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)

OPENING COMMENTS
OF THE DIVISION OF RATEPAYER ADVOCATES IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S SIMON'S RULING REQUIRESTING COMMENTS ON PROCUREMENT EXPENDITURE LIMITATIONS FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM

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I. INTRODUCTION AND BACKGROUND

The Division of Ratepayer Advocates (DRA) offers the following comments in response to the January 24, 2012 Ruling requesting input on the procurement expenditure limitations for the Renewables Portfolio Standard (RPS).

DRA recommends that the Commission consider a "bill impact" approach to establish the cost limitation for each utility. Senate Bill 2(1x) clearly instructs the Commission to ensure that the limitation is "set at a level that prevents disproportionate rate impacts."[1] DRA proposes that the Commission "prevent[] disproportionate rate impacts" through adoption of a mechanism that uses bill impacts as the measure of "disproportionate rate impacts." The reason to differentiate between bill and rate impacts, although they are related, is to assure that the cost limitation is as understandable as possible to the ratepayers who will foot the bill for California's RPS program.

DRA recommends that the Commission include as many of the costs of renewables within this recommendation as is practical and compliant with the restrictions in Senate Bill 2(1x). DRA's purpose is not to advocate for an untenable cost limitation, but to include all of the renewable costs and design a limitation that ensures the success of the 33% Standard. Inclusion of all of the renewable costs is crucial to allow the Commission, stakeholders, and the public, to fairly assess the 33% policy and implement the policy with the public interest in mind.

II. DISCUSSION

DRA addresses the Judge's questions in the order asked, below:

1. Section 399.15(c) provides that a procurement expenditure limitation must be established "for each electrical corporation." How should the procurement expenditure limitation methodology reflect this instruction?
- Should the methodology be the same for all IOUs in all respects?
- Should the inputs to the methodology be specific to each IOU?
- Should both the methodology and the inputs be IOU-specific?
- Should some other relationship between methodology and IOU be established? Please specify and explain any proposal.

DRA recommends that the Commission adopt a cost limitation that is based on a predetermined bill impact. That bill impact limitation can be set to either a dollar amount or a percentage. A dollar limitation – for example a maximum of one dollar per customer-month –

[1] Section 399.15(d)(3).

would be much easier to calculate. Regardless of how the cost limitation is calculated, a uniform methodology across all IOUS appears to be the most equitable and expedient approach. While there may be arguments to adopt utility-specific methodologies, such arguments would need to explain why such an approach is fair, and justify the additional burden inherent in implementation of more than one methodology.

If the Commission adopts DRA's recommended bill impact approach, the question of inputs into the methodology will be moot, since the approved bill impact will be a firm dollar or percentage limitation. Should the Commission choose a different approach, DRA recommends that there be as much consistency as possible among the utilities. Therefore, each variable should be fixed for each utility, although the number itself would likely need to vary.

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

- Please identify the types of procurement that should be included in this requirement and identify any special rules or methods that may be required to account for the costs. Please consider at a minimum the following situations:

- Procurement from RPS-eligible qualifying facilities under the federal Public Utility Regulatory Policies Act of 1978 (Public law 95-617);

- Procurement pursuant to the renewable auction mechanism established by D.10-12-048;

- Procurement pursuant to the feed-in tariff program established by SB 32 (Negrete McLeod), Stats. 2009, ch. 328;

- Procurement from bilaterally negotiated contracts, not part of a utility solicitation for RPS-eligible generation resources;

- Procurement by means of utility-owned generation.

DRA recommends that the Commission include the cost of all methods of procurement of RPS-eligible energy within the expenditure limitation. These methods of procurement include but are not limited to: RPS-eligible Qualifying Facilities (QFs) pursuant to Public Utility Regulatory Policy Act (PURPA), the Renewable Auction Mechanism (RAM), Feed-in Tariff (FIT), bilaterally negotiated contracts, contracts arising from solicitations, utility-owned generation (UOG), the Solar Photovoltaic Program (SPVP), and any RPS-eligible energy the utilities purchase from customer-side programs under Net Surplus Compensation (NSC) or other mechanisms. Whenever the utilities purchase or generate a Renewable Energy Credit (REC), those costs are eligible to be included under the RPS expenditure limitation. In addition, expenditures closely associated with the purchase of RECs, such as firming and shaping agreements required for REC-only products to qualify for RPS Product Content Category 2, should also be accounted for under the expenditure limitation. All of these costs are eligible to be counted per Section 399.15(c)(2) and 399.15(d)(2).

