BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Rulemaking Regarding Whether, or Subject to What Conditions, the Suspension of Direct Access May Be Lifted Consistent with Assembly Bill 1X and Decision 01-09-060.	Rulemaking 07-05-025 (Filed May 24, 2007)

OPENING COMMENTS OF JOINT PARTIES ON PROPOSED DECISION OF ADMINISTRATIVE LAW JUDGE PULSIFER ON DIRECT ACCESS REFORMS

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AND ON BEHALF OF THE JOINT PARTIES

Dated: September 12, 2011

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In accordance with California Public Utilities Commission Rules of Practice and Procedure, Rule 14.3, the Joint Parties[1] submit these opening comments on the *Proposed Decision of Administrative Law Judge ("ALJ") Pulsifer on Direct Access Reforms* ("PD").

I. Introduction and Summary

These comments address only issues associated with modifications to the calculation of the Indifference Amount, and the Market Price Benchmark ("MPB") used to calculate the Power Charge Indifference Amount ("PCIA") and the Competition Transition Charge ("CTC"). Individual members of the Joint Parties may individually or in different combinations file comments on other issues in the PD. While the Joint Parties identify certain errors that require correction with respect to the PD's reforms to calculation of the Indifference Amount, the PCIA and CTC, the Joint Parties are generally supportive of the PD with respect to PCIA issues. In particular, the PD properly identifies several fundamental flaws in the current calculations, including: the failure to factor in the value of renewable resources in the MPB; the fact that the

[1] The Joint Parties are Marin Energy Authority ("MEA"), the California Municipal Utilities Association, the City and County of San Francisco ("CCSF"), San Joaquin Valley Power Authority, Alliance for Retail Energy Markets ("AReM"), Direct Access Customer Coalition ("DACC"), BlueStar Energy, Pilot Power Group, Inc., and the Retail Energy Supply Association ("RESA").

current methodology does not provide for updating of the capacity value used to calculate the MPB; the failure to accurately factor in the value of the shape of the IOUs' supply portfolios in calculating the MPB; and the need to exclude load-based CAISO charges from the Total Portfolio Cost. In addition, the PD properly concludes that Pacific Gas and Electric Company's ("PG&E's") proposal to artificially limit CTC at no less than zero would violate bundled customer indifference.

However, as explained more fully below, the PD errs in including the value of renewables purchased by non-IOU buyers in the calculation of the value of IOU renewables and in the use of United States Department of Energy ("DOE") data on western regional renewable energy contract premiums to value those renewables purchased by non-IOU buyers. In addition, there are several other aspects of the PD's reforms to calculation of the Indifference Amount and the MPB that should be clarified. Finally, the PD seemingly conflicts with the Administrative Law Judge's earlier ruling with regard to how the revised PCIA would be implemented, providing not for a refund but rather for a prospective credit; this element of the PD should be corrected.

The Joint Parties also urge the Commission to clarify the PD to provide that the changes to the indifference amount calculation adopted in the PD apply to the MPB used to calculate CTC as well as the PCIA. In particular, changes to the MPB -- to reflect the value of renewables and the value of the shape of the supply portfolio, and, if any are adopted, to update the value of capacity -- should be made irrespective of whether the MPB is used to calculate CTC or the PCIA. The Joint Parties believe this to be the intent of the PD since there are numerous references to a change to the calculation of the indifference amount, a term that encompasses both the PCIA and CTC, and because the current methodology uses the same MPB methodology for the indifference amount, PCIA and CTC.

There is in fact no justification for a distinction between the two and it would be absurd to use a more accurate MPB for purposes of calculating PCIA, and an outdated, understated MPB for purposes of calculating CTC. Nonetheless, during the proceeding various parties suggested at one time or another that the corrections to the MPB should apply only to the PCIA so this matter should be made clear in the final decision.

In Appendix A, the Joint Parties have made suggested changes to the finding of fact, conclusions of law and the ordering paragraphs to correct the errors and achieve the clarifications recommended in these comments. Appendix A does not address matters other than corrections to calculation of the Indifference Amount and the MPB.

II. The PD Appropriately Values Renewables Procured by the IOUs but Needlessly Errs in Determining that Procurement by Non-IOUs Must Be Included in the Valuation and in Using an Inaccurate Measure to Value Renewables Procured by Non-IOUs.

The Proposed Decision includes three very important findings and determinations with respect to renewable resources that are amply supported by the record. Findings of Fact 5 and 6 accurately provide that "[t]he current indifference methodology only recognizes the IOUs' cost of renewable resources in the calculation of the Total Portfolio Cost, but does not account for the market value of renewable resources in the MPB" and "[a]n adjustment to the MPB to account for the market value of renewable resources will result in a more accurate measure of indifference costs."[2] The PD also properly directs that pre-2004 resources be included in the RPS adder calculation because all IOUs claim RPS compliance credit for pre-2004 renewable resources.[3]

The PD concludes, however, that none of the proposals for valuing renewables in the IOUs portfolios is adequate, and adopts a methodology that combines two proposals, that of the

[2] PD at 94.
[3] PD at 23.

Joint Parties and that proposed by San Diego Gas and Electric Company ("SDG&E"). First, the PD adopts a methodology that attempts to include the value of all California renewable volumes, including non-IOU renewable volumes, in the calculation, which is unnecessary and currently inappropriate. Second, while the PD adopts the proposal of the Joint Parties for valuing the 68% of the California renewables market consisting of IOU procurement, the PD adopts use of a United States Department of Energy ("DOE") survey of reported contact premiums for renewable energy in the Western United States (the "DOE premium") to value the 32% of the California market consisting of procurement by non-IOU retail sellers (Energy Service Providers ("ESPs"), Community Choice Aggregators ("CCAs"), and Publicly Owned Utilities ("POUs").

