BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewable Portfolio Standard Program.	Rulemaking 11-05-005 (Filed May 5, 2011)

THE DIVISION OF RATEPAYER ADVOCATES COMMENTS ON STAFF PROPOSAL FOR A METHODOLOGY TO IMPLEMENT PROCUREMENT EXPENDITURE LIMITATIONS FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM

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I. INTRODUCTION

The Division of Ratepayer Advocates (DRA) respectfully submits the following opening comments and responses to the questions posed in the July 23, 2013, Administrative Law Judge's Ruling Requesting Comments on Staff Proposal for a Methodology to Implement Procurement Expenditure Limitations for the Renewables Portfolio Standard Program (staff proposal or proposal).

The staff proposal seeks to implement Public Utilities Code Section 399.15(c)-(g) requiring the California Public Utilities Commission (Commission) to design and implement a method to calculate and administer procurement expenditures limitations (PEL) for procurement to meet the renewables portfolio standard (RPS). DRA supports the staff proposal and most aspects of the proposed methodology but recommends the following modifications and clarifications:

- To determine if a PEL has been set at a level that will prevent "disproportionate rate impact," the Commission must consider all the costs – including indirect costs – that comprise the rate impact of the RPS program;
- To determine that "disproportionate rate impact" has been avoided, the Commission should establish a rate impact level, measured as a rate increase attributable to renewables, and compare the proposed PEL, including indirect costs, to that level; and
- The investor owned utilities (IOUs or utilities) may voluntarily over-procure renewables as long as those resources are procured within a competitive all-source process. Expenditures associated with voluntarily over-procured renewables need not be tracked within the PEL as long as the utility will not use the renewable energy credits (RECs) generated by those facilities toward RPS obligations.

II. DISCUSSION

A. The PEL Should Continue in Perpetuity Alongside the RPS Requirement and Remain Even Once a Utility Has Reached 33% RPS (Questions 1 and 4)

The PEL should extend beyond 2020 because Section 399.15(e) requires all retail sellers of electricity to procure not less than 33 percent by December 31, 2020, and continue to procure not less than 33 percent of retail sales in all subsequent years.[1] Thus, unless the statute is amended, the 33 percent requirement will continue in perpetuity. And so should the PEL methodology.

Further, even if a utility has reached 33 percent RPS, the PEL should continue. The purpose of the PEL is to track and limit RPS expenditures regardless of the year in which the expenditures occur and regardless of the utility's procurement levels in that year.

B. The Proposed Rolling Ten-Year Timeframe is Reasonable and Consistent With the LTPP (Questions 2 and 3)

Staff's proposed ten-year time frame for the PEL balances realistic forecasts with ten year planning to allow the utilities and Commission to modify procurement behavior before a utility goes over its PEL. A rolling ten year timeframe helps the Commission and the utilities make considered cost containment decisions in a market with long contracting and development timelines.

In addition, the rolling ten year time frame that is re-set every two years is similar to Long Term Procurement Planning (LTPP). LTPP is an umbrella resource planning process that accounts for all resources, including renewables, over a ten-year horizon. Using the rolling ten-year timeframe will make the PEL and LTPP methodologies consistent, simplify the administrative process, and allow for resource planning and RPS cost forecasts to survey similar time frames.

C. All Direct Renewable Utility-Owned Generation (UOG) Costs Must Count Toward the PEL Which Will Assure That Power Purchase Agreements (PPAs) and UOG Are Treated Equally Under the PEL (Questions 5 and 7)

All direct IOU costs associated with RPS-eligible UOG should be treated like the costs of a PPA within the PEL framework. These costs, whether ratebased or directly passed through to ratepayers, comprise the annual revenue requirement of a UOG facility and that total should be accounted for in the PEL, much like the expenditures associated

[1] California Public Utilities Code section 399.11-399.32.

with a renewable PPA. This will ensure that UOG and PPA resources are treated equally under the PEL and will promote the goals of the hybrid renewable market.

D. DRA Agrees With the Staff Proposal That Sales of Excess Energy Specified in Section 399.15(d)(3) Do Not Include Sales of Excess RECs (Question 6)

The staff proposal correctly treats sales of excess RECs as direct rather than indirect transactions. Section 399.15(d)(3) excludes indirect expenses from the PEL: "procurement expenditures do not include any indirect expenses, including … sale of excess energy."[2] The sale of excess energy is a sale of system power – or some similar sale of portfolio generation – that a utility may undertake as a result of over-generation or over-procurement. If this over-generation or over-procurement is renewable, then the sale of system power would be an indirect result of renewable procurement but the revenue would not count toward the PEL.