Currently, ratepayers also fund customer-side programs such as the California Solar Initiative (CSI), Emerging Renewables Program (ERP), Self-Generation Incentive Program (SGIP), and New Solar Homes Partnership (NSHP); these programs subsidize the direct costs of procurement for distributed renewable energy generation. RECs created by customers under such programs may in the future be sold to the utilities for the purpose of fulfilling RPS Category 3 requirements or other Categories. Arguably, the cost of such REC procurement involves not only the direct cost paid to obtain the REC, but also a portion of the program funds used to procure the associated generation. If in the future the California Energy Commission (CEC) determines that the associated generation is RPS-eligible, the cost of these programs should count toward the limitation.

- *Please identify all "costs" that are implicated by this requirement, taking into account those costs that are excluded by Section 399.15(d)(3).*

"Costs" that should be included in calculating the cost limitation should take into account not only the direct price paid by ratepayers for Power Purchase Agreements (PPAs) and utility-owned generation, but also costs incurred to support such generation. Per Section 399.15(c)(2), these incurred costs – excluding those mentioned in Section 399.15(d)(3) – include, but are not limited to: RPS and related program administrative costs, distribution upgrades, integration costs, Resource Adequacy (RA) replacement value,[2] and possibly the construction of new transmission infrastructure. The cost limitation should be comprised of all expenditures needed to support and administer the RPS program, or to deliver the electricity onto the grid while maintaining reliability.

DRA requests that the Commission clarify the meaning of "transmission upgrades" in Section 399.15(d)(3), and whether "transmission upgrades" refers only to upgrades to existing transmission, or also the construction of new transmission infrastructure. DRA proposes that it is reasonable to include the construction of new transmission infrastructure as a "cost," as those

[2] For RPS contracts which are not found to be RA-adequate.

costs must be incurred in order to convey the electricity onto the grid. The building of new transmission is a substantial cost that is currently driven primarily by renewable development and, as such, deserves to be included in the RPS cost limitation. Finally, upgrades to the distribution portion of the grid should be included.

- Should the statutory characterization of "the costs of all procurement credited toward achieving the renewables portfolio standard" be interpreted as including:

- Estimates, made at the time a procurement contract is approved by the Commission, of the costs that will be incurred over a period of time.

- should the period of time be the entire period of the contract?

- should it be some other time period? Please describe and justify the choice of another period; or

- A record of actual expenditures by the utility for the procurement contract over a period of time.

- should the period of time be the entire period of the contract?

- should it be some other time period? Please describe and justify the choice of another period.

- how should the actual expenditures be determined?

Regardless of how the Commission calculates the cost limitation, DRA recommends enforcement of the cost limitation through use of the forecasts of RPS expenditures, followed by a "true up" with records of actual expenditures. Specifically, per 399.15(c)(2), an estimate of the cost for the period of the contract up to 2020 should be initially used to aid the utility in planning its RPS-eligible procurement expenditures. These estimates should be prepared annually and reconciled with actual expenditures as they are incurred. The reconciliation could occur in the following years' filing or after the end of the relevant compliance period. The cost limitation should apply to expenditures incurred from January 2011 to December 2020. The actual expenditures should be determined via the methodology and types of expenses decided upon in response to the first portion of this question.

However, the methodology is determined, Section 399.15(d)(2) requires that the Commission include costs of all RPS-credited procurement and that the Commission set the cost limitation at a level that prevents disproportionate rate impacts as required by Section 399.15(d)(1). Also, Section 399.15(e)(1) allows the Commission to revise the cost limitation downward as well as upward, consistent with the criteria under Sections 399.15(c) and 399.15(d).