The PD errs in including non-IOU volumes in the calculation. With the passage of Senate Bill ("SB") 2 1X, there is now a legislative mandate for all retail sellers in California to steadily increase the level of RPS compliant renewables in their portfolio from current levels to 33% by 2020.[4] Thus, during the next nine years, the IOUs will be required to add renewable resources to their portfolios. In this context, the departure of load has the effect of reducing the need for additional procurement to meet the growing RPS requirement.[5] And provided that they meet certain requirements, IOUs can also bank excess RPS-eligible renewables from one year for credit in a future year, thus avoiding the need for a subsequent procurement.[6] In this context, the value to bundled customers from the departure of load is a reduction in the need for subsequent purchases <u>by the IOU</u>. Thus, the cost of procurement for non-IOU entities is not relevant and is not needed to measure bundled customer indifference.

The best information available to estimate the value of this avoided IOU procurement – and therefore the market value of the existing portfolio – is what it paid for recent procurement,

[4] SB 2 1X, Section 20, adding Section 399.15(b) to the Public Utilities Code.
[5] Exh. 800 at 11 (CLECA/CMTA: Dr. Barkovich); Exh. 101 at 10: 20-23 (Joint Parties: Dalessi, Fulmer, Meal).
[6] RT at 54:10-11 (Joint Parties: Fulmer); SB 2 1X, Section 16, adding Section 399.13(a)(4)(B) to the Public Utilities Code.

precisely the data that the Joint Parties' methodology uses to value wholesale renewable generation. If in fact, POUs, ESPs and CCAs pay less (or more) for renewable energy than the IOUs, then using non-IOU renewable procurement data to value excess renewables in an IOU's portfolio would underpay (or overpay) departing load customers for the value of that generation, because the value of the excess to bundled customers is in fact, what IOUs typically pay, and, in turn, what the utilities avoid paying as the result of departure of the load.[7]

The PD erroneously adopts use of the DOE premium to solve two related problems that are not relevant until 2020. First, the PD expresses the concern that the Joint Parties' methodology only accurately values the large proportion of the market comprised of the IOUs, 68%, and fails to account for the remaining 32% of the market comprised of ESPs, CCAs, and POUs.[8] Further, the PD posits that including data from ESPs and CCAs could be expected to lower the market value for renewables because the IOUs are subject to restrictions on contracting that do not apply to ESPs and CCAs.[9] However, the PD adopts an unjustified metric to value renewables in the IOUs' portfolio to solve problems that do not currently exist. Once the 33% RPS goal is achieved at the end of 2020, the statewide market price of RPS-compliant generation would be more relevant for purposes of valuing the RPS renewables in an IOUs' portfolio. By then however, nine years after the passage of SB 2 1X, transparent and reliable indices will likely have developed for the three categories of RPS compliant products created in SB 2 1X.

The PD errs in adopting the DOE premium because this metric does not measure the value of wholesale California-RPS compliant renewable generation. The PD itself acknowledges that there are problems with the DOE premium as follows: "[w]e recognize that questions and

[7] It is worth noting that ESPs and CCAs comprise only a small portion of the market; the bulk of the 32% non-IOU generation market is actually comprised of POU volumes. There is no data in the record on the prices paid by POUs for RPS-compliant renewable resources and whether such prices are above or below typical IOU prices. Moreover, with the passage of SB 2 1X, POUs are now subject to similar RPS requirements as other retail sellers, a factor that will be reflected in the prices of POU RPS renewables procurement.
[8] PD at 18.
[9] Id.

concerns have been raised regarding the usefulness of the DOE data sources as representative of the California market. We conclude, however, that these concerns go to the weight that should be accorded to the data sources."[10] However, the key problem with the DOE premium data for purposes of valuing the renewable resources in the IOUs' portfolios is that it does not even purport to measure the value that is at issue: the wholesale market premium for renewable generation compared to non-renewable generation.[11]

Rather, the DOE premium reflects the average premium for a sampling of voluntary utility green retail pricing programs.[12] As the PD itself points out, the DOE data refers to a different product, and is well below the value of California RPS renewables.[13] Moreover, as DRA witness Ouyang pointed out, there is insufficient information to determine how much revenue is generated by the voluntary green pricing premiums and how much additional RPS resources are procured as a result and hence to determine the price for each unit of renewable energy that is purchased.[14] Thus, the problem is not only that the DOE premium is an unreliable metric (although this is also a problem with the data),[15] but rather that the DOE premium measures something other than what needs to be measured in this case. While the Joint Parties appreciate the need to be pragmatic in the face of imperfect information, the PD errs in using a measurement of premiums paid by retail customers for voluntary renewable premium programs that have no relationship to any particular volume of generation nor any RPS eligibility standards as a measure of the value of specific volumes of wholesale renewable generation procured for compliance with a mandatory program in California. This error is compounded by the fact that

[10] PD at 22.
[11] Exh. 801 at 4 (CLECA/CMTA: Dr. Barkovich; see also exh. 101 at 2-3 (Joint Parties: Dalessi, Fulmer, Meal).
[12] Exh. 300 at 26: 16-18 (SCE:Schichtl); Exh. 100 at 27 (Joint Parties: Dalessi, Fulmer, Meal).
[13] PD at 21.
[14] RT 710:21-28 and 712:1-9 (DRA: Ouyang).
[15] For example, as Joint Party witnesses testified, it is not clear that the database is even current or updated on any regular basis. Although it was reported to have been updated in August 2010, no new programs were listed for 2010, one new program was listed for 2009, and nine new programs were listed for 2008. Exh. 101 at 3:1-6 (Joint Parties: : Dalessi, Fulmer, Meal).

the DOE premium systematically and significantly understates the value of wholesale renewable generation in California.[16]

III. Comments on PD Rulings on All other PCIA Issues

In this section, the Joint Parties identify further errors and clarifications needed in the PD as to each of the other elements of the PCIA calculations for which Joint Parties had suggested specific reforms.

