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 THE DIVISION OF RATEPAYER ADVOCATES ON PROPOSED DECISION ADOPTING DIRECT ACCESS REFORMS

KE HAO OUYANG
Regulatory Analyst for
Division of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-1235

CHARLYN HOOK
Attorney for
Division of Ratepayer Advocates
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-3050
Fax: (415) 703-2262
E-mail: chh@cpuc.ca.gov

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I. INTRODUCTION AND SUMMARY

Pursuant to Rule 14.3 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), the Division of Ratepayer Advocates (DRA) offers these opening comments on the August 23, 2011 Proposed Decision (PD) of Administrative Law Judge (ALJ) Thomas R. Pulsifer in the above-captioned proceeding adopting Direct Access (DA) reforms. DRA commends the PD for resolving the Phase III issues in a manner that accurately captures the consensus position of the parties on most issues, and, where parties are divided, strikes a fair balance between the varied interests at stake in this proceeding. For the reasons stated below, DRA supports the PD, with minor modifications discussed herein.

The PD revises the methodology for calculating the market price benchmark (MPB) used to calculate DA customers' cost responsibility necessary to maintain bundled customer indifference; adopts a provision to recognize renewable resource attributes in the MPB; removes load-related California Independent System Operator (CAISO) costs from total portfolio costs; updates load profile calculation to reflect time-of-use load variations; and adopts conforming changes in the transitional bundled service (TBS) rate to be consistent with the changes adopted in the MPB calculation.

The PD also retains the existing six-month advance notice requirements for switching between utility bundled service and DA service; reduces the minimum stay requirement from three years to 18 months for DA customers seeking to return from bundled service back to DA service; maintains existing safe harbor provisions without modification; and adopts provisions to meet the statutory financial security requirements applicable to electric service providers (ESPs) to cover the risk of an en masse involuntary return of ESP customers to bundled service.

DRA supports the PD's findings and conclusions, but has some concerns over the PD's proposed methodology for determining the market value of renewable portfolio standard (RPS) eligible resources. The PD found that all the parties' conflicting proposals suffer from various deficiencies in completeness, relevance, and/or transparency of the data to be used, so none of the parties' proposals are entirely acceptable.[1] Accordingly, the PD attempts to develop a compromise proxy RPS adder. The PD uses the Joint Parties' proposal to determine 68% of the RPS adder, even though the PD acknowledged that the Joint Parties' proposal fails to capture the benefit of long term contracts, overestimates the average cost of front-loaded generation facilities, and could result in double counting of the capacity value of renewable resources.[2] The PD's RPS adder methodology does not correct these deficiencies, and therefore may lead to an overestimation of the value of renewable resources in the total portfolio, an underestimation of DA customers' cost responsibility, and result in cost shifting to bundled customers.

DRA remains committed to developing a transparent and accurate methodology for determining the value of RPS-eligible resources, and supports using a temporary Commission determined proxy price until transparent renewable energy market information becomes available. DRA does not oppose the overall objective of the PD's MPB methodology, but offers an alternative which would correct certain shortcomings in

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[1] PD, pp. 16-17.

[2] PD, pp. 18.

the PD's methodology. DRA's proposed revisions neither undercut nor contradict the PD; but are intended to more accurately capture the market value of RPS-eligible resources. The following is a summary of DRA's recommendations:

- Revise the MPB methodology to account for value of long term contracts, lag time between contract signing and actual delivery, and to prevent double counting the capacity value of renewable resources.
- Adopt the PD's finding that the capacity procurement mechanism (CPM) does not reflect the market price for resource adequacy (RA) capacity or short-term capacity costs, so the existing RA capacity adders for the MPB should remain in place.
- Adopt the PD's finding that all load-related CAISO costs, which include congestion costs, should be removed from the total portfolio, to avoid an additional adjustment for congestion costs.
- Adopt the PD's finding that any change adopted with respect to the power charge indifference adjustment (PCIA) and MPB should be reflected in the TBS rate, including the commodity costs of power, the incremental costs of RPS compliance, and any incremental RA capacity costs.
- Adopt the PD's findings and recommendations on six-month advance notice requirement for switching, minimum stay requirements, and safe-harbor provision.
- Adopt the PD's findings and recommendations on ESP's financial security requirements, re-entry fees, and ESP bond proposal.