- *How should RPS procurement costs incurred prior to the implementation of the procurement expenditure limitation required by SB 2 (1X) be addressed in the procurement expenditure limitation methodology?*

The Commission should include all RPS procurement costs incurred during the period governed by SB 2(1x), from 2011 to 2020, in setting the procurement expenditure limitation. Doing so would provide a full picture of the costs associated with achieving the 33% RPS goal and would more accurately inform efforts of the Commission to establish an appropriate cost limitation.

- *How should the costs of procurement from utility-owned generation be addressed in the procurement expenditure limitation methodology? Please discuss any issues not addressed in response to other questions.*

Utility-owned generation (UOG) should be treated under the same rules as other types of procurement for the purposes of the renewable cost limitation mechanism. The only complication would be that UOG investments are typically included within a utility's rate base and earn a rate of return. As part of UOG filings, utilities calculate the ratepayer cost for each year of the facility. The ratepayers' costs for the years 2011 through 2020 of utility-owned facilities should be included within the cost limitation.

3. Should the procurement expenditure limitation methodology provide a single limitation for the time period 2011-2020?

DRA recommends that the cost limitation be set for the entirety of the 33% RPS program, January 2011 through December 2020. However, the Commission should establish check-points so that it can monitor whether utilities are projected to remain within the cost limitation, and if necessary, increase the cost limitation pursuant to Section 399.15(e)(1). These check-points should require that the utilities demonstrate and forecast compliance with the cost limitation after the end of each compliance period. That showing can be included with the demonstration of compliance with the portfolio content categories that DRA expects that the Commission will require at the end of each compliance period. If the Commission believes that the demonstration of compliance with the cost limitation – and projection of compliance through 2020 – should be submitted more frequently, DRA would not oppose an annual filing.

The reasoning behind a total cost cap, however, is to account for all of the RPS and all eligible RPS-related costs associated with achievement of the 33% mandate. Establishment of a cost cap for each compliance period may incent utilities to hold off on procurement until the beginning of the next compliance period, for example, if the utility is close to its limitation. There are already a number of constraints the utilities face that create a jumble of incentives. For example, utilities have an incentive to not over procure in one period due to limitations on banking, but also have an incentive to over procure to avoid penalties.

DRA proposes that the cost limitation send as consistent and clear a message as possible. Creation of just one number to be achieved for the entirety of the 33% program seems the most administratively simple method, as long as oversight is strong and relatively frequent between now and 2020.

4. Should the procurement expenditure limitation methodology provide a limitation for a different time period or set of time periods?
- Annual.
- Each compliance period through 2020 (i.e. 2011-2013; 2014-2016; 2017-2020).
- The period 2011-2015 and the period 2016-2020.
- The year 2020.
- The entire time an RPS procurement obligation has been in place (i.e., beginning in 2003).
- Some other time period. Please specify and explain the reasons for the time period proposed.

As explained in response to Question 3, DRA recommends calculation of a single limitation through the year 2020. As for which period the limitation should apply to in total, DRA recommends the duration of the 33% program, from 2011 to 2020. Again, this appears to be the most administratively simple way to implement the cost limitation. Although it would be informative to evaluate all RPS expenditures from the beginning of the first RPS requirement in 2003, such a calculation is likely to be administratively infeasible, especially if costs other than contract payments are considered. Integration, distribution upgrades, and other costs might make the already difficult exercise unnecessarily laborious.

Since the program itself runs from the beginning of Compliance Period 1 in 2011 to the end of 2020, DRA recommends that also be the time span of the cost limitation mechanism.

5. Since RPS procurement obligations continue indefinitely, how should the procurement expenditure limitation methodology treat RPS procurement in the years after 2020?

Assuming there will be no new policies affecting RPS procurement, DRA recommends initiating a new proceeding for compliance years 2021 onward to determine procurement expenditure limitation methodology. Current policy dictates three compliance periods from 2011 to 2020, while RPS compliance from 2021 will be annual.

6. 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."

- What elements of an IOU's RPS procurement plan should be used in establishing the procurement expenditure limitation methodology?