As part of optimizing their renewable portfolios, utilities have recently undertaken sales of excess RECs.[3] RECs represent the environmental and renewable attributes of renewable electricity, including the avoided greenhouse gas (GHG) emissions, and are used to show compliance with California's RPS requirements. The sale of excess RECs is not the same as the sale of excess energy. The Legislature identified the sale of excess energy as an indirect result of renewable generation.[4] Unused RECs, on the other hand, are not a result of over-generation but direct revenue obtained from the sale of the unit of RPS compliance. The sale of RECs is revenue and can and should count toward the PEL. From a policy standpoint, the Commission should encourage utilities to optimize their portfolios by selling excess RECs. The staff proposal to directly subtract payments received from RPS sales contracts from the procurement expenditures associated with that contract[5] is consistent with Section 399.15(d)(3).

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[2] California Public Utilities Code Section 399.15(d)(3).

[3] For example, see Advice Letter 2483-E.

[4] California Public Utilities Code Section 399.15(d)(3).

[5] Staff proposal, p. 18.

E. Forecasted Procurement Expenditures Should Be Based on the RNS Methodology and Should Assume the Maximum Generation Amount Contracted, Unless Shown Otherwise (Question 8)

DRA supports the staff proposal that procurement expenditures be forecasted based on the approved renewable net short (RNS) methodology and to generally assume the maximum generation amount contracted from facilities.

The RNS methodology allows the utilities to risk-adjust all projects in their RPS portfolios which are not yet online for potential failure to come online, among other factors.[6] A forecast based on the RNS methodology should be the most accurate prediction of a portfolio's generation and, therefore, a utility's RPS expenditures.

As the staff proposal notes, for facilities which are already online, utilities generally forecast generation based on the expected or maximum amount that may be annually procured according to the contract. Thus, forecasted expenditures can be calculated by multiplying a facility's contract price by the maximum generation that may be procured under the contract.[7] Should a utility wish to adjust the forecasted generation of a facility already in operation because that facility's historical generation has been substantially different from the contracted maximum generation amount, the utility may use the historical performance to adjust the costs associated with that facility within the PEL model. To do so, the utility must demonstrate that that assumption must be changed and provide the data to prove that the historical performance of that facility supports the change in assumption. Otherwise, the maximum amount of generation contracted must be assumed.

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[6] August 2, 2012 Administrative Law Judge Ruling (1) Adopting the Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology Into The Record, and (3) Extending the Date for Filing Updates to 2012 Procurement Plans, Attachment A, p. 8.

[7] Staff proposal, p. 33 (footnote 33).

F. Both Approved and Executed But Not Yet Approved Contracts Should be Included in the PEL Methodology (Question 9)

DRA supports the staff proposal to include both approved contracts and those that have been executed but not yet approved by the Commission in the PEL methodology. Using the price of executed contracts to forecast annual procurement expenditures should more accurately predict an IOU's expected expenditures for projected energy deliveries than the generic price derived from the RPS Calculator which will be used to forecast the costs of generation needed to fill the RNS.[8] Excluding executed but not yet approved contracts would cause the utility to have a larger RNS and rely on cost assumptions of a generic future resource instead of the price of an executed contract that more accurately reflects the current market. In addition, at any particular time, the set of contracts which have been executed but not yet approved is small. So, while it is possible that the Commission may not approve an executed contract, may fail, or may be amended at a later point, the impact of this difference on the overall PEL is likely to be marginal. Further, the inclusion of executed but not yet approved contracts in the PEL methodology should not influence the Commission's deliberative process of approving or rejecting such contracts.

G. The RNS Calculation Within the PEL Must Assume Compliance With All Laws and Requirements But Should Avoid Any Additional Assumptions. RNS Costs Should Be Drawn From the RPS Calculator so Long as Bid Data Are Confidential (Question 10)

DRA agrees with the staff proposal that the utilities should use the RNS method to calculate the PEL because it provides the most current data to forecast procurement. DRA also supports the staff proposal's exclusion of any assumptions regarding the technologies, sizes, and other aspects of the facilities that may go on to fill the utilities' short positions.

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[8] Staff proposal, p. 20.

