BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

ALTERNATE PROPOSAL OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, THE ENERGY PRODUCERS AND USERS COALITION, AND THE CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION TO THE STAFF PROPOSAL FOR A METHODOLOGY TO IMPLEMENT PROCUREMENT EXPENDITURE LIMITATIONS FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM

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This alternate proposal is submitted pursuant to the October 11, 2013 e-mail approval from Administrative Law Judge Simon of the request by Large Users for permission to file and serve this alternate proposal after the original date set for filing.

These comments are submitted in response to the "Administrative Law Judge's Ruling Requesting Comments on Staff Proposal for a Methodology to Implement Procurement Expenditure Limitations for the Renewables Portfolio Standard Program" (ALJ Ruling), dated July 23, 2013, pursuant to the schedule set by a subsequent Ruling on September 9, 2013. The California Large Energy Consumers Association[1] (CLECA), the Energy Producers and Users Coalition[2] (EPUC) and the California Manufacturers and Technology Association (CMTA)[3]

1 CLECA is an ad hoc organization of large, high load factor industrial electric customers of Southern California Edison Company and Pacific Gas and Electric Company. CLECA has been an active participant in Commission regulatory proceedings since 1987.

2 EPUC is an ad hoc group representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, Chevron U.S.A. Inc., ExxonMobil Power and Gas Services Inc., Phillips 66 Company, Shell Oil Products US, Tesoro Refining & Marketing Company LLC, THUMS Long Beach Company, and Occidental Elk Hills, Inc.

3 CMTA works to improve and enhance a strong business climate for California's 30,000 manufacturing, processing and technology based companies. Since 1918, CMTA has worked with state government to develop balanced laws, effective regulations and sound public policies to stimulate economic growth and create new jobs while safeguarding the state's environmental

(collectively, Large Users)[4] jointly submit these comments.

I. INTRODUCTION AND SUMMARY

From 2003 to 2011, the RPS annual expenditures have nearly doubled for PG&E, rising from $512 million to $1,017 million and increased significantly for SCE, rising from $907 million to $1,341 million[5] In 2003, PG&E was at 11.5% RPS and SCE was at 16.6%; by 2011, PG&E was at 19.8% and SCE had reached 21.1%.[6] On a cents-per-kWh basis, RPS costs have also risen, going from 6.5 cents in 2003 to 7.3 cents in 2011 for PG&E and for SCE from 7.5 cents to 8.5 cents.[7]

While the mix of RPS resources has not changed dramatically over this historical time period, procurement of RPS solar power is expected rise significantly between now and 2020.[8] The RPS costs of solar PV went from 5.8 cents/kWh for SCE and 5.9 cents/kWh for PG&E in 2003 to 11.6 cents/kWh and

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resources. CMTA represents businesses from the entire manufacturing community -- an economic sector that generates more than $250 billion every year and employs more than 1.5 million Californians.

4 While CLECA/EPUC/CMTA have joined together in these comments, the parties reserve the right to participate separately in the proceeding as appropriate.

5 *See* Report to the Legislature in Compliance with Public Utilities Code Section 910 (Section 910 Report), dated March 2013, at 11 and 13 (available at http://www.cpuc.ca.gov/NR/rdonlyres/E214382A-A654-4CCD-927B-944370F197EB/0/Section910Report.pdf).

6 *See* Section 910 Report, at 2.

7 *See* Section 910 Report, at 12 and 14. In 2012, according to the Padilla Report to the Legislature, the weighted average PG&E RPS procurement costs appear to have increased further to 7.89 cents/kWh, while slightly decreasing for SCE to 7.86 cents/kWh. *See* The Padilla Report to the Legislature (Padilla Report 2012), dated March 2013, at 10 (available at http://www.cpuc.ca.gov/NR/rdonlyres/F0F6E15A-6A04-41C3-ACBA-8C13726FB5CB/0/PadillaReport2012Final.pdf)

8 *See* Renewable Portfolio Standard Quarterly Report, 3rd and 4th Quarter 2012 (RPS Status Report), at 5 (available at http://www.cpuc.ca.gov/NR/rdonlyres/2BC2751B-4507-4A38-98F5-F26748FE6A95/0/2012_Q3_Q4RPSReportFINAL.pdf) ("the relative contribution provided by different renewable technologies is forecast to shift dramatically by 2020 …to reflect a considerable increase in generation coming online from new solar PV and solar thermal generating facilities. These technologies are forecast to contribute 34% and 13%, respectively, of the state's total renewable generation by 2020.").

18.7 cents/kWh in 2011.[9] In 2012, the weighted average TOD-adjusted RPS procurement expenditure contract costs for solar PV was 17.26 cents/kWh (14.16 cents for SCE and 17.47 cents for PG&E); the 2012 weighted average TOD-adjusted RPS procurement expenditure costs for utility-owned solar PV was 19.8 cents/kWh (32.95 cents for SCE and 16.55 cents for PG&E).[10] Publicly available data does not support the supposition that RPS costs are going down. In fact, Staff assumes it is inevitable that, "*total RPS procurement costs will increase* from current levels to meet the 33% RPS procurement requirement" because of the jump from the existing 20% RPS to a 33% RPS.[11]

Regardless of these considerations, SB 2 (1X) mandates a "*cost limitation*" on RPS procurement. The law provides an off-ramp to prevent the 33% RPS from causing "*disproportionate rate impacts*."[12] If rate impacts of RPS procurement become disproportionate, unless additional procurement can be undertaken with only "*de minimis*" rate increases, the Investor Owned Utilities (IOUs) are excused from further RPS procurement.[13]

The overarching question of proportionality turns on what comparison is being made. SB 2 (1X) does not specify the comparison for its required determination of the rate impacts of the 33% RPS. Staff proposes setting 10-year rolling Procurement Expenditure Limitations (PEL) for each IOU, using a

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9 *See* Section 910 Report, at 12-14.