- Should the methodology include a mechanism for updating the limitation with information from the IOU's most recent RPS procurement plan?

- Should the methodology use information from the most recent RPS procurement plan available at the time the Commission adopts the methodology, but not provide for periodic updates from more recent RPS procurement plans?

DRA recommends that, in order to establish the procurement expenditure limitation, the Commission first determine an acceptable bill impact, either as a total dollar increase or percentage bill increase to be experienced by the average customer. Implementation of a percentage limitation on bill impact is likely to be more complex. However, a limitation of, for example, one dollar per customer-month from 2011 to 2020 is a relatively straightforward number that would not be difficult to calculate. Specifying an allowable dollar increase per customer month also has the advantage of being easy to understand for the public and policymakers.

The utilities' RPS procurement plans would contribute to this calculation by providing a check to assure that the adopted cost limitation is reasonable. DRA recommends that the cost limitation – for example a dollar per customer-month – be compared against the utilities' 2011 procurement plans as well as forecasts of procurement needed to reach 33%. The parties should then vet whether the proposed limitation is realistic for the utilities to achieve and also meaningful as a protection for ratepayers.

Updating the limitation with every annual procurement plan seems both burdensome and unnecessary, since the Commission has the opportunity to increase the spending cap per Section 399.15(e)(1). Automatic adjustment of the cap every year will make the market even more volatile and provide ratepayers less meaningful protection against rate shock. If the Commission follows DRA's recommendation to establish the limitation for the entirety of the program's timeline, 2011 to 2020, the lengthy timeframe for measuring compliance would help hedge against price spikes.

If another set of RPS procurement plans are adopted before the cost limitation is implemented, DRA is not opposed to including that information if it is practical. However, the procurement plans only serve as a "reality check" of the cost limitation in this model so it may simply be unnecessary to account for the likely insubstantial differences between them. Since most RPS contracts needed to achieve the 33% RPS have already been executed, DRA expects that future RPS procurement plans will not be nearly as substantial as the ones in the last several years. Subsequently, the changes among them from year to year will unlikely substantially impact the cost containment numbers.

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

- What sources of data should be used to develop this approximation? Please provide specific examples.

The investor-owned utilities do not currently own and operate major renewable projects but they do own and operate smaller facilities, for example under SPVP. These data could be used and the utilities could also develop a proxy for the estimation of the costs of ownership of major renewable facilities.

For market data, the Commission could turn to aggregated data from confidential approved PPAs. In addition, there are several studies in the area including: National Renewable Energy Laboratory's "Cost and Performance Assumptions for Modeling Electricity Generation Technologies," the CEC's "Comparative Costs of California Central Station Electricity Generation," and Public Interest Energy Research's "Renewable Cost of Generation Update."

- *Should the methodology differentiate between utility-owned RPS-eligible generation and RPS-eligible generation owned by independent power producers? If so, what information or parameters should differ between the two types?*

DRA recommends that in principle, the methodology for evaluating utility-owned RPS-eligible generation and RPS-eligible generation owned by independent power producers should be the same. Ratepayers should be indifferent to the source of RPS-eligible procured electricity.

- *Should only publicly available data be used to develop this approximation? Please identify and explain any limitations of publicly available data for this purpose.*

Once confidential data is sufficiently aggregated, it ceases to be confidential.[3] DRA recommends the Commission aggregate the necessary confidential data until it can be made public and then work with these data. Obscuring the actual numbers will make it harder for parties to participate in the development of this cost limitation methodology. In the past the public at least had access to one piece of information about a contract: whether it was above the Market-Price Referent (MPR). With the implementation of the 33% RPS, it appears that the public will not even have a similar piece of information available.

8. Section 399.15(c)(3) provides that, in establishing the procurement expenditure limitation, the Commission shall rely on, among other things, "the potential that some planned resource additions may be delayed or canceled." How should the methodology take such potential into account?