II. DISCUSSION

A. Revise renewable portfolio standards adder for market price benchmark to correct deficiencies.

Parties generally agree that the indifference methodology should be revised to reflect the market value of renewable resources in the MPB. However, in the absence of a source for transparent renewable energy market information, parties disagree over what method to use for determining the value of renewable resources. The Joint Parties proposed to use investor-owned utility (IOU) costs for renewable resources that commenced or is projected to commence delivery. Southern California Edison Company (SCE) and San Diego Gas and Electric Company (SDG&E) proposed to use data compiled by the Department of Energy (DOE) National Renewable Energy Laboratory (NREL) reflecting premiums paid by retail energy consumers. Pacific Gas and Electric Company (PG&E) proposed to use publicly available market indices for California Tradable Renewable Energy Credits (TRECs).[3] The PD offers a compromise position. It would be a weighted RPS adder allocating 68% to IOU costs for RPS-eligible resources based on the Joint Parties' proposed methodology and the remaining 32% to DOE data.[4]

DRA commends the Commission for its attempt to develop a benchmark that reflects public prices paid by both buyers and sellers, using recent transactions for delivery of RPS-compliant power in California as a proxy for the market value of RPS-eligible resources.[5] Because transparent renewable energy market information is not currently available, and because parties are reluctant to share confidential contract information due to confidentiality concerns, fashioning a reasonable proxy price has been a challenge. The PD recognizes that all the conflicting proposals are lacking in some respect, i.e. they rely upon a data set that is incompete, partially irrelevant, or lacking in transparency. These flaws make all proposals unsuitable as a basis for calculating the indifference amount.[6] The PD's RPS adder is a marked improvement, and addresses some, but not all, of the deficiencies of the Joint Parties' proposal. DRA therefore supports the PD's RPS adder, with some modifications.

To address the remaining deficiencies, DRA recommends the Commission revise the PD's RPS adder to account for: (1) the value of long term contracts, (2) lag time between contract signing and actual delivery, and (3) to prevent double counting the

[3] PD, pp. 12-13.
[4] PD, pp. 21-22.
[5] PD, p. 16.
[6] PD, pp. 16-17 and finding of fact (FOF) 9, p. 95.

capacity value of renewable resources. DRA's recommendations are discussed in detail below.

1. Use levelized costs to correctly capture average cost of front-loaded generation resources.

The PD declined to adopt the Joint Parties' proposal, in part because the proposal fails to capture the benefit of long-term contracts and overestimates the average cost of front-loaded generation facilities, where prices are higher in early years and lower in later years, because it only applies IOU average RPS resource contract prices from the first two contract years, regardless of contract duration.[7] However, the PD's RPS adder also does not correct this deficiency. DRA argued in testimony that in order to compare apples to apples, the levelized costs of front-loaded generation resources should be compared to the levelized costs of non-front-loaded generation resources.[8] Using levelized costs prevents overestimating the cost of front-loaded generation resources. Since these costs are used to estimate the value of the RPS-eligible resources in the total portfolio, using levelized costs prevents overestimating the value of renewable resources, underestimating the DA cost responsibility, and helps to prevents cost shifting and maintain bundled customer indifference. Therefore, DRA recommends the Commission use levelized costs instead of costs for RPS-eligible resources that began delivery in the current year or are projected to begin delivery in the following year to accurately determine the value of RPS-eligible resources.

Pacific Gas and Electric Company (PG&E) agrees that not using levelized prices for the life of a utility-owned generation resource may result in a skewed benchmark, since utility-owned resources are typically substantially more expensive in the early years of the life of the asset.[9] The Joint Parties' witness, Mr. Fulmer, concurred during cross examination that the cost of a utility owned generation facility can be high in the first

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[7] PD, p. 18.

[8] Exhibit 601, p. 10.

