constraint that the absolute value of any negative PCIA result cannot be greater than the ongoing CTC.

I agree with PG&E that the PCIA should not be allowed to be negative. If the Commission allows the PCIA to be negative, this implies that bundled ratepayers receive a benefit from customers switching from bundled service to direct access. This is clearly not true. If the Commission designed the perfect system, bundled ratepayers would simply be reimbursed for all of the costs that they face as a result of direct access. I am unaware of any convincing evidence submitted in this proceeding which shows that bundled ratepayers receive a net benefit due to the activities of direct access providers. For example, no party has introduced evidence which shows that an increase in DA reduces the rates paid by bundled ratepayers.

VII. Conclusion

The Commission should adopt my recommendations for the reasons given herein.

This completes my direct testimony. A statement of qualifications is given in Appendix A.

APPENDIX A
WITNESS QUALIFICATIONS

QUALIFICATIONS AND PREPARED TESTIMONY OF L. JAN REID

My name is L. Jan Reid. My business address is 3185 Gross Road, Santa Cruz, CA 95062. I retired from the California Public Utilities Commission (CPUC) in June 2005, and am now working as sole proprietor of Coast Economic Consulting, and as a consulting economist and expert witness.

I hold a Bachelor of Arts degree in Economics and a Masters of Science degree in Applied Economics and Finance from the University of California, Santa Cruz. The subject of my master's thesis was whether the Capital Asset Pricing Model (CAPM) is a biased estimator of market risk.

I was employed at the Commission in the Office of Ratepayer Advocates from 1998 to 2005. I sponsored written testimony on cost of capital, electric procurement, risk management, and credit ratings. I made presentations in Commission workshops, developed econometric models, and provided internal financial and economic analysis in proceedings related to market power, electric procurement, operations support services, asset valuation, performance-based ratemaking (PBR) proposals, and utility service quality.

Since leaving the Commission, I have represented myself and Aglet Consumer Alliance in procurement review groups (PRGs) for Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company. I have participated in formal proceedings involving cost of capital, renewables portfolio standards, long-term procurement contracting, resource adequacy, and demand-response programs.

This completes my statement of qualifications.

CERTIFICATE OF SERVICE

I certify that I have this day by electronic mail served a true copy of the original attached "Direct Testimony of L. Jan Reid on Phase III Direct Access Issues" on all parties of record in this proceeding or their attorneys of record. I will serve a paper copy of the pleading on Commissioner Michael Peevey, and on Administrative Law Judge Thomas Pulsifer.

Dated January 31, 2011, at Santa Cruz, California.

/s/

L. Jan Reid