10 Padilla Report 2012, at 10.

11 ALJ Ruling, at 15.

12 PU Code §399.15(d)(1).

13 PU Code §399.15(f) ("If the cost limitation for an electrical corporation is insufficient to support the projected costs of meeting the [RPS] requirements, the electrical corporation may 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 long-term procurement plan established for electrical corporation pursuant to Section 454.5.").

"ratio of an IOU's RPS procurement expenditures to the IOU's total revenue requirement".[14] Staff's proposed comparison is inapt and will not serve to limit "disproportionate rate impacts" resulting from RPS costs; indeed, it mixes apples and oranges by comparing RPS procurement costs to a total revenue requirement that encompasses the full array of revenue requirements, thus masking the impact of the RPS costs. Accordingly, should the Staff Proposal be adopted, it must, at a minimum, be changed in three key ways.

II. RECOMMENDATIONS

Large Users recommend three key revisions to the Staff Proposal, a definition for the de minimis impact as well as revisions to the guiding principles.

A. Three Key Revisions Are Needed to the Staff Proposal

First, the staff's proposed rolling average PEL over a 10-year period should be replaced by a limit defined in terms of fixed, annual periods with regular, ongoing, annual updates.

Second, the ratio for purposes of comparing impacts to determine proportionality of IOU RPS procurement expenditures (i.e., the check for disproportionate impacts) should not use the IOU's total revenue requirement; instead, it should focus on RPS costs only. The future period (which Large Users propose as the next procurement year) to which the PEL would apply should compare the cost of forecast incremental RPS costs during that procurement year to the most recent total recorded RPS costs for an apples-to-apples comparison. Revising staff's ratio to an RPS to RPS comparison would better

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14 ALJ Ruling, at 9.

serve the stated goal of ensuring RPS costs do not cause disproportionate impacts, meets §399.15(d)(2) by counting the costs of all RPS procurement credited and §399.15(d)(3) by excluding indirect expenses.

Third, the Procurement Expenditure Limitation itself should also focus only on RPS costs and reflect approximated RPS costs[15] and the possibility of cancellation.[16] Relying on historical RPS procurement as well as forecast RPS procurement will accomplish both of these statutory goals. The PEL calculated in 2014 for 2015 should be equal to the following number: the product of [the average in $/MWh of the 2011-2013 annual RPS total costs] times [the annualized net short MWh, which is the difference between the forecast RPS MWh approved for 2014 and the forecast 2020 RPS MWh, divided by the number of years between 2015 and 2019], divided by [the actual total annual RPS costs from the most recent year (2013)].

Thus the numerator in the PEL ratio (calculated in 2014 for subject year 2015) should be calculated by:

- multiplying the average of the 2011 through 2013 total recorded RPS costs (expressed in $/MWh) by
- the annualized RPS net short MWh (the difference between the 2020 target RPS MWh and the forecast approved for 2014 RPS MWh, divided by the numbers of years between 2015 and 2019[17]).

The denominator in the 2015 PEL ratio should be the 2013 actual total RPS costs.

15 P.U.Code §399.15(c)(2).
16 P.U. Code §399.15(c)(3).
17 i.e., 5 years; this assumes that the utility meets the 2020 goal in 2019.

Once the PEL is set, it would be used to check the forecast RPS 2015 procurement (with a forecast incremental RPS procurement for 2015 as the numerator over the actual 2013 RPS costs as the denominator). If that ratio is less than or equal to the PEL ratio, the forecast 2015 procurement would not have a disproportionate rate impact. If that ratio is greater than the PEL, then the forecast procurement needs to be reduced to the point where it meets the PEL.

Including the indirect expenses, as proposed by staff, in the calculation of the Procurement Expenditure Limitation would contravene §399.15(d)(3).[18] These costs are supposed to be excluded; moreover, because indirect costs are varied and increasing, their inclusion could obscure the impact of RPS procurement. Transmission, distribution and other components of the annual revenue requirements are rising in response to a variety of pressures, including the 33% RPS, and will continue to increase. For example, the California Independent System Operator has forecast $7.2 billion in new transmission capital costs for the 33% RPS by 2023, and SCE has forecast new RPS-related transmission costs totaling $6.4 billion.[19] SCE's forecast new transmission could add up to $1.152 billion to SCE's annual revenue requirement.[20] Staff's proposed inclusion in the denominator of these costs - that are explicitly required to be excluded - would preclude isolation and containment of the direct RPS

[18] P.U.Code § 399.15(d)(3) ("Procurement expenditures do not include 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 facilities.").

[19] See Section 910 Report, at 7.