> *- How should the methodology define a "delay"? A "cancellation"? Please discuss usual commercial practice and provide examples in support of the proposed definition. Please provide examples of how a delay could be distinguished from a cancellation for purposes of the procurement expenditure methodology.*
>
> *- Should delays in the progress of contracted-for RPS resources be treated differently from cancellations?*
>
> *- Should the methodology use data on the historical record of delays/cancellation of RPS procurement contracts for each IOU?*
>
> *- Should the methodology use each IOU's projections of likely delays/cancellations in the future?*
>
> *- Should the methodology create projections of delays/cancellations of contracted-for RPS generation projects in some other way? Please describe the proposal in detail.*
>
> *- How should the potential for delays/cancellations, however determined, be used in the procurement expenditure limitation methodology?*

The Commission has a number of years of data on delays and cancellations available to it that should help develop a reasonable set of assumptions to inform the cost containment methodology. Although the renewable market is maturing and changing, historical data can still be used to develop these assumptions.

As far as a definition of delay is concerned, utilities have had to designate projects as being "Under Development – on schedule" or "Under Development – delayed" in their biannual

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[3] See the Commission's Q4 2011 RPS Report to the Legislature at http://www.cpuc.ca.gov/NR/rdonlyres/3B3FE98B-D833-428A-B606-47C9B64B7A89/0/Q4RPSReporttotheLegislatureFINAL3.pdf

Project Development Status Reports (PDSRs) for years.[4] The definition of "delay" in that context has revolved around the project meeting its contractual Guaranteed Commercial Operations Date (GCOD). A project that comes online after its GCOD should be defined as "delayed".

Failure is harder to define because the utilities frequently wait for long periods before classifying a project as officially "terminated." Certainly, projects that have been terminated can be classified as failures. In addition, DRA recommends the Commission select a specific amount of time after GCOD that projects can be considered failures for the sake of this methodology. One potential amount of time is six months, the period that a Renewable Auction Mechanism (RAM) contract can receive as an extension after failing to meet its COD.[5] RAM projects are standard contracts between utilities and facilities 20 megawatts in size or smaller. Although an imperfect analogy to the entirety of RPS projects in utility portfolios, the Commission's guidelines for RAM projects provide a good example of definitive failure. In RAM, if a facility fails to meet its COD plus the 6-month extension, the contract is terminated.[6] For the purposes of the cost limitation methodology, if a contract fails to come online six months after its GCOD, it should be considered a failure.

Although reliance on historical patterns of failures and delays is an imperfect method in a fast-moving market, DRA recommends the Commission consider reliance on historical data as the most administratively simple. DRA may not be opposed to use of utility projections of delays/cancellations instead, but at the moment each utility employs a different and highly subjective methodology to forecast delays/cancellations. If the Commission were to employ utility projections rather than historical data, the forecasting methodology would have to be standardized first, including removing the subjective element as much as possible. Instead, the Commission could choose a reasonable period of the past – for example the last six years, since

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[4] The utilities are required to file PDSRs with the Energy Division, along with RPS Compliance Reports, every year on March 1 and August 1.

[5] D.10-12-048, p. 52, Finding of Fact 32, p. 84; Conclusion of Law 31, p. 90.

[6] D.10-12-048, p. 52, Finding of Fact 32, p. 84; Conclusion of Law 31, p. 90.

the legislative acceleration of the RPS requirement.[7] The Commission could then relatively easily assess the rates of failure and delay, using the definitions above.

The resulting rate of failure and delay – which DRA proposes be standard among the utilities rather than separately calculated for each utility – can feed into the procurement expenditure limitation when the Commission evaluates the reasonableness of a proposed bill impact limitation. The Commission will use utilities' procurement forecasts, adjusted for the determined rate of failures and delays – to determine if the 33% Standard can be met under a proposed bill impact limitation.

Another use for the calculated rates of delays and failures can be to determine the margin of over procurement addressed in the answer to Question 11 below. DRA emphasizes, however, that the Commission must not account for delays/failures twice.

9. Taking into account your responses to questions 3-8, above, how often should the procurement expenditure limitation be calculated for the years through 2020, using the methodology and inputs that the Commission will adopt?

- Annually.

- At the beginning of each compliance period (i.e. 2011-2013; 2014-2016; 2017-2020).