[9] Opening Brief of Pacific Gas and Electric Company (PG&E Opening Brief), May 6, 2011, p. 9.

couple of years and decreases over the life of the project.[10] Mr. Fulmer also acknowledged that the Joint Parties' proposal may result in only the highest price portion of a contract being counted.[11] The Joint Parties argue in briefs that front-loaded projects could be offset by back-loaded power purchase agreements, but did not provide any supporting evidence to show that this offsetting occurred.[12] Since all parties agree that the Joint Parties' proposal may overestimate the costs of front-loaded generation facilities, DRA recommends the Commission revise the PD's RPS-adder to use levelized costs instead of costs for RPS-eligible resources that began delivery in the current year or are projected to begin delivery in the following year to correctly value front-loaded generation resources, and prevent cost shifting to bundled customers.

2. Include prices from all RPS-compliant resources used to serve customers for the applicable year.

The PD found that to accurately reflect the market value of RPS-compliant renewables, the benchmark should reflect current prices paid by buyers and sellers in recent transactions for delivery of RPS-compliant power in California for the forecast year.[13] However, it is not clear the PD accomplishes this goal. The PD's RPS adder relies on information which may include prices from older transactions, due to the lag time between contract signing and actual delivery. In addition, the PD's RPS adder appears to assume that the IOUs' total renewable resources commencing delivery in a particular year represents 68% of total renewable resources commencing delivery in the California RPS market for that same year. To address these deficiencies, DRA recommends that the PD be modified to use prices from all RPS-eligible resources used to serve customers in a particular year to determine the renewable adder, rather than the

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[10] Tr. p. 21, line 21 – p. 22, line 4.
[11] Tr. p. 23, lines 6-25.
[12] Joint Parties' Opening Brief, pp. 14-15.
[13] PD, p. 16.

costs for RPS-eligible resources that began delivery in the current year or are projected to begin delivery in the following year.

Parties generally agree that there is lag time between contract signing and actual delivery, so the PD's methodology may include costs from older transactions, which may not be representative of current renewable energy costs. The Joint Parties acknowledge that under its proposal, some older transactions may be included in the data that are used to calculate the renewable adder, because some resource commitments have long lead times.[14] PG&E also indicated that some IOU contracts may take four to five years to commence operation, so it is entirely possible that the IOU may not have any RPS-eligible resources that started delivery in a particular year.[15] SCE also indicated that renewable resources just beginning delivery in a particular year have usually been contracted for years ago.[16] SDG&E also indicated that contracts for new renewable energy resources are typically entered into years before delivery occurs.[17]

Since the RPS adder is mostly based on information from older transactions, it may be more appropriate to include prices from all RPS-resources used to serve customers in a particular year to provide a larger sample to determine the renewable adder. In addition, the existence of back-loaded power purchase agreements suggest that contracting parties already accounted for the forecast prices of RPS-eligible resources in future delivery years. These contract prices should reflect the parties' best estimate of the price of renewable resources in the future delivery years. Therefore, it is appropriate to include the costs from all RPS-eligible resources used to serve customers in a particular year to derive an accurate proxy for the market value of RPS-eligible resources.

[14] Opening Brief of California State University, Marin Energy Authority, California Municipal Utilities Association, City and County of San Francisco, San Joaquin Valley Power Authority, Alliance for Retail Energy Markets, Direct Access Customer Coalition, Bluestar Energy, Pilot Power Group, Inc., Energy Users Forum and University of California (Joint Parties Opening Brief), May 6, 2011, p. 12.

[15] Reply Brief of Pacific Gas and Electric Company (PG&E Reply Brief), May 27, 2011, pp. 5-6.

[16] Opening Brief of Southern California Edison Company (SCE Opening Brief), May 6, 2011, p. 9.

[17] Opening Brief of San Diego Gas and Electric Company (SDG&E Opening Brief), May 6, 2011, p. 6.

The PD reasoned the IOUs' load represents 68% of total California load subject to the RPS requirement, while ESPs, community choice aggregators (CCAs) and publicly-owned utilities make up the remaining 32% of total California load.[18] Thus, the PD utilizes a 68-32 ratio to weight the propose RPS adder, assuming that the IOUs' renewable resources that commence delivery in a particular year represent 68% of total renewable resources commencing delivery in the California RPS market for the same year.[19] However, there is no evidence in the record suggesting that the IOUs' share of resources commencing delivery in a given year also represent 68% of the total resources commencing delivery in the California market for the same year. On the contrary, the lag time between contract signing and actual delivery suggests that the amount of renewable resources commencing delivery in any particular year may vary significantly. It is even possible that the IOU may not have any new RPS-eligible resources commencing delivery in a particular year,[20] so the proportion may deviate significantly from 68%. Therefore, DRA concludes that while the 68-32 ratio may be appropriate for evaluating the total portfolio, it is not necessarily suitable for evaluating a subset of the total portfolio, such as RPS-eligible resources that began delivery in the current year or are projected to begin delivery in the following year.