[20] $6.4 billion x 18% = $1.152 billion. *See* Section 910 Report, at 7.

procurement costs, preventing the Commission from meeting its statutory obligation.

To meet the SB 2 (1X) requirements, the Commission's RPS Procurement Expenditure Limitations must actually affect RPS procurement and prevent disproportionate rate impacts; they cannot be a rubber stamp approving all RPS procurement. The Staff's proposal, however, does not appear to be able to limit or contain too-costly RPS procurement. In fact, staff's "proposed methodology 'bakes in' the steady increase in required procurement by setting the PEL at the highest projected percentage for any one year during the 10-year period."[21] This approach fails to focus on RPS rate impacts and seems more geared towards achieving a 33% RPS regardless of cost. The Staff Proposal should be revised as recommended by Large Users.

B. De Minimis Impact Should Be a 2% Increase in Incremental RPS Costs

The determination of what a "de minimis" impact on rates would be for purposes of SB 2 (1X)'s "off-ramp" should be informed by the Legislature's specific definition of de minimis in another RPS context. § 399.12(h)(3)(A) sets at 2% the "de minimis" quantity of non-renewable fuel that a facility may use in producing a renewable energy credit.[22] Thus "de minimis" for purposes of an impact on rates from incremental RPS procurement should be defined as the impact of a less than 2% increase in the incremental RPS costs.

[21] ALJ Ruling, at 15.
[22] P.U.Code §399.12(h)(3)(A).

C. Revisions to Guiding Principles

Certain of the proposed guiding principles for the Procurement Expenditure Limitation are similarly misguided and require revision to regain the requisite focus of PUC Code 399.15(c) - (f) on rate impacts. Recommended changes to the guiding principles are in ***underlined italics***, and deletions are ~~strickenthrough~~:

- Rely on a transparent process;
- Reflect the *realistic* expected costs of achieving and maintaining the 33% RPS goal;
- ~~Realistically minimize~~ *Ensure* the costs of achieving and maintaining the 33% RPS goal *are proportionate*;
- ~~Facilitate coordination and consistency between the RPS and the Commission's long-term procurement planning proceeding (LTPP);~~
- ~~Encourage portfolio level optimization by IOUs~~. [Portfolio level optimization should be achieved by RPS Plan and the least-cost, best-fit process, not the cost containment mechanism]

The key recommended changes to the Staff Proposal are expanded upon in Section III in responses to certain of the ALJ Ruling's questions.

III. COMMENTS

While not answering every question in the ALJ Ruling,[23] the responses below focus on enabling the adoption of Procurement Expenditure Limitations that meets the mandated goal: prevention of excessive rate impacts. As requested, the questions with responses are identified and reproduced in blue.

1. Section 399.15(e) mandates that the Commission assess whether each electrical corporation can "achieve a 33-percent renewables portfolio standard by December 31, 2020, and maintain that level thereafter, within the adopted cost limitations."

[23] "No response" is indicated where Large Users do not offer a response; Large Users, however, reserve the right to later provide input on other parties' responses or in general even where a position is not taken herein.

- Does this require that the procurement expenditure limitation methodology extend beyond 2020? Explain why or why not.

The PEL methodology should extend beyond 2020. The requirement to achieve the 33% RPS does not end in 2020; a 33% RPS is expected to be maintained after 2020. Equally importantly, there is no sunset for the statutory sections on the cost limitations or the off-ramp in the case of disproportionate rate impacts. So long as the 33% RPS is to be maintained, RPS procurement will continue, new contracts will be executed and approved as old contracts expire and terminate; new utility facilities will be developed. As procurement continues, RPS costs will not stagnate; they will change over time.

Moreover, the recently passed Perea Bill (AB 327) would, upon execution by Governor Brown, enable the Commission to order RPS procurement in excess of 33%.[24] This change in law magnifies the importance of cost containment for renewables procurement. Accordingly, the 33% RPS procurement expenditure limitations should not only be revised as proposed herein, they should also be maintained after 2020.

2. Do you agree with Staff's proposal to use a rolling 10-year timeframe for setting and administering the PEL? Explain why or why not.

No, for a variety of reasons. Staff proposes to set and update the PEL by measuring annual forecast RPS procurement costs as a percentage of the utility's annual revenue requirement. The PEL would be initially set as the highest year's percentage value in the 10-year forecast (i.e., 2014-2023). It would be reset every two years, again by calibrating to the highest percentage value of the then-current 10-year forecast.

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24 See AB 327, revising section 399.15(b)(3).

As Staff readily acknowledges, its proposal guarantees a "steady increase in required procurement by setting the PEL at the highest projected percentage for any one year during the 10-year period."[25] As the percentage of RPS procurement grows, so grows the PEL. In other words, the PEL does not *contain* costs, it simply *tracks* the RPS as it grows as a percentage of revenue requirement. In addition, if RPS prices per MWh eventually come down, the Staff Proposal creates headroom for additional procurement, which could result in unnecessary spending; such overspending inherently violates the intent of the expenditure limitation provision of SB 2 (1X). The Commission should revise the RPS Procurement Expenditure Limitations to not be applied on a 10 year rolling average basis.