A. Revised Capacity Adder for the MPB

The PD declines to make any changes to the current Resource Adequacy ("RA") capacity adder, and instead leaves in place the RA capacity adders that were adopted four years ago, in Decision 07-01-030: $7/MWH for SCE and SG&E, and $4/MWH for PG&E. The PD agrees that it is reasonable to provide a means of updating the RA capacity value included in the MPB over time as more updated data becomes available,[17] and notes that current capacity values used in the MPB are based on the annualized cost of a combined cycle combustion turbine.[18] However, despite general agreement that the capacity adders should be updated regularly, the PD declines to make changes to the capacity adder for two reasons. First, the PD notes that the Commission has already rejected the idea that $55/kw-year, the figure proposed for the Capacity Procurement Mechanism ("CPM") by the California Independent System Operator ("CAISO"), as an appropriate proxy for RA capacity. Second, the PD notes that there were no other alternatives offered for updating the capacity values other than CPM.[19] On this second point, the PD is incorrect. SCE had recommended that the going-forward costs of a combustion turbine calculated by the California Energy Commission ("CEC") bi-annually as part of its generation

[16] Exh. 101 at 3: 10-30 and 4: 1-8 (Joint Parties: : Dalessi, Fulmer, Meal).
[17] PD at 26.
[18] PD at 24.
[19] PD at 28.

cost study should be utilitized to calculate the RA capacity adder.[20] This recommendation is a practical solution that would allow the capacity adder to be updated based on the latest information available on the going-forward costs of a combustion turbine, developed by an independent entity, the CEC.[21] The PD errs in concluding there is no alternative to maintaining outdated capacity values, and should be corrected to adopt the solution proposed by SCE.[22]

B. CAISO Load-Based Costs

The PD correctly notes that there was wide consensus to eliminate the CAISO load-based costs from the MPB, and therefore adopts that modification. The Joint Parties recommend one clarification to the PD that was agreed to by the bulk of the parties relating to congestion charges. The IOUs all agreed with the Joint Parties that any load-based congestion charges, already are, or should be, excluded from the Total Portfolio Costs, like all other CAISO load based charges.[23] The Joint Parties noted in their Reply Brief that with this clarification, there would be no need for an adjustment to the MPB to address congestion.

C. The MPB Should Reflect the Shape of the Bundled Load Profile

The PD correctly recognizes that the current MPB methodology fails to accurately factor in the value of the shape of the IOUs' supply portfolios. However, the PD should be clarified to use historical bundled load profiles to incorporate the shaping value of the supply portfolio.

The PD states that:

> In order to promote transparency, we shall direct that historical generation data be used, as suggested by SCE. The use of historical data will avoid the need to use confidential data, and will still promote reasonable accuracy. The use of such data will promote consistency with the load profile reflected in the total portfolio.[24]

[20] RT at 125: 4-28, and 126: 1 (SCE: Schichtl)..
[21] 134 FERC ¶ 61,211 (March 17, 2011) at 20.
[22] The result would be some number less than $55 since it would not include the 10% adder used to calculate the CPM.
[23] RT at 85: 17-26 (SCE: Schichtl); RT at 359: 18-21 (PG&E: Barry); RT at 703: 11-19 (SDG&E: Choi)
[24] PD at 33.

The Joint Parties would not object to use of the IOU generation profile to adjust the MPB because as the PD notes, there was little practical difference between that approach, and the load profile approach suggested by the Joint Parties. However, the PD also says:

> Because SCE already makes historical bundled load profiles by rate group publicly available, as do the other IOUs, no additional calculations should be required for purposes of the MPB.[25]

This statement suggests that the PD intends that the IOUs should use historical load profile data, because it is the data that is transparent and publicly available. This was in fact SCE's proposal,[26] which the Joint Parties support because of its transparency and practically. The PD errs to the extent it suggests that the generation profile is publicly available. The one difficulty with using the generation profile is that it is not public.[27] In fact, contrary to what is suggested in the PD, SDG&E witness Choi testified that even the Energy Division does not regularly examine the IOUs' economic dispatch model that would be the source of the generation profile, nor does it monitor the raw inputs to the model.[28] Therefore, the Joint Parties respectfully request that the PD be clarified to direct the IOUs to use historical load profile data so that there is no confusion in this regard.

D. Adjustment to Account for Congestion

The Joint Parties agree with the PD's ruling that:

> . . . there is no need to make a separate adjustment for congestion costs since we have already required the exclusion of CAISO load-related costs from the total portfolio calculation which includes congestion costs.[29]

In fact, the Joint Parties acknowledged this in their Reply Brief.[30]

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[25] PD at 33.
[26] See SCE Opening Brief at 13; Exh. 301 at 7: 7-15 (SCE: Schichtl); Joint Parties Reply Brief at 20.
[27] See Exh. 506 answer to question 5.c (SDG&E: Choi).
[28] RT at 701: 25-28 and 702: 1-16 (SDG&E: Choi).
[29] PD at 35.
[30] Joint Parties Reply Brief at 24.

E. Exclusion of Short-Term Purchases from the Total Portfolio Cost.

The PD does not address the exclusion of short-term purchases from the Total Portfolio Cost, even though the issue was addressed during the proceeding. This may be because there was general consensus by all parties addressing the matter that short term purchases: those under one year should be excluded from the Total Portfolio Costs.[31] Thus, the parties spent relatively little time on the issue. Even though the matter is not contested, the matter was addressed, and the Joint Parties request that this matter be added to the final decision.

F. Setting a Zero Default PCIA Value

The Joint Parties concur with the PD's ruling that rejects PG&E's proposal to set a zero default PCIA value, on the grounds that it would violate the bundled customer indifference principle.

IV. The PD Must Be Modified to Conform Implementation to the Commission Ruling issued on April 14, 2011, as amended on April 22, 2011.