Since the Joint Parties' proposal only includes prices from renewable resources that began delivery in the current year or are projected to begin delivery in the following year, which is a subset of all RPS-eligible resources used to serve customers in a particular year, the 68-32 ratio may not be the best weight. DRA recommends that instead of trying to determine a separate weight for each year, the Commission revise the PD's RPS adder to include prices from all RPS-eligible resources used to serve customers in a particular year so the 68-32 ratio can be applied correctly. This will help to ensure

[18] PD, pp. 17-18 and FOF 10, p. 95.

[19] PD, pp. 21-22.

[20] Reply Brief of Pacific Gas and Electric Company (PG&E Reply Brief), May 27, 2011, pp. 5-6.

an accurate value for RPS-eligible resources in the total portfolio and prevent cost shifting.

3. Revise RPS adder proposal to prevent double counting the capacity value of renewable resources.

In addition to the above problem, the PD also found that the Joint Parties' proposal may double count the capacity value of renewable resources, which would overestimate the value of renewable resources, underestimate the DA customers' cost responsibility, and result in cost shifting to bundled customers.[21] In rebuttal testimony, the Joint Parties agreed that there is a potential for double-counting the value of the capacity associated with the renewable power and offered revisions to its proposal.[22] It appears the PD refers to an earlier version of the Joint Parties' proposal that does not include these revisions, and should be updated accordingly.[23] (DRA's Appendix A shows the revisions offered by the Joint Parties to prevent double counting the capacity value of renewable resources.)[24]

DRA offers the following recommended changes to the Joint Parties' revised RPS adder proposal: (1) account for the value of long term contracts, (2) account for lag time between contract signing and actual delivery, and (3) prevent double counting the capacity value of renewable resources. DRA's revisions improve and enhance the PD's RPS adder to more accurately capture the market value of RPS-eligible resources. Therefore, DRA urges the Commission to revise the PD to adopt the following revisions incorporating the revisions of DRA and the Joint Parties to correctly value RPS-eligible resources, and prevent cost shifting to bundled customers. (DRA's recommended changes in bold underline, revised Joint Parties' proposal language in bold italics.)

- Each utility would identify all RPS-compliant resources that ~~began delivery in year 2010 and those projected in their ERRA forecast applications to begin~~

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21 PD, p. 18.

22 Exhibit 101, pp. 11-12.

23 PD, p. 12.

24 Exhibit 101, pp. 11-12.

~~delivery in 2011~~ **<u>are used to serve customers during the current year and those projected to serve customers in the next year.</u>** This would include both contracts and IOU-owned resources.

- The IOUs would identify the projected costs of energy produced by each of these resources ~~in 2011~~. ***The IOUs would also identify the NQC of those resources.***
- IOUs would then provide these data (costs in dollars and volumes in MWh ***and QC in kW***) to the Energy Division.
- The Energy Division would then calculate the average cost of power from these resources ~~in 2011~~ by summing up all the costs from all three IOUs***, subtracting the product of the NQCs of those resources times the ~~CAISO's Interim Capacity Procurement Mechanism (ICPM)~~*** **<u>IOU's respective RA capacity adder ($4/MWh for PG&E, $7/MWh for SCE and SDG&E),</u>** and dividing by the sum of all the MWHs from all three IOUs. This could be calculated or verified by trusted non-market participant(s).

(Changes also set forth in the Appendix A.)

B. Maintain existing resource adequacy capacity adders.

DRA supports the PD's determination to continue using existing RA capacity adders for the MPB.[25] DRA agrees with the PD's finding that the Capacity Procurement Mechanism (CPM) before the Federal Energy Regulatory Commission (FERC) is not a suitable proxy for RA capacity market values.[26] DRA agrees that the CPM was not developed to be a proxy for short-term RA values, but was developed as the price paid to generators to provide a backstop to procure capacity in cases of system deficiencies. The CPM does not reflect the market price for RA capacity or short-term capacity costs. In addition, the FERC has raised questions about the CPM price and has made it subject to refund pending further study. DRA urges the Commission to adopt the PD's findings and continue using existing RA capacity adders for the MPB.