Staff also proposes enabling continued RPS procurement in excess of the procurement expenditure limitation, based on an unsubstantiated expectation that costs in a future year (or years) could be below the limitation.[26] Even if newly contracted per MWh costs were to decline in the future, which is not in evidence, the costs of new RPS MWh under previous contracts could easily escalate. This aspect of the proposed rolling 10-year period is very troubling from a ratepayer perspective; it effectively undermines the notion of a cap. A 10-year rolling average seems unworkable for purposes of containing costs. It should be changed to a single year, fixed percentage.

- Do you support a rolling PEL timeframe, but spanning some other amount of time? Explain what time period is preferred and why.

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[25] ALJ Ruling, at 15.
[26] ALJ Ruling, at 14, footnote 15.

No. The Procurement Expenditure Limitations, which should compare a forecast incremental RPS generation revenue requirement to an actual historical RPS generation revenue requirement, should be applied annually, not over a rolling timeframe. Again, a rolling timeframe could wrongly enable continued RPS procurement in excess of the cost limitation due to unsubstantiated assumptions regarding costs of future procurement within the rolling timeframe. This could lead to disproportionate rate impacts.

- Should the PEL timeframe span a fixed amount of time? If yes, please suggest an amount of time and justify the choice.

Yes. A one year timeframe would meet the statute's specific requirement that the Procurement Expenditure Limitations be an "annual cost limitation".[27] The Staff Proposal fails to meet this requirement.

3. No response is provided on longer-term timeframes for the Procurement Expenditure Limitations, as annual limitations are required.

4. Should the PEL expire after an IOU achieves 33% of its retail sales from RPS eligible resources for a compliance period? Why or why not? Should the PEL be reinstated if the IOU falls below 33% in a subsequent compliance period? Why or why not?

No, the limitations should not expire, because the 33% requirement does not expire, and the limitations are required by statute to be an annual cost limitation for each utility.

5. Section 399.15(c)(2) provides that, in establishing the procurement expenditure limitation, the Commission shall rely on "procurement expenditures that approximate the expected cost of building, owning, and operating eligible renewable energy resources."

Section 399.15(d)(3) provides that "procurement expenditures do not include any indirect expenses, including imbalance energy charges, sale of excess energy, decreased generation from existing resources, transmission upgrades,

[27] PU Code Section 399.15(g)(2)(A).

or the costs associated with relicensing any utility-owned hydroelectric facilities."

The Large Users' proposed revisions to the Staff Proposal rely on historical, recent RPS expenditures to reflect anticipated costs of RPS, as required by the statute, and the revisions only consider RPS procurement expenditures; indirect expenses are excluded, as required by the statute. These proposed revisions to the Staff Proposal better conform to the statutory requirements.

No response provided at this time to the questions on Section 399.15(c)(2) and (d)(3).

6. Section 399.15(d)(3) provides:
Procurement expenditures do not include 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 facilities.

The Large Users' proposed revisions to the Staff Proposal focus only on RPS procurement expenditures and thus the revised proposal complies with this statutory requirement that indirect expenses be precluded. The Staff Proposal, without modification, would not comply with the requisite exclusion of indirect expenses.

No response provided at this time to the questions on Section 399.15(d)(3)

7. Section 399.15(d)(2) provides that "the costs of all procurement credited toward achieving the renewables portfolio standard" will count towards the procurement expenditure limitation.

- For purposes of the PEL, how should an IOU's costs associated with RPS-eligible UOG facilities be accounted for? Is it necessary for this treatment to be comparable to the costs associated with a PPA?

The IOU's costs should be accounted for as they are recovered in rates; no readily-apparent reason calls for "comparable" (i.e., levelized) treatment of UOG to costs associated with a PPA. For example, the Section 910 Report excludes the costs of SCE's Solar PV Program utility-owned facilities because of the first year capital expenditures.[28] But the energy from the Solar PV Program, including that from the utility-owned facilities, is credited towards SCE's RPS procurement. The costs should likewise be counted in the procurement expenditure limitation. In 2012, SCE's RPS procurement expenditures for its utility-owned solar averaged 0.3295 cents per kWh; the utility's recovery of capital costs is reflected in rates. The focus of the renewables Procurement Expenditure Limitation is supposed to be the rate impact; accordingly, the costs should be included as they are reflected in rates.

- How do UOG costs differ depending on resource type? How should these differences be treated in the PEL?

No response provided at this time.

- How, if at all, would the treatment of indirect costs associated with UOG differ from that of contracted resources?

No response provided at this time.

- Do you agree with Staff's proposal to use the annual revenue requirement associated with UOG facilities? What are the pros and cons of this approach?

Generally, yes.

- Should a UOG facility's levelized cost of energy (LCOE) be used instead of revenue requirements? Explain why or why not.

No, because that is not how the UOG costs are recovered in rates; if the UOG costs are levelized, the RPS costs in rates and the RPS impact on rates will be understated.

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28 Section 910 Report, at 12.

- If yes, identify specific costs that should or should not be included in the LCOE calculation for UOG facilities and a detailed methodology for calculating LCOE of UOG facilities. Should some other method be used? Please describe and support the choice presented.

LCOE should not be used for the calculation of the UOG RPS facilities.

- Please explain why your preferred methodology for accounting for UOG costs is appropriate for purposes of the RPS procurement expenditure limitation.