The RNS cost calculation within the PEL methodology should assume compliance with all current laws. If a particular technology, such as bioenergy, is required, then the utilities must forecast that a portion of the RNS be filled with the requisite amount of bioenergy. The RPS Calculator can be the source for the cost assumption for that specific resource. The same should hold true of programs with minimum procurement requirements such as the renewable auction mechanism (RAM) and the feed-in tariff (FIT). Finally, the utilities must comply with limitations on portfolio content categories.[9] Beyond these regulatory requirements, however, the Commission and utilities should avoid assuming any specific mix of technology types, facility sizes, UOG and PPA quantities and any other assumptions which would be based on subjective predictions. Instead, a single price for a generic future renewable resource can be developed from the resource costs within the RPS calculator. Then, a single generic price per megawatt-hour can be multiplied by the number of megawatt-hours that comprise a utility's RNS. This method is administratively much simpler than assuming a particular amount of specific resources to fill the RNS. The utilities have already procured the majority of the resources needed to comply with 33% RPS goals[10] so the RNS for each is quite small, at least for the foreseeable future. Therefore, whatever forecasting errors may be caused by this administratively simpler method will not have a large effect on the utility's PEL.

Each utility's RPS solicitation data is likely a more current set of market-based prices than the RPS Calculator. However, those data are currently confidential whereas the RPS Calculator is public. If the confidentiality of bids changes in the future, the Commission may wish to reconsider the source of resource cost assumptions for each utility's RNS.

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[9] D.11-12-052.

[10] See Preliminary 33% RPS Compliance Reports of the IOUs at http://www.cpuc.ca.gov/PUC/energy/Renewables/.

Finally, the indirect costs associated with RPS resources needed to fill the RNS most likely cannot be considered within the PEL because Section 399.15(d)(3) excludes indirect costs from the PEL.

H. The PEL Must Account for Total RPS Procurement Costs, Not Merely the Marginal Costs of RPS Compared to Conventional Generation. The Determination That a PEL Will Prevent Disproportionate Rate Impacts Must Rely on a Comparison to a Pre-Determined Acceptable Annual Rate Increase Attributable to Renewables (Questions 11 and 13)

The staff proposal appropriately recommends that the PEL account for total RPS procurement costs, not only the marginal costs associated with RPS procurement compared to conventional resources. Although accounting for the marginal costs of RPS would account for any additional costs of renewables compared to non-renewables and may more accurately represent the "costs of RPS" because load not served with renewable electricity would still almost certainly be served with another resource, calculating the additional costs of renewables would require establishing a conventional procurement cost to which RPS costs are marginal and that would likely produce unintended consequences.

California previously had a generic conventional procurement cost called the Market Price Referent (MPR) and marginal RPS costs were calculated based on that number.[11] The MPR was a calculation of a proxy natural gas resource that would have hypothetically served load in the absence of renewables. However, the introduction of the MPR into the renewable marketplace led to severe price distortions and anti-competitive behavior wherein many bidders into RPS solicitations simply bid the exact MPR applicable to their project or some derivative thereof instead of a price derived solely from market signals. After a number of years of such price distortions, the Legislature deleted MPR provisions in Public Utilities Code Section 399.15. Ratepayers would be best served by avoiding a repeat of that situation and not introducing any

[11] See http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr.

administratively-set price into the renewable marketplace. Since calculating any marginal cost of renewables requires an administratively-determined non-renewable cost assumption, the total costs of renewables should be counted toward the PEL.

DRA recommends in Section J below that the total cost of renewables be accounted for in the PEL, including associated indirect costs, to determine whether a "disproportionate rate impact" will occur. Instead of only using the ratio of RPS expenditures to total revenue requirement, DRA proposes that the finding of disproportionate rate impact actually use the associated rate increase that will follow from a proposed PEL, along with its indirect costs. A "rate impact" is the effect of a certain action on rates. The rate increase that follows from a certain action – in this case the RPS program – is the appropriate measure of such an "impact." DRA proposes that the Commission establish a rate increase level that will be considered unacceptable, or "disproportionate", against which each PEL will have to be compared.

DRA recommends that, as part of the determination of the biennial PEL-setting process, the Commission direct each utility to calculate the proportion of its most recent rate increase that can be attributable to renewable costs. These calculations should include both the direct and indirect costs of renewables and be broken out by year going forward for ten years of the PEL. If the average rate increase attributable to renewables is above a pre-determined acceptable level – DRA proposes as a starting point for discussion when a 5 percent limitation on annual rate increases attributable to renewables is reached – then the Commission must find a disproportionate rate impact.