[25] PD, p. 29, FOF 14, p 95, conclusion of law (COL) 5, p. 100.

[26] PD, pp. 26-29 and FOF 15, p. 95.

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C. Remove all load-related CAISO costs from total portfolio.

DRA supports the PD's determination to exclude all load-related CAISO costs from the total portfolio.[27] DRA agrees that load-related CAISO costs are avoided when load departs.[28] DRA also agrees with the PD's finding that a separate adjustment for congestion costs is not necessary since all load-related CAISO costs, including congestion costs, will be excluded from the total portfolio.[29] It appears all parties have reached a consensus on this issue. Therefore, DRA recommends the Commission adopt the PD's findings and order the utilities to exclude all load-related CAISO costs from the total portfolio costs.

D. Update transitional bundled service rates to reflect changes to the PCIA and MPB.

DRA supports the PD's determination to reflect any changes to the PCIA and MPB in the TBS rate to ensure consistency.[30] This includes the commodity costs of power, the incremental costs of RPS compliance, and any incremental capacity/RA costs. All parties agree that the TBS rate is a market-based price to reflect costs that the IOU incurs to serve DA customers that have not provided notification to return to bundled service. Therefore, the TBS rate must be updated to reflect any changes to the PCIA and MPB to prevent cost shifting. Since there is no opposition to this proposal, DRA recommends the Commission adopt the PD's findings and order the utilities to update the TBS rate to reflect any changes to the PCIA and MPB.

[27] PD, p. 30, COL 6, p. 100.
[28] PD, pp. 30-31.
[29] PD, p. 35.
[30] PD, pp. 39-41.

E. Adopt PD's findings on direct access switching rules

1. Reduce minimum stay requirement to 18 months.

DRA agrees with the PD's finding that the minimum stay requirement is necessary to prevent cost shifting to bundled customers.[31] The PD concluded that the SB 695 cap on the DA market provides some mitigation in the risk of stranded costs and supports lowering the minimum stay requirement.[32] However, the PD also found that a one-year period is too short to mitigate the risk of stranded costs, and may not provide the utilities adequate time to adjust their portfolios to reflect shifting load. The PD noted that in addition to addressing the concern with gaming, the Commission also seeks to mitigate the risk of stranded costs from the utilities' prospective procurement obligations by considering the mix of resources and average duration of contractual obligations.[33] The Commission determined that a minimum stay requirement of 18 months will minimize stranded costs associated with intermediate-term procurement.[34] The PD also clarifies that the minimum stay period commences when a returning DA customer begins paying bundled service rates.[35] DRA is not opposed to reducing the minimum stay requirement to 18 months, since this provides the utilities with adequate time to adjust their portfolios to prevent cost shifting to bundled customers. DRA recommends the Commission adopt the PD's findings and reduce the minimum stay requirement to 18 months, commencing when a returning DA customer begins paying bundled service rates.

2. Maintain six-month advance notice requirement to switch service.

DRA supports the PD's determination to maintain the six-month advance notice requirement for customers seeking to return from DA to bundled service.[36] DRA agrees

[31] PD, p. 42 and FOF 25, p. 97.
[32] PD, p. 45.
[33] PD, pp. 46-47.
[34] PD, p. 47.
[35] PD, p. 47.
[36] PD, pp. 50-51.

with the PD's finding that a six-month advance notice is necessary to allow the IOUs to reasonably adjust its portfolio to mitigate the risk of stranded costs when load departs.[37] The six-month advance notice is also necessary to allow the IOUs to reasonably mitigate the sudden swings in bundled service customers' load when customers switch back to bundled service. DRA agrees with the PD's finding that the six-month advance notice requirement to switch service should be maintained, and urges the Commission to adopt the PD's finding without modification.