UOG costs should be reflected as they are recovered in rates (i.e., not on a levelized basis), to accurately reflect the rate impact.

- How should the costs of contracts that set energy payments indexed to actual market prices at the time of generation be accounted for in future years?

No response provided at this time

- Please identify any other contractual arrangements that may need special consideration for purposes of the PEL, including how the costs of such arrangements should be accounted for in future years.

If a contract has a known future balloon payment, e.g., in year 3 of the contract, and the adopted PEL, contrary to our recommendation, covers multiple years including year 3 instead of a single year, then that known future balloon payment should be included in the costs for year 3.

8. How should forecasted procurement expenditures be calculated for contracts with generation facilities that are already in operation?

- Do you agree with Staff's proposal to rely on forecasted expenditures that are based on an IOU's RNS methodology?

Generally, but the PEL should be modified as proposed herein.

- For the purpose of setting the PEL, should forecasted procurement expenditures be based on a historic average for each operating facility if historic generation data exist? If so, how many years should be averaged?

Yes; a three year historical average of recorded costs should be used. The PEL calculated in 2014 for 2015 should be equal to the following number: the product of [the average in $/MWh of the 2011-2013 annual RPS total costs] times [the annualized net short MWh, which is the difference between the forecast RPS MWh approved for 2014 and the forecast 2020 RPS MWh, divided by the number of years between 2015 and 2019], divided by [the actual total annual RPS costs from the most recent year (2013)].

9. Do you support Staff's proposal to include executed contracts in the PEL methodology? Or, should only contracts that have been approved by the Commission be included? Why or why not?

Yes. Executed contracts should be counted in checking the PEL (in the numerator as part of the forecast incremental RPS costs), but only delivered (approved) contracts should be counted in setting the PEL (see page 5-6). This would allow the Commission the opportunity to reject contracts pending approval that would put an IOU above its limit.

10. What is the role of the RNS in setting the PEL?

The PEL calculated in 2014 for 2015 should be equal to the following number: the product of [the average in $/MWh of the 2011-2013 annual RPS total costs] times [the annualized net short MWh, which is the difference between the forecast RPS MWh approved for 2014 and the forecast 2020 RPS MWh, divided by the number of years between 2015 and 2019], divided by [the actual total annual RPS costs from the most recent year (2013)].

11. The RPS procurement expenditure limitation methodology proposed by Staff measures an IOU's total RPS procurement costs and not the marginal cost (or savings) associated with RPS procurement compared to conventional resources for electric generation and capacity.

- Do you agree that this methodology is the appropriate means of setting the limitation on RPS procurement expenditures?

No; but not necessarily because marginal costs should be used. (Notably, the statute does not call for a marginal cost analysis.) The methodology should be revised to compare forecast incremental RPS costs to historical RPS generation revenue requirement.

- If you do not agree, what methodology should be used? Any alternate proposal must explain how it meets the requirements and provisions of Sections 399.15(c)-(g), in particular, Section 399.15(d)(1), which specifies that the PEL must be "set at a level that prevents disproportionate rate impacts." Note, this ruling has specific requirements for how a party must present an alternative methodology.

Large Users recommend three changes to Staff's methodology:

1. Use a fixed, one-year period, rather than a rolling, 10-year average.

2. The ratio for purposes of comparing impacts to determine proportionality of IOU RPS procurement expenditures should not use the IOU's total revenue requirement; instead, it should focus on RPS costs only. The future period (which Large Users propose as the next procurement year) to which the PEL should apply should compare the cost of forecast incremental RPS costs during that procurement year to the most recent total recorded RPS costs for an apples-to-apples comparison. Revising staff's ratio to an RPS to RPS comparison would better serve the stated goal of ensuring RPS costs do not cause disproportionate impacts, meets §399.15(d)(2) by counting the costs of all RPS procurement credited and §399.15(d)(3) by excluding indirect expenses.

3. The Procurement Expenditure Limitation itself should also focus only on RPS costs and reflect approximated RPS costs[29] and the possibility of cancellation.[30] Relying on historical RPS procurement as well as forecast RPS procurement will accomplish both of these statutory goals. The PEL calculated in 2014 for 2015 should be equal to the following number: the product of [the average in $/MWh of the 2011-2013 annual RPS total costs] times [the annualized net short MWh, which is the difference between the forecast RPS MWh approved for 2014 and the forecast 2020 RPS MWh, divided by the number of years between 2015 and 2019], divided by [the actual total annual RPS costs from the most recent year (2013)].

Large Users do not believe these recommended changes to the methodology constitute an alternate proposal.

12. The RPS procurement expenditure limitation methodology proposed by Staff measures an IOU's total RPS procurement costs and not the incremental costs for RPS procurement or ownership agreements to achieve and maintain the 33% RPS procurement quantity requirements.

- Do you agree that this methodology is the appropriate means of setting the limitation on RPS procurement expenditures?

No. For purposes of the numerator, the forecast incremental RPS costs should be used. Measurement of the total RPS costs is appropriate, however, in determining the denominator.

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29 P.U.Code §399.15(c)(2).

30 P.U. Code §399.15(c)(3).

- Should the PEL apply only to the RNS (which by definition is necessary RPS-eligible procurement that has not yet been contracted for)? Why or why not?