I. The Proposed Methodology Correctly Accounts For All RPS Procurement, Not Only the Procurement Associated with the RNS (Question 12)

DRA supports the staff proposal that the PEL not only apply to the RNS, but to all applicable direct expenditures. The PEL is intended as an accounting mechanism to make renewable costs available to stakeholders, legislators, and the public. Including only the small portion of RPS procurement that comprises the RNS diminishes that goal.

J. The Commission Determination That a Proposed PEL Would Cause a "Disproportionate Rate Impact" Must Include Indirect Costs Because They Contribute to the Rate Impact of Renewables (Question 14)

DRA mostly agrees with the proposed methodology for determining the PEL, but DRA recommends that the methodology to determine disproportionate rate impacts include both direct and indirect costs. Direct costs are the costs of building, owning, and operating eligible renewable energy resources in the case of UOG and the costs of the PPA in the case of third-party owned facilities. Indirect costs include integration, transmission upgrades, and distribution upgrades, among others. These costs are typically not factored directly into RPS PPA or UOG costs but are recovered from ratepayers through rates via Commission approval of specific transmission lines, gas-powered facilities intended for integration, CAISO imbalance charges, and other charges. Regardless of how those costs are approved, ratepayers pay for all of these renewable energy components. Therefore, to accurately determine if the 33 percent RPS program has created "disproportionate rate impacts," the Commission should consider all costs of renewables, both direct and indirect.

Public Utilities Code Section 399.15(c) requires the Commission to limit a utility's procurement expenditures for all eligible renewable energy resources. [12] The Commission must: (1) set the limit at a level that prevents disproportionate rate impacts; and (2) not count any indirect expenses, including, "imbalance energy charges, sale of excess energy, decreased generation from existing resources, transmission upgrades, or the costs associated with relicensing any utility-owned hydroelectric facility as procurement expenditures."[13] While Section 399.15(d)(3) prohibits the Commission from considering any indirect costs as procurement expenditures, nothing in the statute prohibits including indirect costs in any determination of disproportionate rate impacts. Further, because the design and monitoring of the PEL are separate from the

[12] California Public Utilities Code Section 399.15(c).

[13] California Public Utilities Code Section 399.15(d)(1) and (d)(3).

determination of disproportionate rate impact they need not include the same set of costs. The Commission should consider both direct and indirect costs incurred by RPS because all of those costs will contribute to the rate impact of RPS. Thus, a disproportionate rate impact cannot be determined without considering all costs.

DRA proposes that each time a new PEL is approved, the Commission also determine a threshold for disproportionate rate impact that includes all RPS costs. As an initial starting point for discussion, DRA proposes a total rate impact limitation of 5 percent annually. In other words, rates should not be allowed to increase more than 5 percent annually attributable to the total costs of renewable contracts, renewable UOG facilities, all of the various renewable programs, and the indirect costs that can be attributed to RPS. Indirect costs should include: (1) transmission and distribution costs, or the proportion of each transmission or distribution upgrade that can be attributed to renewables; (2) integration costs – imbalance charges, new non-renewable power plants and other instruments needed for renewable integration – or the proportion thereof attributable to renewables; and (3) other indirect costs such as administrative costs.

K. Disproportionate Rate Impact Should be Calculated Over the Same Time Frame as the PEL (Question 15)

For consistency and simplicity, DRA recommends that assessment of a disproportionate rate impact should be calculated over the same time frame as the PEL – ten years. In order to determine whether a rate impact is disproportionate, the pre-determined rate impact cap should be compared to the average rate increase attributable to renewables as forecasted over the next ten years.

L. DRA Supports the Staff Proposal to Update the PEL Inputs and Assumptions at Each Key Decision Point Along the Procurement Continuum (Question 18)

DRA agrees with the staff proposal that the utilities should update the PEL inputs (i.e., Table 2 of Attachment D of the Ruling) at each key decision point along the procurement continuum. Updating inputs and assumptions at key decision points will assure that the PEL is as accurate and as up-to-date as possible. This will enable the utilities to refine their portfolio analysis regularly, make the best procurement decisions possible, and allow decision-makers and the Procurement Review Group (PRG) to make the best recommendations and decisions with respect to the utilities' renewable procurement.