- Once for the period 2011-2015 and once for the period 2016-2020.

- Once for the period 2011-2020.

- Once for the year 2020.

- Once for the entire time an RPS procurement obligation has been in place (i.e., beginning in 2003).

- Some other time period. Please specify and explain the reasons for the time period proposed.

As stated in previous answers, DRA proposes that the limitation be set once, for the entire period from 2011 to 2020. DRA also recommends that, at the end of each compliance period, the utilities demonstrate through a compliance filing that they are on track to remain within the cost limitation. This showing would be filed as part of the demonstration of compliance with procurement content categories that should also be filed at the end of each compliance period. In DRA's *Opening Comments Of The Division Of Ratepayer Advocates In Response To Administrative Law Judge's Simon's Ruling Requesting Supplemental Comments On Reporting And Compliance Requirements For The Renewables Portfolio Standard Program*,

[7] See SB 107 (Simitian, 2006).

filed on February 10, 2012, DRA outlined its vision that this filing occur in conjunction with the March 1 Compliance Filing immediately following the end of a Compliance Period.

10. How often should the procurement expenditure limitation be calculated for the years after 2020, using the methodology and inputs that the Commission will adopt?

It is likely that a new law will govern RPS by the year 2021. If such a law is not adopted, DRA recommended in its answer to Question 5 above, that the Commission open a new proceeding to discuss a post-2020 RPS program. If such a proceeding is not opened, DRA recommends that the instant proceeding determine that the cost limitation be calculated annually after 2020. As it currently stands, the legislation adopts a 33% RPS for each year after 2020. Since the program will become an essentially annual program under that framework, the most reasonable cost limitation would be annual as well.

11. Section 399.13(a)(4)(D) requires the Commission to adopt "[a]n appropriate minimum margin of procurement above the minimum procurement level necessary to comply with the renewables portfolio standard to mitigate the risk that renewable projects planned or under contract are delayed or canceled."

- How should such a margin of above-minimum procurement be addressed in the procurement expenditure limitation methodology?

- How should the methodology treat the interaction of the margin of above-minimum procurement and the potential for delays and/or cancellations?

DRA recommends that the Commission *either* adjust the cost limitation based on the expected rate of failures and delays as described in Question 8 above *or* adopt a minimum margin of procurement to mitigate the risk of such failures and delays. Doing both is clearly redundant. If the Commission adopts the minimum margin of over-procurement, DRA recommends the calculation method for risk of failure and delay that DRA describes in its answer to Question 8.

In terms of the treatment of the margin for purposes of planning for these delays/cancellations, it should be noted that the utilities already apply assumed failure rates to their procurement expectations and procure accordingly. It appears that the utilities de-rate the portion of their portfolio that is in development by a particular failure rate – some do it on a per-contract basis and others on a whole-portfolio basis. If that rate is, for example, 30%, then the utility "downgrades" the number of RPS-compliant gigawatt-hours currently in development in its portfolio by 30%. This downgrade creates a need for a certain additional amount of gigawatt-hours which the utility then procures. The system is imperfect since one could argue that thirty percent of the subsequent procurement should be subject to the assumed failure rate, but it seems relatively straightforward and effective

12. Section 399.13(a)(4)(A) requires the Commission to adopt "criteria for the rank ordering and selection of least-cost and best-fit eligible renewable energy resources…on a total cost basis…," taking various factors into account.

- Should the procurement expenditure limitation methodology incorporate the "total cost basis" factors set out in Section 399.13(a)(4)(A). If so, how?

- Should the procurement expenditure limitation methodology be used as the criterion of "least-cost" for the least-cost best-fit determination? If so, how?

The procurement expenditure limitation should certainly, at minimum, incorporate the quantitative factors set out in Section 399.13(a)(4)(A). These include:

- "Estimates of indirect costs associated with needed transmission investments and ongoing electrical corporation expenses resulting from integrating and operating eligible renewable energy resources", and
- "The cost impact of procuring the eligible renewable energy resources on the electrical corporation's electricity portfolio."