No, because the RNS is not the only procurement for which the IOUs get RPS credit. Section 399.15(d)(2) provides that "the costs of all procurement credited toward achieving the renewables portfolio standard" will count towards the procurement expenditure limitation. Thus the limitation should apply to limit or stop all RPS procurement, and specifically, to executed but not-yet-approved RPS contracts and all "ongoing" RPS programs, e.g., FITs or the RAM. ALL RPS procurement should stop if the limitation is hit.

13. Section 399.15(d)(1) specifies that the PEL must be "set at a level that prevents disproportionate rate impacts." …

- Do you agree with Staff's proposal that the Commission use the ratio of RPS procurement expenditure to revenue requirement as the basis to determine whether a potential rate impact would be "disproportionate?" Explain why or why not.

No. The comparison should be on an apples-to-apples basis and compare RPS procurement costs to RPS procurement costs. Staff's proposed comparison fails to focus on cost of procurement credited towards the RPS and includes indirect expenses in the Procurement Expenditure Limitation through its use of the total revenue requirement; this would contravene Section 399.15(d)(3)'s mandated exclusion of such costs. Large Users recommend that the numerator for the ratio to determine proportionality of impact reflect the incremental RPS procurement expenditures forecast for the subject year.

- Should the Commission use some other method as the basis to determine whether a potential rate impact would be "disproportionate?

The Commission should modify the Staff Proposal and not use the IOU's total revenue requirement in the comparison. A comparison of forecast incremental

RPS costs to the historical total RPS costs (as opposed to the IOU's total revenue requirement) would serve as a better basis to determine proportionality of impact because it focuses on RPS costs. The current Staff Proposal basically takes the "highest" potential RPS costs from a 10-year forecast as compared to a forecast, escalated total IOU's revenue requirement; there is no sound basis for the subsequent proposed conclusion that the highest forecast cost would not lead to a disproportionate rate impact.

- Should the Commission use some other baseline as the denominator, e.g., the IOU's generation rate component of revenue requirements, as the basis to determine rate impact? Please explain and provide quantitative examples, if relevant.

Use of the generation revenue requirement as the denominator would be an improvement over use of the entire revenue requirement, but focusing on just the RPS component of the generation revenue requirement most closely conforms to the statutory requirements.

- Should the Commission use an evaluation of the costs and benefits of RPS-eligible resources compared to the costs and benefits of a scenario of procurement of the same volume of electricity from generation sources that are not RPS-eligible, e.g., a combined cycle gas turbine generation facility? Please explain and provide quantitative examples for how such a methodology would be employed, if relevant.

No response at this time.

14. What criteria should the Commission use to determine whether the rate impact of a proposed PEL would, or would not, be "disproportionate?"

- Should different methodologies be used to set the PEL itself, according to the requirements set in Section 399.15(c), and the calculation that is used as the basis for the Commission to determine whether a potential rate impact is "disproportionate?" For example, for the purpose of determining whether RPS procurement costs will result in a disproportionate rate impact, should significant indirect costs be added to RPS contract costs, even if the Commission interprets Section 399.15(d)(3)to prevent the use of such costs in setting the PEL? (i.e., such costs may not be part of the numerator in the PEL formula proposed by Staff.)

Staff inappropriately splits hairs by saying that the excluded indirect costs can be included for the denominator but not the numerator for setting the procurement expenditure limitation. Despite their statutorily-mandated exclusion from the annual cost limitation, the additional transmission costs associated with a 33% RPS are very high. The impact on rates of new RPS-related transmission should not serve to mask the impact of RPS procurement on rates. This would doubly obscure the fact that these costs are caused by RPS procurement. ***If the costs are not in the numerator, they should not be in the denominator.***

Given the exclusion of these "indirect" but very real and very high costs of the RPS, the Commission must err on the side of caution and ratepayer protection in setting the annual procurement expenditure limitations. For the ongoing evaluation of proposed RPS procurement, protection against excessive costs and disproportionate ratepayer impacts must be paramount, not promotion of renewables procurement for RPS at any cost.

- For purposes of the PEL, what adjustments, if any, should be made to the expenditures included in an IOU's revenue requirement in the denominator of the formula proposed by Staff? What specific adjustments should be made? Why or why not?

The denominator should be limited to the total procurement expenditures for renewable resources for the most recent year; otherwise, the comparison will not be an apples-to-apples comparison, and the use of the total revenue requirement would mask the impact of the RPS.

15. Over what time period should the Commission assess whether a potential rate impact is "disproportionate?"

The statute states plainly that the cost limitation is to be an “annual cost limitation.”[31] Given this language, it is difficult to see how anything but a 12-month period for the required assessment could or should be reasonably considered. At a minimum, an annual calculation of the ongoing procurement expenditure limitation is needed. Calculating the “headroom” available under the procurement expenditure limit over the other time periods suggested would be too late to prevent the very result the statute seeks to prevent: incurrence of too high RPS costs. Only annual calculations would ensure avoidance of excessive RPS costs and disproportionate rate impacts. Non-annual time periods are simply too infrequent to ensure compliance with the requirement that the cost limitation prevent disproportionate rate impacts.