M. Recalculation of the PEL Every Two Years is a Reasonable Time Frame to Inform Procurement Decisions and Keep the PEL Updated (Questions 19 and 20)

DRA agrees with Staff's proposal for the PEL to be recalculated every two years, as it strikes a reasonable balance between the administrative burden of recalculating the PEL and keeping the calculation current and useful. The LTPP similarly revises its inputs every two years. The most appropriate proceeding within which to update the PEL is the active RPS Order-Instituting Rulemaking (OIR).

N. New or Emerging Technologies and Procurement Requirements Will be Factored Into the PEL When it is Updated Every Two Years (Question 22)

The predicted costs of any law or policy the Commission is directed to implement should be factored into the PEL ratio when it is recalculated every two years by being incorporated into the forecasts of the revenue requirement (the denominator of the PEL ratio) and/or the RPS expenses (the numerator of the PEL ratio). The RNS methodology, which comprises a part of the numerator, will account for any new requirements that have not yet been directly contracted for. The PEL methodology does not need to expressly account for new or emerging technologies or procurement requirements as soon as they are issued.

O. No Additional Measures Are Necessary to Assure that Portfolio Optimization and Cost Minimization Are Accounted For in the PEL. DRA Recommends a New Phase in this OIR to Address These Issues (Questions 23 and 24)

Regarding the role of portfolio optimization within the PEL, DRA agrees with the staff proposal that any utility's sales of excess RECs should be directly subtracted from RPS expenditures. The utilities should include other strategies, such as purchases of different types of RPS products, in the PEL within the RPS expenditures forecast.

DRA believes that both portfolio cost minimization and portfolio optimization,[14] while related to PEL, are distinct and important enough to merit in-depth discussion and analysis in a separate phase of this proceeding. Portfolio cost minimization and optimization were identified in the original scoping memo but have not yet been addressed,[15] and should be addressed concurrently with the PEL methodology given the interrelated nature of portfolio cost minimization and optimization and the effect their strategies will have on the large amount of banked RECs the utilities are expected to have in Compliance Periods 2 and 3.

P. Utilities Should File a Tier 3 Advice Letter When They Have Reached 90 Percent of Their PEL or When They Forecast That They May Not Be Able to Meet RPS Requirements Within the PEL (Question 26)

DRA supports the staff proposal that a Tier 3 advice letter process be used to show that a utility's PEL is insufficient to support the projected costs of meeting its RPS obligations. The advice letter should be filed as soon as a utility determines that it has reached or will soon reach 90 percent of its PEL and has not yet met its 33 percent RPS target. This will avert the utility exceeding its PEL because it is obligated by executed PPAs to keep paying for renewable deliveries. Otherwise, the utility may actually be forced to exceed its PEL simply as part of its executed contractual obligations.

Within the Tier 3 advice letter, the utility should demonstrate what errors, if any, were made in its original calculations or what changes have occurred that preclude it from meeting its RPS obligations within the PEL. If the Commission does determine that a utility has met its PEL and should stop procuring renewables, the determination need only last until the next recalculation of the PEL.

[14] DRA understands cost minimization and portfolio optimization to mean maintaining a reasonably-sized and cost-effective bank given the expected needs and generation in a given compliance period using tools such as sales of excess RECs and the purchase of bundled or unbundled products to avoid any reasonably anticipated shortfalls in procurement.

[15] Order instituting rulemaking regarding implementation and administration of the Renewables Portfolio Standard Program, issued May 10, 2011, at 11. "6.8 Other issues identified by parties or the Commission."

Q. The De Minimis Requirement Can be Interpreted As a Total Cap on the Rate Impact of the RPS or as a Requirement Imposed on Additional RPS Procurement After the PEL is Reached (Question 27)

The term "de minimis"[16] has been used broadly and has been applied differently, depending on the context.[17] There are two ways to consider the "de minimis" statement in Section 399.15(f): either "de minimis" refers to the total rate impact of the RPS program or merely to any additional renewable procurement undertaken after the PEL is reached. DRA recommends the latter interpretation. If the Commission adopts this interpretation, then it should consider the net market value (NMV) of any renewable procurement undertaken toward RPS obligations after the PEL is reached. If the Commission adopts the former interpretation, then it should refer to the proposed 5 percent cap on the total rate impact due to renewables.