Estimation of the transmission investments and integration costs to bring the eligible renewable resources online is possible, and both this Commission and the California Independent System Operator have completed such estimates.[8] It should be noted that integration costs should be interpreted broadly to include not only the costs of purchasing back-stop generation but also the cost of conventional facilities purchased primarily for integration with renewables as well as costs of energy storage procured for that purpose. DRA interprets the second bullet point to be the straightforward cost impact of contract payments or other direct costs of RPS facilities. These are already clearly included in the cost limitation mechanism.

DRA supports integration of the "least-cost best-fit" (LCBF) methodology with the procurement limitation, and DRA would wholeheartedly support the use of the limitation as the "least cost" portion of the LCBF methodology if the utilities or the Commission could demonstrate that it is possible. There are important adders currently in the LCBF methodology – such as adders for replacement Resource Adequacy value and transmission costs, among others –

[8] See the CPUC's "33% Renewables Portfolio Standard Implementation Analysis Preliminary Results" at http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf and the CAISO's "2011-2012 Transmission Plan" at http://www.caiso.com/Documents/Draft2011_2012TransmissionPlan.pdf.

that should not be removed. DRA recommends the inclusion of these adders in the cost limitation methodology, but if the Commission chooses not to do so, it should not delete them from the LCBF methodology.

DRA also notes that the utilities apply the LCBF methodology quite differently. There may be substantial benefit, to both intervenors and renewable market participants, with standardization of the LCBF among the utilities.

13. Should the procurement expenditure limitation methodology take into consideration the value of diversification of resources in IOUs' RPS procurement? Specifically,

- Should the methodology create a set of technology-specific expenditure limitations?

- Should the methodology create a set of geographically-defined expenditure limitations?

DRA believes the methodology should be technology and location-neutral, and create neither technology-specific expenditure limitations nor geographically-defined expenditure limitations. The renewable market is now robust and able to produce the most cost-competitive projects by virtue of its selection of the best technologies and locations. DRA does not believe that intervention into the market necessary as far as technologies and locations are concerned. In addition, such limitations, if poorly designed, could have the perverse effect of limiting technologies or generation in locations that are the most economically sound and provide the greatest value per dollar.

- Should the methodology give "extra credit" for diversification by technology?

- Should the methodology give "extra credit" for geographic diversification?

DRA strongly recommends that the Commission not give "extra credit" for either technological or geographic diversification. There are several reasons: the subsidy of specific technologies or areas like Competitive Renewable Energy Zones is beyond the scope of and inappropriate to address in this ruling, which covers the containment of the costs of the RPS program. California ratepayers already pay for a multitude of existing programs which promote technological and geographical diversity. Trends in the development of renewable energy, as well as efforts targeting the promotion of technological and geographical diversity, are currently underway.

DRA believes procurement expenditure limitations should be neutral for technology and geographic diversity, as Section 399.15 (c)-(g) does not specify special carve-outs for either.

Distortion of price signals with "extra credit" would inhibit the market's ability to select the most economically efficient RPS-eligible generation. In addition, carve-outs for technology and geographic diversity may violate Section 399.15(d)(3)'s requirement that procurement expenditures not include any indirect expenses. Technological and geographic diversity is already promoted by a host of existing programs and policies funded by California ratepayers. These programs include: the California Solar Initiative, Emerging Renewables Program, FIT, RAM, Small Generator Incentive Program, Net Energy Metering, Renewable Energy Transmission Initiative, Desert Renewable Energy Conservation Plan, and the State Bioenergy Goal.[9] Both individually and cumulatively, these programs create technological and geographical diversity.

The burden of proof lies on those who would argue that not only is "extra credit" necessary for further technological and geographical diversification, but also that the current proceeding is the proper venue to redress concerns that current, ratepayer funded programs and policies have been inadequate in contributing towards RPS-eligible procurement. If California is to serve as a laboratory for pre-commercialized technologies, these subsidies should only be underwritten by ratepayers if it can be demonstrated that such subsidies will capture proportionate benefits and not suffer "disproportionate rate impacts," per 399.15(d)(1).