16. Do you agree with the Staff’s proposal that the 10-year PEL methodology should forecast an increase in IOUs' total revenue requirements annually by 2.75%? Explain why or why not. If some other escalation rate should be used, explain why the proposed rate is preferred.

No, but not because the 2.75% is the “wrong” forecast increase (although there is no basis for it); the larger issue is that the IOU’s total revenue requirement should not serve as the denominator.

17. Section 399.15(c)(1) provides that, in establishing the procurement expenditure limitation, the Commission shall rely on, among other things, “the most recent renewable energy procurement plan.”

- Identify specific information that the Commission should request that IOUs provide in an annual RPS procurement plan to provide information for the PEL methodology. Please specify the element(s) of Sections 399.15(c)-(f) to which the identified information is relevant.
- For each item, please identify whether the information would be completely available publicly. If, in the opinion of the commenter, it would not be, please:

[31] PU Code §399.15(g)(2)(A).

- State why the information would not be completely publicly available, with appropriate legal citations if relevant;
- Propose a method for increasing the public availability of the information within any legal constraints identified.

The vast majority of this information should be public. We understand the Commission is endeavoring to increase the transparency of RPS cost information, and strongly encourage this effort.

18. Do you agree with Staff's proposal that the IOUs should update inputs and assumptions at each key decision point along the procurement continuum? (See Attachment C.) Explain why or why not.

Generally, yes.

19. Do you agree with Staff's proposal for the PEL to be recalculated every two years? Why or why not? What other, time period would be preferable?

No, because if recalculated every two years using the Staff Proposal, the Procurement Expenditure Limitations would not serve to prevent disproportionate rate impacts; they should be calculated every year and impact the following year's procurement.

20. What process should be used to recalculate the PEL every two years? If a different time period should be used, should a different process be used, as well. Please explain any differences.

They should be recalculated every year.

21. The IOUs utilize a standardized method to determine the net market value (NMV) of an RPS procurement contract using least-cost, best-fit criteria, as required by Section 399.13(a)(4)(A). 35 The NMV quantifies key direct and indirect cost factors and ensures that an IOU's RPS procurement decisions are based on the expected value of the procurement, rather than simply the identification of the contract with the lowest cost. The statutory limit on RPS procurement expenditures set by Section 399.15(c) does not interfere with or override the requirement for an IOU to select contracts based on NMV. However, a situation might occur in which an IOU would have to decide between a higher valued contract and a lower valued contract if the marginal higher valued contract may cause the IOU to exceed its PEL.

- What factors should guide an IOU's shortlisting decision in the situation described above?
- What factors should guide an IOU's contract execution decision in the situation described above?
- What factors should guide the Commission's review of an IOU's request for contract approval in the situation described above?

Ensuring the prevention of disproportionate rate impacts is not discretionary; the Legislature's use of the directive, "shall", in lieu of the permissive, "may" means that the Commission must set the limitations at a level that prevents disproportionate rate impacts. Section 399.15(d) states, "the Commission *shall ensure* that … the *limitation is set at a level that prevents disproportionate rate impacts*." Required compliance with the law should thus be the "factor" guiding the Commission's and the utility's actions in this regard. The mandate that disproportionate rate impacts must be prevented should take precedence.

22. How, if at all, should the PEL methodology take account of new or emerging technologies or procurement requirements? (e.g., IOUs' investments in storage connected to distribution systems; or procurement necessary for local capacity requirements (see D.13-02-015).)

Storage is not on the list of excluded costs, so the costs of storage associated with incremental RPS procurement (e.g., solar or wind plus a battery) should be included.

23. Should the PEL include a portfolio cost minimization strategy/framework? How would such a strategy be implemented as part of the PEL?

No response at this time.

24. What is the role of "portfolio optimization" in implementing the PEL?

No response at this time.

25. Please identify any information necessary to provide the appropriate inputs for the PEL calculation, as it is described in the Staff Proposal. Please specify where each type of information may be found, and whether it is currently in public

or in confidential form. If the information is kept confidential, please identify any publicly available information that would be a satisfactory approximation, for purposes of the PEL. Please explain why the publicly available approximation would be appropriate.

No response at this time.

26. 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 may 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 long-term procurement plan established for the electrical corporation pursuant to Section 454.5.

- What criteria should the Commission use to determine that an IOU's PEL will be insufficient to support the projected cost of meeting the IOU's RPS procurement obligations? Please consider at least the following:
  - At what point in time should the determination be made?
  - For what time period into the future should the determination apply?
  - Taking into account forecasting error and other uncertainties in the RPS procurement process, what quantitative elements should be required in an IOU's showing?

No response at this time.

- To whom and by what process should the showing be made? Staff proposes the Tier 3 advice letter process. Please comment on the appropriateness and effectiveness of that proposal.
- Should another process be used? Examples could be:
  - Showing made to, and decision made by, the Director of Energy Division;
  - Showing made by Tier 1 or Tier 2 advice letter;
  - Showing made by formal motion in the existing RPS proceeding;
  - Some other method. Please explain your choice.

The Commission should consider setting the procurement expenditure limitations in a decision, and then the petition for modification process would be available. There may be insufficient process associated with Tier Three Advice Letter to fully develop a record to support a changed expenditure limitation.