In response to Questions 11, 13 and 14, DRA suggests an annual 5 percent cap on the rate impact due to renewables as a starting point for parties' consideration and further analysis. DRA does not in any way suggest that a 5 percent annual rate impact is so "trivial, insignificant or so meager and fragmentary"[18] that a ratepayer would not notice that cost on his or her utility bill. Nevertheless, it may be a realistic cap on for total renewable rate impact from both direct and indirect costs. Prior to the November

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[16] Section 399.15(f) provides that if the cost limitation for an electrical corporation is insufficient to support the projected costs of meeting the renewables portfolio standard procurement requirements, the electrical corporation is authorized to refrain from entering into new contracts or constructing facilities beyond the quantity that can be procured within the limitation, unless eligible renewable energy resources can be procured without exceeding a de minimis increase in rates, consistent with the electrical corporation's general procurement plan.

[17] The legislative record of Section 399.15 does not provide a clear definition or context of how the Commission should interpret "de minimis." Some authorities have determined that "de minimis" indicates something that is trivial or insignificant. *Cavalier v. Random House, Inc.*, 297 F.3d 815 (9th Cir. 2002). Others have determined that an act has a "de minimis" effect if the act is so meager and fragmentary that a reasonable person would not notice the act or its effect. *Fisher v. Dees,* 794 F.2d 432 (9th Cir. 1986). The California Civil Code has stated that when referring to maxims of jurisprudence, such as "de minimis," the law "will not concern itself with trifles." See Cal. Civ. Code § 3533 (Lexis 2013).

[18] *Supra,* footnote 4.

workshop, DRA will request data from the utilities to be made publicly available -- to the extent possible -- that will estimate the current rate impact of renewables as a starting point for discussion.

If the de minimis requirement can be interpreted as only applying to *additional* procurement toward RPS targets after the PEL is reached, then DRA suggests that the Commission consider the NMV of the proposed renewable procurement or, alternatively, whether the proposed project is competitive against non-renewable facilities. If the NMV of a project is positive – or if it can be shown that it is competitive with non-renewables, then the rate impact of the project should be negative and, therefore, less than de minimis.

R. Voluntary Increases in Renewable Procurement Need Not Count Against the PEL if the Utility Does Not Wish to Count Them as RPS-Eligible. These Types of Resources Will Need to be Competitive With Non-Renewables (Question 28)

DRA considers a "voluntary increase in procurement" to mean that a utility wishes to procure renewable energy beyond the quantities (including the minimum margin of over procurement) mandated by the Commission, and will not count the procurement towards the utility's RPS obligations in the PEL's 10-year period or beyond. If the utility will not use voluntarily procured renewables toward any RPS obligations now or in the future, then those resources need not be counted in the PEL because the PEL is an expenditure limitation on costs incurred as part of the RPS program. However, any renewable resources procured voluntarily must be competitive outside of any renewable obligation. The utility should be required to demonstrate that the resource in question provides better ratepayer value than competing offers, including non-renewable ones. Further, even if a utility still has "room" in its PEL and has already met its 33 percent RPS obligations, it should not be allowed to procure renewables under the "extra room" in the PEL. In short, both in the case where a utility has reached its PEL and in the case where a utility has met its RPS obligations, it should be permitted to continue to procure renewable resources only if they are competitive compared to non-renewable resources.

If a utility wants voluntary renewable procurement beyond what the utility is required to procure to be considered RPS-eligible and count toward the utility's RPS obligations (e.g. it will be banked for future procurement obligations beyond the rolling 10-year period), then this "voluntary" procurement must be treated similarly to a utility's mandatory RPS procurement, and should still be counted under RPS expenses in the PEL methodology.

III. CONCLUSION

DRA requests that the Commission adopt its recommendations to: include indirect costs in the determination of disproportionate rate impact; base the finding of disproportionate impact on the expected annual rate increase attributable to renewables; and allow voluntary over-procurement of renewables so long as that procurement is deemed competitive with non-renewables.

Respectfully submitted,

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September 26, 2013

VERIFICATION

I, Iryna A. Kwasny, am counsel of record for the Division of Ratepayer Advocates in proceeding **R.11-05-005**, and am authorized to make this verification on the organization's behalf. I have read **THE DIVISION OF RATEPAYER ADVOCATES COMMENTS ON STAFF PROPOSAL FOR A METHODOLOGY TO IMPLEMENT PROCUREMENT EXPENDITURE LIMITATIONS FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM** filed on **September 26, 2013**. I am informed and believe, and on that ground allege, that the matters stated in this document are true. I declare under penalty of perjury that the foregoing is true and correct.

Executed on **September 26, 2013**, at San Francisco, California.

/s/ Iryna A. Kwasny
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