The PD states that:

> We shall implement the changes in methodologies adopted in this decision in accordance with the procedure set forth in the Administrative Law Judge (ALJ) April 14, 2011 Ruling. In accordance with Pub. Util. Code § 310, the directives of the April 14, 2011 Ruling are hereby affirmed by the Commission. Pursuant to the ALJ ruling, the IOUs' previously adopted 2011 PCIA rates were made subject to true-up once the IOUs calculate and implement revised 2011 PCIA rates determined in accordance with the revised methodologies adopted in this proceeding. The effective date of the true-up for SCE and SDG&E was to be the date their 2011 ERRA rates become effective. For PG&E, the effective date was to be the date of the April 14, 2001 Ruling.[32]

It is important to note that the April 14, 2011 Ruling[33] was further clarified by an April 22, 2011 Ruling, which provides, in part, as follows:

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[31] Exh. 300 at 29: 16-18 (SCE: Schichtl); Exh. 401 at 22: 6-12 (PG&E: Barry); Exh. 501 at CF-6: 6-7 (SDG&E: Fang); Exh. 601 at 3:28-19 and 4: 1-2 (DRA, Ouyang).
[32] PD at 91.
[33] Administrative Law Judge's Ruling Regarding Motion Of Joint Parties.

> Once a Phase III decision in this proceeding is issued, SCE understands that it is to calculate what the 2011 PCIA would have been under the Phase III decision between the effective date of the 2011 PCIA unde r the ERRA decisions and the effective date of the Phase III decision, and to refund any difference to Direct Access customers....This ruling affirms that SCE correctly describes the manner in which the April 14 ruling is to be implemented by SCE and SDG&E.[34]

However, the PD is somewhat unclear as to the mechanism to be used to reimburse Departed Load customers for the "difference attributable to the revised PCIA compared with the PCIA previously adopted in their 2011 ERRA proceedings."[35] This is because certain wording in the PD suggests that the change is to be implemented prospectively rather than providing for the refund specified in the April 22 Ruling:

> This difference shall be applied to transactions beginning from the effective date of the PCIA rate change adopted in their respective ERRA proceedings for 2011 through the effective date of the revised PCIA implemented pursuant to the revisions adopted in this proceeding. This resulting difference *shall be incorporated into the prospective 2011 PCIA rates* based upon the revised PCIA methodology.[36]

Applying the PCIA change prospectively, rather than providing for refunds to customers creates a number of inequities. For example, (a) customers who overpaid PCIA but return to bundled service are denied their credit; (b) customers who depart utility bundled service in the future, but did not pay the excessive 2011 PCIA will get an undeserved credit; and (c) future PCIA levels will not be true prices and will send the wrong price signal. Therefore, the cited sentence should be modified as follows:

> This difference shall be applied to transactions beginning from the effective date of the PCIA rate change adopted in their respective ERRA proceedings for 2011 through the effective date of the revised PCIA implemented pursuant to the revisions adopted in this proceeding. This resulting difference shall be *<u>refunded to each of the utility's customers who were direct access, community choice aggregation, or non-exempt departing load customers during the period from the effective date of the PCIA rate change adopted in their respective ERRA proceedings for 2011 through the effective date of the revised PCIA implemented</u>*

[34] Administrative Law Judge's Ruling Amending Prior Ruling, at pp. 1-2.
[35] PD at 92.
[36] PD at 92, emphasis added.

pursuant to the revisions adopted in this proceeding. Future changes to the PCIA shall be incorporated into the prospective 2011 PCIA rates based upon the revised PCIA methodology.

The PD provides that: "For PG&E, any difference between the existing 2011 PCIA rate versus the rate that would result from the revised methodology to be adopted through this proceeding was to be calculated in a deferred account. The resulting adjustment shall be passed through as a PCIA rate adjustment upon the adoption of a revised PCIA methodology in this proceeding."[37] The Joint Parties recommend that the "rate adjustment" referred to in the PD be modified to specify a "rate adjustment in the form of a refund to those customers who were direct access, community choice aggregation or non-exempt departing load customers during the period from April 14, 2011 through the effective date of the revised PCIA implemented pursuant to the revisions adopted in this proceeding…"

V. Conclusion

The Joint Parties respectfully request that the errors in the PD described in these comments be corrected as set forth herein.

Respectfully submitted,

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September 12, 2011

[37] PD at 92.

APPENDIX A:
PROPOSED CHANGES TO THE FINDINGS OF FACT AND CONCLUSIONS OF LAW

Findings of Fact

1. The existing Commission-adopted methodology used to calculate the Indifference Amount has become outdated in view of industry and regulatory changes over time.

2. Pursuant to Pub. Util. Code § 365.1(b), individual retail nonresidential end-use customers may acquire electric service from other providers in each electrical corporation's distribution service territory, up to a maximum allowable total annual limits established in D.10-03-022.

3. Under current rules, former DA customers on bundled utility service must provide six months' notice in order to leave bundled utility service. The six-month notice requirement applies for customers that switch back to DA. A DA customer who returns to bundled service must commit to stay for at least a three-year period.

4. SB 695 requires that other providers of electricity in California are to be subject to the same procurement-related requirements that apply to the IOUs, including RA requirements, renewable portfolio standards, and greenhouse gas emission reductions.

5. The current indifference methodology only recognizes the IOUs' cost of renewable resources in the calculation of the Total Portfolio Cost, but does not account for the market value of <u>the IOUs'</u> renewable resources in the MPB.

6. An adjustment to the MPB to account for the market value of <u>the IOUs'</u> renewable resources will result in a more accurate measure of indifference costs.

New: <u>The methodology proposed by the Joint Parties adequately values the renewable resources in the IOUs' bundled portfolio.</u>

New: Until the RPS target level of 33% is achieved by the IOUs, the value of any excess renewables in an IOU's portfolio due to Departing Load is to reduce the amount of RPS compliant resources that the IOUs will subsequently need to procure.

7. After the IOUs achieve the 33% RPS standard, required by statute by December 31, 2020, an accurate market-based measure for use in a renewable resource adder more appropriately calls for data sources that represent transactions among all load serving entities in California, not just those of the IOUs. After December 31, 2020, when the RPS target level of 33% must be achieved, transparent indices of recent RPS transactions will likely be available.

8. After the statutory 33% RPS standard is met by the IOUs, such that departing load no longer defers or avoids additional RPS procurement, relying solely upon IOU transactions as the data source to construct a renewables adder will be ~~is~~ deficient to the extent it fails to account for transactions of other categories of California load serving entities.