3. Maintain safe harbor provision without modifications.

DRA supports the PD's determination to maintain existing safe harbor rules without modification, and to continue treating the six-month advance notice period as starting after the 60-day-safe harbor period.[38] DRA agrees with the PD's finding that the IOU is uncertain of whether a DA customer will return to bundled service, unless the customer provides notice before or during the safe harbor period.[39] Therefore, treating the six-month advance notice period as starting concurrently with the 60-day safe harbor period would reduce the notice period from six months to four months, and create undue risk and uncertainty to bundled ratepayers, which may result in cost shifting to bundled customers. DRA recommends the Commission adopt the PD's findings and maintain existing safe harbor rules without modification to avoid cost shifting to bundled customers.

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[37] PD, pp. 50-51.

[38] PD, p. 52.

[39] PD, p. 52, and Post Hearing Brief of the Division of Ratepayer Advocates (DRA Post Hearing Brief), May 6, 2011, pp. 9-10.

F. Adopt PD's finding on ESP financial security requirements.

1. It is necessary for ESPs to post financial security instruments to prevent cost shifting.

DRA agrees with the PD's finding that mass involuntarily returned DA customers are to be protected by the ESP's financial security instrument covering all of the IOU's incremental costs to serve those returned customers.[40] Both DRA and the PD's interpretation of Public Utilities Code § 394.25(e) concluded that the ESP is legally obligated to cover all incremental costs resulting from an involuntary return of its customers to IOU procurement, and the ESP bond must be sufficient to cover all such costs.[41] DRA agrees that the ESP bond is necessary to prevent cost shifting to bundled customers in the event of an involuntary return. DRA recommends the Commission adopt the PD's findings and order all ESPs to meet financial security requirements to prevent cost shifting and maintain bundled customer indifference.

2. Re-entry fees should include all administrative, procurement, and other relevant costs.

DRA supports the PD's finding that re-entry fees include administrative, procurement, and other relevant miscellaneous costs associated with involuntary return of ESP customers to the IOU, to prevent cost shifting to bundled customers.[42] Parties generally agree that the administrative fees imposed by the utility for implementing customer's change of service request should be included in the re-entry fees.[43] DRA believes the administrative fee for a voluntarily return customer is a reasonable proxy for the administrative fee for an involuntarily returned customer. Therefore, DRA is not

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[40] PD, p. 56 and COL 8, p. 100.

[41] PD, p. 56, and Opening Brief of the Division of Ratepayer Advocates Addressing Legal Issues Pertaining to Electric Service Provider Bonding Requirement (DRA Opening Brief on Bond), January 24, 2011, pp. 3-4.

[42] PD, p. 65 and FOF 26, p. 97.

[43] PD, pp. 58-65 and Exhibit 602, p. 14.

opposed to the PD's proposal to establish the administrative fees using the IOU's authorized fee rate for voluntarily returning CCA accounts.[44]

Some parties stated that the TBS rate essentially served the same purpose as a re-entry fee but is not technically a re-entry "fee" for which the bond amount should cover.[45] Thus, all parties agree that either the involuntarily returned customer or the ESP should be responsible for procurement costs, to prevent cost shifting and to maintain bundled customer indifference. Since the PD determined that the ESP is legally obligated to cover all incremental costs resulting from an involuntary return of its customers, procurement costs must be included in the re-entry fees, and be covered by the ESP bond. DRA is not opposed to the PD's proposal to determine the applicable incremental procurement costs based on the SCE/PG&E bond proposal.[46]

DRA agrees with the PD's finding that involuntarily returned DA customer should be placed on the bundled portfolio service (BPS) rate schedule, and not the TBS rate schedule, since Public Utilities Code § 394.25(e) requires the ESP - not the DA customers - to absorb the risks and costs associated with the ESP's default.[47] DRA also agrees that placing involuntarily returned DA customers on the TBS rate, and having bundled service customers share the responsibility for residual re-entry fees after six months improperly allocates the risks of mass involuntary returns to the IOUs and their customers.[48] Public Utilities Code § 394.25(e) requires the ESP to be responsible for all re-entry fees necessary to avoid imposing costs on bundled customers, and to indemnify their customers from costs of an involuntary return. DRA supports the PD's findings on ESP financial security requirements. DRA recommends the Commission adopt the PD's findings and recommendations on ESP's financial security requirements, re-entry fees,

[44] PD, p. 66 and FOF 28, p. 97.
[45] PD, pp. 58-65 and Exhibit 602, p. 14.
[46] PD, p. 66, FOF 33, p. 98 and COL 17, p. 102.
[47] PD, pp. 66-67.
[48] PD, pp. 67-68.

and the ESP bond proposal to prevent cost shifting in the event of an en masse involuntary return.