Indirectly, data trends[10] confirm the effect these programs and policies have had in the promotion of technological and geographical diversity: from 2008 to 2010, California's share of energy from renewable sources has increased from 10.6% to 13.7%. Geothermal (4.6%), biomass (2.3%), and small hydro (1.7%) have traditionally been the dominant sources of renewable energy in California. However, geothermal, biomass and small hydro have only remained relatively steady over the past few years, while the amount of energy derived from wind has doubled to 4.7%. During this period, solar's portion of retail sales has remained at 0.3%, its absolute value has grown approximately 13% annually, from 746 GWh to 959 GWh. In addition, a large portion of the renewable projects that will come online in the next few years will be solar. Both as a share of California's total power sources and among renewables themselves, it is a fact that renewables are diversifying geographically and by technology.

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[9] See Executive Order S-06-06 at gov.ca.gov/index.php?/print-version/executive-order/183/

[10] California Energy Commission, QFER and SB 1305 Reporting Requirements. In-state generation is reported generation from units 1 MW and larger.

14. How should the procurement expenditure limitation be applied to the Commission's evaluation of individual RPS contracts?

- The methodology should include a way to calculate a benchmark limit on the price of RPS procurement contracts (in dollars per megawatt-hour of generation) of a particular duration and technology type.

- The methodology should include a way to consider an individual RPS procurement contract, on a total expected cost basis, as a fraction of some larger procurement expenditure limitation.

- The methodology should use some other way to consider an individual RPS procurement contract in the context of the procurement expenditure limitation. Please provide a detailed explanation.

- The methodology should not be applied to individual RPS procurement contracts at all.

DRA recommends that the utilities submit, with each contract, an estimation of the contract costs' effect on the utility's ability to meet its cost limitation. If the Commission agrees with the DRA that included costs should go back to the beginning of 2011, then some eligible costs have already been incurred. The utilities will also have a forecast – developed as part of this proceeding – of future costs as well as a forecast of necessary procurement. Therefore, it should be relatively simple to calculate whether an individual contract puts each utility at an advantage or disadvantage in regards to meeting its limitation. The method would be similar to having a benchmark per megawatt-hour cost but would account for the expenditures the utility has already incurred or committed to.

15. Should the procurement expenditure limitation methodology include a methodology by which Energy Division staff could "monitor the status of the cost limitation for each electrical corporation," as required by Section 399.15(g)(1)?

- What elements would be required in order to monitor the status of the cost limitation for each IOU?

- How often should the status of the cost limitation for each IOU be examined?

- Annually;

- Once per compliance period;

- Once before January 1, 2016;

- Once before January 1, 2016 and again before December 31, 2020;

- Once before December 31, 2020;

- At the discretion of the Director of Energy Division;

- Some other time interval.

Yes, as DRA explains in previous answers, Energy Division staff should at minimum receive a showing after each compliance period that the utilities are on track to meet their cost limitations. DRA would not oppose a more frequent showing. DRA recommends that the showing include details of costs already incurred, as well as a forecast, through 2020, of expected costs.

III. CONCLUSION

DRA recommends that the Commission adopt a procurement expenditure limitation that is consistent across utilities, and can be calculated and approved in a transparent and straightforward manner with use of aggregated data available to all parties. The expenditure limitation should include all of the costs associated with renewables so that the Commission and stakeholders have an accurate accounting of the total costs of achieving the 33% RPS mandate.

Respectfully submitted,

/s/ DIANA L. LEE

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February 16, 2012

VERIFICATION

I, Diana L. Lee, 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 **"OPENING COMMENTS OF THE DIVISION OF RATEPAYER ADVOCATES IN RESPONSE TO ADMINISTRATIVE LAW JUDGE'S SIMON'S RULING REQUIRESTING COMMENTS ON PROCUREMENT EXPENDITURE LIMITATIONS FOR THE RENEWABLES PORTFOLIO STANDARD PROGRAM"** filed on February 16, 2012.

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 are true and correct.

Executed on February 16, 2012 at San Francisco, California.

/s/ DIANA L. LEE
Diana L. Lee
Staff Counsel