9. ~~All of the parties proposals for adjusting the MPB to account for renewable resources have deficiencies that make the proposals unsuitable as a basis for calculating the indifference amount.~~

10. ~~While the value of the utilities' renewable resources constitute 68% of total California load subject to RPS requirements, the remaining 32% of such resources come from other load serving entities.~~

11. The data on renewable resource transactions from SNL Publications is not a reliable source for purposes of calculating a renewable adder to determine indifference costs.

12. The data reported by the United States Department of Energy survey of reported renewable energy contract premiums in the Western United States compiled by the National Renewable Energy Laboratory is not a relevant or reliable source for purposes of valuing wholesale RPS-

compliant generation in California ~~offers a proxy value that can be used in conjunction with California utility data to produce a weighted RPS adder~~.

New: Because the IOUs claim RPS compliance credit for pre-2004 renewable resources in their portfolio, and the requirement to procure additional RPS-compliant resources is reduced one for one for every MWH of pre-2004 renewable resources generated in the IOU portfolio, the IOUs and their bundled customers benefit from pre-2004 renewable resources.

13. The MPB incorporates a capacity adder value to reflect the cost of resource adequacy based on the annualized cost of a combined cycle combustion turbine, but the current methodology does not provide for updating the value over time.

14. SCE's proposal to update the capacity adder using the California Energy Commission's estimates of the going forward costs of a combustion turbine, which is updated biannually, and the Net Qualifying Capacity" of all generation resources (utility owned and power purchases) in the utility portfolio, is a practical approach to update the RA capacity value in the MPB. ~~The record is insufficient at this time to provide a factual basis to adopt an updated RA capacity adder value for purposes of the MPB. The existing RA capacity adders adopted in D.07-01-030 remain the best RA measure.~~

15. The currently pending CEC proposed "Capacity Procurement Mechanism" price before the Federal Energy Regulatory Commission is not suitable as MPB capacity adder value, particularly because the CPM price is above current RA capacity market values. The FERC has raised questions about the CPM price and has made it subject to refund pending further study.

16. The total portfolio calculation currently includes certain CAISO load-based costs which the IOUs avoid when load departs for DA service. Exclusion of the load-based CAISO costs,

including load-based congestion costs, that vary based on the amount of load will produce a more accurate indifference amount calculation.

17. Under the current method for calculating the indifference amount, the total portfolio reflects the profile of the underlying IOU generation resources or contracts; however, the MPB calculation essentially is weighted based on the number of peak and off-peak hours in a year.

18. The current MPB is based on an implicit assumption that the IOU supply portfolio serves a flatter load profile than it actually does, thus creating an artificially low market value and artificially high indifference amount.

19. Parties identified two alternative approaches by which to revise the MPB to reflect more accurately the shaped~~ing~~ profile of portfolio resources, weighted either by using the IOU generation profile or the IOU bundled load profile.

20. The IOU generation profile would more closely track actual portfolio costs, but the IOU load profile follows the shape of how load varies from hour to hour.

21. By using the utility's bundled load profile for the weighting factors, the shaped energy price for "brown" power would be the same for all PCIA vintages and for the CTC portfolio.

22. The IOUs historical bundled load profile by rate groups is publicly available and adequately reflects the shape of the IOU generation portfolios. ~~inputs for calculating the shaped energy price should be readily available since each utility's bundled hourly load profile is used to derive the utility's fuel and purchase power expense forecast presented in annual ERRA proceedings~~

New. Short-term purchases, for less than one year, should be excluded from total portfolio costs.

23. Bundled customer indifference is determined with reference to total portfolio costs, not isolated costs related to just the ERRA costs.

24. PG&E's proposal would violate the bundled customer indifference by recognizing only the cost to bundled customers from using more above-market CTC resources, while not recognizing the offsetting benefit accruing to bundled customers from also using more below-market utility resources.

25. An 18-month minimum stay requirement for bundled service strikes a reasonable balance, mitigating the risk of stranded RA and other potential stranded costs, while acknowledging that the capped DA market supports some lowering of the minimum stay requirement from its current length of three years.

26. The re-entry fees which are covered under the provisions of § 394.25(e) include all incremental costs resulting from the involuntary return of DA customers to bundled service, including administrative costs and procurement costs that exceed the costs paid by bundled customers.

27. A security bond, letter of credit, or secured cash deposits are alternative means that can meet the ESP financial security obligations of § 394.25(e). The use of self insurance or showing of an ESP's investment-grade bond ratings are inadequate alternatives that fail to provide the requisite financial security required by § 394.25(e).

28. The fees that are currently in effect by utility tariff to cover administrative costs for the voluntary return of a CCA customer offer a reasonable proxy to use for purposes of securing a bond and calculating re-entry fees for involuntarily returned DA customers.

29. A one-year period offers a reasonable time frame for calculating the duration of re-entry fees, in terms of keeping the bond costs manageable while protecting bundled customers against cost shifting.

30. A forecast of incremental procurement costs based on a 95% confidence interval offers a reasonable proxy for achieving bundled customer indifference since this confidence interval was adopted by the Commission in D.07-12-05 as the confidence interval to be used by IOUs to manage rate level risk for bundled service customers.

31. The determination of re-entry fees required under § 394.25(e) requires a forecast of incremental costs for purposes of securing a bond and calculating actual costs of re-entry once an involuntary return occurs.

32. Whether or not the returning DA customer pays the TBS rate or the BPS rate, the incremental costs incurred by the IOU to serve involuntarily returned DA customers would not change. The ESP remains responsible for covering incremental procurement costs.

33. The calculation of estimated re-entry fees as set forth in Appendix A incorporates the substance of the proposed bond methodology of SCE and PG&E and provides a reasonable methodology for use in determining a bond amount under § 394.25(e), subject to further Commission determination of the historical data necessary to calculate the volatility factor.

34. The proposed re-entry fee formula for forecasting procurement costs would use implied volatility data from a third-party broker. Information is available to parties to access market prices and volatilities, although access to the information requires a fee-based subscription. Such data is available for SP 15 based on a proprietary model, but is not available for NP 15.