III. CONCLUSION

DRA commends the PD for accurately capturing the parties' consensus positions and striking a fair balance between the varied interests at stake in this proceeding. DRA supports the PD, with the proposed revisions set forth in these comments which will enhance the PD's RPS adder methodology. DRA urges the Commission to adopt these recommended modifications in the final decision to prevent cost shifting and maintain bundled customer indifference.

Respectfully submitted,

/s/ CHARLYN HOOK

Charlyn Hook

Attorney for the Division of Ratepayer Advocates

California Public Utilities Commission
505 Van Ness Ave.
San Francisco, CA 94102
Phone: (415) 703-3050
Fax: (415) 703-2262
E-mail: chh@cpuc.ca.gov

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APPENDIX A

The following language shows all of DRA's recommended changes to the PD, incorporating both the revised language from the latest Joint Parties' proposal (in bold italics), and DRA's recommendations (bold underlined).

PD at page 12:

- Each utility would identify all RPS-compliant resources that ~~began delivery in year 2010 and those projected in their ERRA forecast applications to begin delivery in 2011~~ **<u>are used to serve customers during the current year and those projected to serve customers in the next year.</u>** This would include both contracts and IOU-owned resources.
- The IOUs would identify the projected costs of energy produced by each of these resources ~~in 2011~~. ***The IOUs would also identify the NQC of those resources.***
- IOUs would then provide these data (costs in dollars and volumes in MWh ***and QC in kW***) to the Energy Division.
- The Energy Division would then calculate the average cost of power from these resources ~~in 2011~~ by summing up all the costs from all three IOUs***, subtracting the product of the NQCs of those resources times the ~~CAISO's Interim Capacity Procurement Mechanism (ICPM)~~*** **<u>IOU's respective RA capacity adder ($4/MWh for PG&E, $7/MWh for SCE and SDG&E),</u>** and dividing by the sum of all the MWHs from all three IOUs. This could be calculated or verified by trusted non-market participant(s).

Original language from the PD at page 12:

- Each utility would identify all RPS-compliant resources that began delivery in year 2010 and those projected in their ERRA forecast applications to begin delivery in 2011. This would include both contracts and IOU-owned resources.
- The IOUs would identify the projected costs of energy produced by each of these resources in 2011.
- IOUs would then provide these data (costs in dollars and volumes in MWh) to the Energy Division.
- The Energy Division would then calculate the average cost of power from these resources in 2011 by summing up all the costs from all three IOUs, and dividing by the sum of all the MWhs from all three IOUs.

Revisions to PD reflecting the Joint Parties' revised proposal as set forth in Exhibit 101, Joint Parties' Rebuttal Testimony at pages 11 to 12:

- Each utility would identify all RPS-compliant resources that began delivery in year 2010 and those projected in their ERRA forecast applications to begin delivery in 2011. This would include both contracts and IOU-owned resources.
- The IOUs would identify the projected costs of energy produced by each of these resources in 2011. ***The IOUs would also identify the NQC of those resources.***
- IOUs would then provide these data (costs in dollars and volumes in MWh ***and QC in kW***) to the Energy Division.
- The Energy Division would then calculate the average cost of power from these resources in 2011 by summing up all the costs from all three IOUs***, subtracting the product of the NQCs of those resources times the CAISO's Interim Capacity Procurement Mechanism (ICPM),*** and dividing by the sum of all the MWHs from all three IOUs. This could be calculated or verified by trusted non-market participant(s).

Minor corrections to the PD:

Page 3, end of second full paragraph: Change "(R.) 03-10-033" to "(R.) 03-10-003."

Page 5, middle of second full paragraph: Change "(R.) 03-10-033" to "(R.) 03-10-003."

Page 78, last paragraph: Change "(R.) 03-10-033" to "(R.) 03-10-003."