27. How should the Commission interpret "a de minimis increase in rates?"

Section 399.12.(h)(3)(A) sets a "de minimis" quantity at 2% for purposes of the amount of non-renewable fuel that an eligible RPS resource can use when creating a REC.[32] This statutory definition of de minimis for REC purposes should guide the Commission's setting of definition of de minimis for rate impact purposes. Large Users recommend that the Commission find that any increase greater than a 2% increase in the forecast incremental RPS generation revenue requirement would lead to a greater than de minimis rate impact.

28. Section 399.15(b)(3) provides that "a retail seller may voluntarily increase its procurement of eligible renewable energy resources beyond the renewables portfolio standard procurement requirements."

- How, if at all, should such voluntary increases in RPS procurement be accounted for in the PEL methodology?

This sentence has been deleted by AB 327 (Perea); although it has yet to be signed by Governor Brown, AB 327 is likely to be signed soon.

- Should voluntary RPS procurement be allowed if it would cause an IOU to exceed its PEL?

No.

- Should voluntary procurement be allowed if it would cause an IOU to come close to exceeding its PEL?

No.

- Should the Commission interpret Section 399.15(f) as not allowing an IOU to undertake voluntary procurement that would exceed its PEL expenditure limitation?

Yes.

[32] PU Code §399.12.(h)(3)(A) provides: "Electricity generated by an eligible renewable energy resource attributable to the use of nonrenewable fuels beyond a de minimis quantity used to generate electricity in the same process through which the facility converts renewable fuel to electricity, shall not result in the creation of a renewable energy credit. The Energy Commission shall set the de minimis quantity of nonrenewables fuels for each renewable energy technology at a level of no more than 2% of the total quantity of fuel used by the technology to generate electricity"

29. No response provided.

IV. CONCLUSION

For RPS cost containment to prevent disproportionate rate impacts, the "cure" of not signing further contracts or not building additional utility-owned resources or otherwise procuring RPS energy must be viable. The Staff Proposal offers no such viable cure; it should be modified to avoid excessive RPS costs and disproportionate rate impacts. The rolling, 10-year average period should instead be a 12-month fixed annual limitation, with annual updates. The PEL calculation should not compare forecast RPS costs to the total utility revenue requirement; rather, a comparison of incremental forecast RPS costs to historical, actual RPS costs, as proposed by Large Users, would better determine proportionality of impact.

Respectfully submitted,

/S/
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Counsel to the
California Large Energy Consumers
Association and the Energy Producers and
Users Coalition

September 26, 2013 (REFILED AND RESERVED 10/11/2013 WITH REVISED TITLE)

VERIFICATION

I am the attorney for the California Large Energy Consumers Association in this matter. CLECA is absent from the City and County of San Francisco, where my office is located, and under Rule 1.11(d) of the Commission's Rules of Practice and Procedure, I am submitting this verification on behalf of CLECA for that reason. I have prepared and read the attached "**ALTERNATE PROPOSAL OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, THE ENERGY PRODUCERS AND USERS COALITION, AND THE CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION TO THE STAFF PROPOSAL FOR A METHODOLOGY TO IMPLEMENT PROCUREMENT EXPENDITURE LIMITATIONS FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM**," dated September 26, 2013 and reserved on October 11, 2013 with a new title. I am informed and believe that the matters stated in this document are true.

I declare under penalty of perjury that the forgoing is true and correct.

Executed on October 11, 2013 at San Francisco, California.

Nora Sheriff

Nora Sheriff
Counsel to the
California Large Energy Consumers Association

VERIFICATION

I am an attorney for the Energy Producers and Users Coalition (EPUC) in this matter. EPUC is absent from the City and County of San Francisco, where my office is located, and under Rule 1.11(d) of the Commission's Rules of Practice and Procedure, I am submitting this verification on behalf of EPUC for that reason. I have read the attached "**ALTERNATE PROPOSAL OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, THE ENERGY PRODUCERS AND USERS COALITION, AND THE CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION TO THE STAFF PROPOSAL FOR A METHODOLOGY TO IMPLEMENT PROCUREMENT EXPENDITURE LIMITATIONS FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM**" dated September 26, 2013 and reserved on October 11, 2013 with a new title.. I am informed and believe, and on those grounds allege, that the matters stated in this document are true.

I declare under penalty of perjury that the forgoing is true and correct.

Executed on October 11, 2013.

Nora Sheriff

Nora Sheriff
Counsel to the
Energy Producers and Users Coalition

VERIFICATION

I am the Senior Vice President for the California Manufacturers and Technology Association. Under Rule 1.11 of the Commission's Rules of Practice and Procedure, I am submitting this verification on behalf of CMTA. I have read the attached "**COMMENTS OF THE CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, THE ENERGY PRODUCERS AND USERS COALITION, AND THE CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION ON THE STAFF PROPOSAL FOR A METHODOLOGY TO IMPLEMENT PROCUREMENT EXPENDITURE LIMITATIONS FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM**," dated September 26, 2012. I am informed and believe, and on those grounds allege, that the matters stated in this document are true.

I declare under penalty of perjury that the forgoing is true and correct.

Executed on September 26, 2013 at Sacramento, CA.

/s/

____

Dorothy Rothrock
Sr. VP, Government Relations
California Manufacturers and
Technology Association