35. PG&E has not performed a study of volatilities comparing NP 15 and SP 15. Thus, we have no basis for concluding that SP 15 volatilities would serve as a reasonable proxy for NP 15 volatilities or whether SP 15 volatilities could be adjusted to become a reliable proxy.

36. Historic NP 15 data offers an acceptable proxy for calculating NP 15 volatility factors, but a further record is needed to determine the appropriate historical data period to utilize.

37. The calculation of actual re-entry fees set forth in Appendix B incorporates the substance of the proposal of PG&E and SCE and provides a reasonable methodology for determining actual re-entry fees due to an involuntary DA return, subject to determination of the appropriate historical data to use calculate volatility.

38. An ESP with investment grade credit should be able to obtain a bond or insurance policy on the commercial market at an annual cost of about 1% of the face value of the bond/policy amount.

39. The procedures for the filing of advice letters to implement the provisions of the ESP bond requirements proposed by PG&E and SCE are reasonable.

40. The implementation of true-up procedures in accordance with the ALJ ruling dated April 14, 2011, as amended by the ALJ ruling dated April 22, 2011, provides a reasonable means of incorporating the revisions in methodologies adopted in this proceeding into the PCIA and TBS rates for 2011, taking into account the effects of those revisions for periods of time prior to the effective date of this decision.

Conclusions of Law

1. In administering the DA program, any adopted rules are subject to the provisions of Pub. Util. Code § 366.1(d) that all retail customers bear their fair share of purchase power obligations with no shifting of recoverable costs between customers.

2. Consistent with the increased allowances for DA transactions authorized pursuant to SB 695, any revised rules adopted for administering the DA program should also seek to preserve the benefits of customer choice.

3. The total portfolio methodology used to determine bundled ratepayer indifference should be calculated in a manner that subtracts the cost of an IOU's total portfolio from a market price

benchmark that includes recognition of the market value of RPS and RA resources ~~applicable to all load-serving entities~~, including pre-2004 renewable resources in the IOUs portfolios.

4. ~~Since the existing proposals do not offer a suitable basis to determine a market-based adder for RPS resources, t~~The Commission needs to determine a suitable proxy for the market value of RPS and RA resources based upon available information.

5. SCE's proposal for updating the ~~Given the lack of a suitable record regarding an updated~~ resource adequacy capacity adder using the CEC's most recent estimates of the going forward costs of a combustion turbine and the Net Qualifying Capacity of all generation resources (utility owned and power purchases) in the utility portfolio should be adopted~~, the existing capacity adder should continue to be used for the present time~~.

6. All load-related CAISO costs, including load-based congestion costs, should be excluded from the calculation of the total portfolio and market price benchmark in order to produce a more accurate measure of indifference.

7. The determination of the MPB should be revised to more accurately reflect the bundled load shape based upon time-of-use variations.

New: The total portfolio costs should exclude short term purchases under one year.

8. Under Pub. Util. Code § 394.25(e), the ESP is responsible for procuring a bond or related evidence of insurance as delineated in this decision to cover all re-entry fees imposed due to the ESP's customers that are involuntarily returned to bundled service. The ESP shall not be obligated for any re-entry fees, however, if a DA customer returns to the IOU due to default in payment to the ESP or other contractual obligations, or because the DA customer's contract with the ESP has expired.

9. For purposes of assessing re-entry fees, an involuntary return of a DA customer to bundled service may occur due to any of the following:

a. The Commission revokes the ESP registration;

b. The ESP Agreement with the utility becomes terminated; and

c. The ESP or its authorized CAISO SC has defaulted on its obligations, such that the ESP no longer has an authorized SC.

10. If an ESP becomes insolvent and is unable to discharge its obligations to pay re-entry fees, the returning DA customers must bear responsibility for the payment of the re-entry fees.

11. The purpose of § 394.25(e) is to protect against costs being shifted on to other customers in the event of an involuntary return of DA customers to IOU service.

12. The requirements of § 394.25(e) must be satisfied through posting of a bond, letters of credit, or cash security deposits, or equivalent evidence of insurance as delineated in this decision sufficient to cover re-entry fees as defined in this order.

13. The re-entry fees as required under § 394.25(e) resulting from an en masse involuntary return of an ESP's customers to bundled utility service must include all incremental costs incurred by the IOU as a result of the DA customers' involuntary return necessary to avoid cost shifting to bundled customers.

14. Even if involuntarily returned DA customers are charged a portion of the incremental procurement costs through a TBS rate, any such charges imposed on involuntarily returned customers ultimately remain a legal obligation of the ESP pursuant to § 394.25(e).

15. Because incremental procurement costs resulting from serving involuntarily returned DA customers shifting costs must not be shifted to bundled customers, those associated incremental

costs are included in re-entry fees pursuant to § 394.25(e) irrespective of whether the costs are recovered through a TBS rate or not.

16. Because the ESP bond proposal sponsored by PG&E and SCE is not offered as a settlement in this proceeding, the proposal must be evaluated on its substantive merits rather than based upon the Commission's settlement rules.

Nothing in this decision should be construed as a prejudgment regarding the merits of re-entry fees or bond obligations that may be deemed applicable to CCAs.

17. The ESP bond proposal of PG&E and SCE offers a reasonable means of complying with the requirements of § 394.25(e) for determination of an ESP bond obligation, subject to finalizing the derivation of the volatility factor.

18. The steps involved in the calculation of the ESP bond amount for estimated re-entry fees as set forth in Appendix A of this order should be adopted.

19. The steps involved in the calculation of actual re-entry fees to be paid at the time of an involuntary DA customer return as set forth in Appendix B should be adopted.

20. The procedures for implementation of the revised methodologies for calculating the PCIA and TBS rates as adopted in this proceeding should be implemented by advice letter filings in accordance with the directives set forth in the ALJ Ruling issued in this proceeding on April 14, 2011<u>, as amended by the ALJ ruling dated April 22, 2011</u>. The Commission affirms <u>both of </u>the ALJ Ruling<u>s</u> pursuant to the provisions of Pub. Util. Code § 310.

21. Unless otherwise expressly approved in the ordering paragraphs below, any proposals for revisions in the methodologies for calculating the indifference amount or TBS rate should be deemed denied.

Ordering Paragraphs

1. The calculation of the Power Charge Indifference Amount and the Competition Transition Charge applicable to Direct Access, Community Choice Aggregation and other non-exempt Departing Load customers must be modified to incorporate revisions in the calculation of the total portfolio and market price benchmark as directed in the following ordering paragraphs.

2. The Market Price Benchmark used to calculate the indifference amount, PCIA and CTC must be revised to incorporate an adder to reflect the market value of renewable portfolio standard resources.

3. All pre-2004 procurement resources must be included in the Renewable Portfolio Standard calculation for purposes of the Market Price Benchmark used in the ~~indifference~~ calculation of indifference amounts, PCIA and CTC.

4. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company must each file a Tier 2 advice letter with the Energy Division within 30 calendar days following the issuance of this decision, identifying the:

   ~~a. most recent 12 months figures derived from US Department of Energy survey of Western US renewable energy premiums in calculating a weighted proxy for the Market Price Benchmark compiled by the National Renewable Energy Laboratory; and~~

   ~~b.~~ forecasted costs and volumes for 2011 for all Renewable Portfolio Standard – compliant resources that began delivery in year 2010 and those projected in the investor-owned utilities' Energy Resource Recovery Account forecast applications that were to begin delivery in 2011. This must include both contracts and IOU-owned resources. Confidential cost data submitted to Energy Division will be protected from disclosure.

New:

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company must each file a Tier 2 advice letter with the Energy Division annually, starting in 2011, by November 1 of each year , identifying the:

> forecasted costs and volumes for the subsequent calendar year (starting with 2012) of all Renewable Portfolio Standard–compliant resources that began delivery in the current calendar year (starting with 2011) and those projected in the investor-owned utilities' Energy Resource Recovery Account forecast applications that were to begin delivery in the subsequent calendar year (starting with 2012). This must include both contracts and IOU-owned resources. Confidential cost data submitted to Energy Division will be protected from disclosure.

5. The Energy Division will prepare a resolution to adopt the Renewable Portfolio Standard ~~adder~~Benchmark for 2011 and subsequent years ~~to be used to determine a Market Price Benchmark proxy value~~ based on ~~consideration and a 32% weighting of the DOE data in relation to a 68% weighting of~~ the investor-owned utility cost data as ~~relevant in~~ described in this decision to reflect the Commission's adoption of an appropriate ~~adder~~adjustment to reflect the value of renewable resources in the calculation of the Market Price Benchmark used to calculate the indifference amount, PCIA and CTC.

6. All California Independent System Operator (CAISO) charges that vary based on the amount of load, including load-based congestion costs, and all short-term purchases under a year in length shall be excluded from the total portfolio cost and the Market Price Benchmark for purposes of calculating indifference amounts, PCIA and CTC.~~the Power Charge Indifference Amount~~. The list of load-related CAISO charges identified in the testimony of the Joint Direct Access parties (Exhibit 100, Exhibit A) is adopted for use in identifying the applicable load-

related charges to be excluded. As the CAISO charges change over time, the IOUs shall file advice letters to update the excluded charges.

7. The Market Price Benchmark (MPB) calculation must be weighted to reflect variations in load shape on a time-of-use basis based upon the investor-owned utility (IOU) ~~generation~~ bundled load profile data. In order to avoid the necessity to use confidential data, the MPB calculation must make use of most recent historic IOU ~~generation~~ bundled load profile data that is publicly available.

8. The capacity adder in the MPB should be updated using the Net Qualifying Capacity of the utility's electric supply portfolio and the most recent CEC estimate of the going forward costs of a combustion turbine as proposed by SCE.

9. The calculation of the temporary bundled service (TBS) rate shall be conformed to be consistent with the relevant changes in the methodology for calculating the total portfolio and Market Price Benchmark (MPB) as adopted in this decision. Specifically, the adopted MPB changes for Renewable Portfolio Standard resources shall be reflected in the TBS rate. Load-related California Independent System Operator charges, however, shall continue to be included in the TBS rate so that all relevant short-term charges are paid by Direct Access customers.

10. The minimum stay commitment for Direct Access customers electing to return to investor-owned utility procurement service shall be reduced from three years to 18 months.

11. The six-month advance notice requirement shall continue in effect for Direct Access (DA) customers to return to investor-owned utility (IOU) service or for bundled customers departing IOU service to be served by an electric service provider.

12. The proposal for bundled customers to be charged to pay Direct Access customers for negative indifference amounts is denied.

13. The proposal is denied to set the Power Charge Indifference Amount to zero in those instances where the indifference amount is less than the ongoing Competition Transition Charge revenue requirement.

13. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each file a Tier 2 Advice Letter within 30 days of this order to amend their tariffs to incorporate the ESP financial security provisions and re-entry fee provisions in Appendix A and B.

14. Upon Commission approval of the above-referenced advice letters to implement the procedures for the posting of financial security in accordance with this decision, each electric service provider offering Direct Access service within California shall be responsible as a condition of registration of posting a bond and/or other equivalent proof of insurance (e.g., letter of credit, cash deposit, third party guarantee) that covers re-entry fees pursuant to § 394.25(e).

15. The electric service provider re-entry fee must incorporate as a proxy for administrative costs, the administrative fees that are included in the respective retail utility tariff for returning Community Choice Aggregator customers.

16. The electric service provider re-entry fee must include all incremental procurement costs prescribed in Appendix A and B as a result of providing service to *en masse* involuntarily returned Direct Access (DA) customers, including any incremental costs that may otherwise be charged to DA customers.

17. The amount of an electric service provider's bond must be calculated twice annually: once in early November and again in early May. Bonds shall be posted by December 31 and June 30, respectively.

18. For an electric service provider that begins service in Month M+2 (where M denotes the month when the investor-owned utility will calculate the bond amount, and is not May or November), the bond calculation must be performed using Month M-1 data, and the bond shall be for the period from the start date through the next semi-annual calculation.

19. The gross bond amount to cover incremental costs, including procurement costs, must be determined pursuant to the steps as set forth in Appendix A of this decision.

20. The actual re-entry fees applicable upon involuntary return of Direct Access customers must be determined as set forth in Appendix B of this decision.

21. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must submit to the Commission's Energy Division in a Tier 2 advice letter filing, calculated in a manner consistent with this decision. The filing shall include an Excel spreadsheet showing the formulas to derive the values on each cell. The filing must set forth supporting rationales regarding the appropriate historical data necessary to measure the volatility factor in the bond formula.

22. After the Commission approves the initial bond calculation methodology by resolution, all subsequent updates in the bond calculations shall be submitted as a Tier 1 advice letter with Excel spreadsheets as specified above to the Energy Division. The filing shall be deemed accepted unless the Energy Division suspends the advice letter during the 30-day review period.

23. The electric service provider (ESP) is responsible for covering all applicable re-entry fees for its customers that are involuntarily returned. Only if, or to the extent, that the ESP is unable to

cover all of the applicable re-entry fees, any unreimbursed fees from the ESP's must be covered by the returned Direct Access customers.

24. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company must each calculate actual re-entry fees due within 60 days of the earlier of the start of the involuntary return, or the receipt of the electric service provider's written notice of involuntary return, using the method described below.

25. Re-entry fees must constitute a binding estimate of the incremental administrative and procurement costs under then-current market conditions to serve the involuntarily returned Direct Access customers for a one-year period.

26. The re-entry fees must be demanded from the electric service provider only after the involuntary return is initiated.

27. The changes in Power Charge Indifference Amount methodologies adopted in this decision shall be implemented in accordance with the procedure set forth in the Administrative Law Judge (ALJ) April 14, 2011 Ruling, as amended by the ALJ ruling dated April 22, 2011. In accordance with Public Utilities Code Section 310, the directives of the April 14, 2011 ALJ ruling and the April 22, 2011 ALJ ruling are hereby affirmed by the Commission

28. To implement of the revised Power Charge Indifference Amount (PCIA) determined pursuant to this proceeding, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company each must promptly adjust its 2011 PCIA rate prospectively to be consistent with the revised PCIA methodology. Each of the advice letter filings shall also calculate the difference between their existing temporary bundled service (TBS) rate and the revised TBS rate calculated in accordance with the directives in this proceeding. The difference shall applied to transactions covering the same period as for the adjustment to the

PCIA rate, and incorporated as an adjustment to the TBS rate charged to Direct Access customers.

29. Southern California Edison Company and San Diego Gas & Electric Company must calculate the difference attributable to the revised Power Charge Indifference Amount (PCIA) compared with the PCIA previously adopted in their 2011 Energy Resource Recovery Account (ERRA) proceedings. This difference shall be applied to transactions beginning from the effective date of the PCIA rate change adopted in their respective ERRA proceedings for 2011 through the effective date of the revised PCIA implemented pursuant to the revisions adopted in this proceeding. This resulting difference shall be <u>refunded to each of the utility's customers who were direct access, community choice aggregation or non-exempt departing load customers during the period from the effective date of the PCIA rate change adopted in their respective ERRA proceedings for 2011 through the effective date of the revised PCIA implemented pursuant to the revisions adopted in this proceeding. Future changes to the PCIA shall be</u> incorporated as an adjustment to the prospective 2011 PCIA rates in the Tier 2 Advice Letter filing based upon the revised PCIA methodology adopted in this proceeding.

30. Once Pacific Gas and Electric Company (PG&E) implements the revised Power Charge Indifference Amount (PCIA) consistent with the methodologies adopted in this proceeding, PG&E shall promptly revise its previously adopted 2011 PCIA rate to incorporate this deferred difference. This difference must be applied to transactions beginning from the effective date of April 14, 2011 Administrative Law Judge Ruling through the effective date of the revised PCIA implemented pursuant to the revisions adopted in this proceeding. This resulting difference shall be <u>in the form of a refund to each of the utility's customers who were direct access, community choice aggregation or non-exempt departing load customers during the period from April 14,</u>

2011 through the effective date of the revised PCIA implemented pursuant to the revisions adopted in this proceeding. Future changes to the PCIA shall be incorporated as an adjustment to the prospective 2011 PCIA rates based upon the revised PCIA methodology adopted in this proceeding.

31. This proceeding is closed.

CERTIFICATE OF SERVICE

I, **KIANA V. DAVIS,** declare that:

I am employed in the City and County of San Francisco, State of California. I am over the age of eighteen years and not a party to the within action. My business address is City Attorney's Office, City Hall, Room 234, 1 Dr. Carlton B. Goodlett Place, San Francisco, CA 94102; telephone (415) 554-4698.

On September 12, 2011, I served: **OPENING COMMENTS OF JOINT PARTIES ON PROPOSED DECISION OF ADMINISTRATIVE LAW JUDGE PULSIFER ON DIRECT ACCESS REFORMS** by electronic mail on the attached Service List, Proceeding No. R. 07-05-025.

The following addressee(s) without an email address were served:

☒ **BY UNITED STATES MAIL**: Following ordinary business practices, I sealed true and correct copies of the above documents in addressed envelope(s) and placed them at my workplace for collection and mailing with the United States Postal Service. I am readily familiar with the practices of the San Francisco City Attorney's Office for collecting and processing mail. In the ordinary course of business, the sealed envelope(s) that I placed for collection would be deposited, postage prepaid, with the United States Postal Service that same day.

Malcolm Reinhardt
Accent Energy
1299 Fourth Street, Suite 302
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I declare under penalty of perjury pursuant to the laws of the State of California that the foregoing is true and correct.

Executed September 12, 2011, at San Francisco, California.

/S/
KIANA V. DAVIS

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