STATE OF CALIFORNIA
ENERGY RESOURCES CONSERVATION
AND DEVELOPMENT COMMISSION

Implementation of Renewables Portfolio Standard Legislation (Public Utilities Code Sections 381, 383.5, 399.11 through 399.15, and 445; [SB 1038], [SB 1078])	))))	**Docket No. 03-RPS-1078 RPS Proceeding Staff Workshop on Eligibility Criteria**

COMMENTS OF THE CALIFORNIA WIND ENERGY ASSOCIATION FOR THE MARCH 25, 2003 STAFF WORKSHOP ON RPS ELIGIBILITY ISSUES

The California Wind Energy Association ("CalWEA") appreciates this opportunity to provide written responses to the questions presented for discussion at the March 25, 2003, Staff Workshop on Eligibility Issues.[1] These comments elaborate further on the comments made by CalWEA at the workshop.

I. Incremental Geothermal Issues

A. Introductory Comments

As staff is no doubt aware, the geothermal eligibility issue is critically important. The extent to which geothermal power can satisfy a retail seller's annual RPS obligation to increase its renewables procurements will determine whether or not SB 1078 promotes substantial new renewables development over the next few years or not.[2] We believe that the Legislature intended for SB 1078 to increase substantially the absolute amount of renewable generation in operation each year, beginning in 2003, regardless of location, owner or power purchasing entity, rather than merely to shift existing renewables from one portfolio to another.

[1] CalWEA members currently include 23 wind energy companies, including owners of existing projects, developers of new projects, two turbine manufacturers, and other vendors.

[2] We use "retail seller" to mean those retail sellers that are obligated to acquire renewables under SB 1078, namely, investor-owned utilities, electric service providers, and community choice aggregators.

CalWEA also, however, recognizes the importance of maintaining the existing base of renewables. CalWEA was the party most responsible for SB 1078 taking the form of a "net increase" renewables requirement, rather than a "new renewables" requirement.[3] We were therefore sympathetic to Calpine's objection that, under an earlier version of SB 1078, The Geysers geothermal facilities (other than those with QF contracts) were excluded altogether from eligibility.[4] So we worked with Calpine to carefully construct a legislative amendment to make The Geysers eligible, while preserving the intended market for new renewables: the amendment enabled Geysers power, if acquired by a retail seller, to qualify as an increase to that retail seller's baseline quantity of renewables, bringing it closer to its 20% renewables target. It also provided that production above The Geysers' total 2001 output level could count toward a retail seller's 1% annual "net increase" renewables procurement requirement.

Though the legislative language underwent some redrafting before the bill passed, and the relevant subsection – P.U. Code Section 399.12(a)(2) -- ended up referring to all geothermal resources rather than specifically to The Geysers, this is always how we interpreted the legislation, and believe that the Commission should interpret it this way also. We were surprised and dismayed that, in its October 17, 2002, comments before the CPUC, Calpine chose to advocate that the relevant subsection of the bill had no meaning, because, it argued, The Geysers are eligible under the previous subsection (P.U. Code Section 399.12(a)(1)), which makes eligible a facility that meets the definition of "in-state renewable electricity generation technology" in Section 383.5.

The threshold decision for the Commission to make, therefore, is: does P.U. Code Section 399.12(a)(2) have any meaning at all, given that section (a)(1) could be read to make <u>all</u> existing geothermal resources that were not in a retail seller's 2001 portfolio eligible to satisfy a retail seller's 1% annual-increase obligation? We believe that the clear language of Section 399.12(a)(2) was included in the legislation for a reason, and that reason was to ensure that The Geysers power, which was not at the time in the portfolio of a retail seller, does not "soak up" the

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[3] Under the "net increase" requirement, a retail seller is required to "increase its <u>total</u> procurement of eligible renewable energy resources by at least an additional 1 percent … per year" (PUC Sec 399.15 (b)(1). This formulation requires the retailer to make up any declines in its baseline quantity of renewables <u>and</u> procure 1% in addition.

[4] One of the reasons that The Geysers resource was initially excluded from eligibility is that Calpine documents described its newly acquired 880-MW Geysers geothermal system as "very profitable." <u>Calpine: 1999 Annual Report</u>, March 1, 2000, letter from Peter Cartwright to Calpine stockholders, p. 1.

market intended largely for new renewable resources.[5] If the paragraph is relevant, the vast majority of Geysers acquisitions would count toward a retailer's baseline. The question remaining would then be: Under what circumstances should some fraction of The Geysers' output qualify as " incremental" and therefore be eligible to count toward a retail seller's 1% annual-increase requirement? If the paragraph is not relevant, then the issue of " incremental geothermal production" is also not relevant, as all geothermal output added to a retailer's portfolio would qualify toward a retail seller's 1% annual-increase requirement.

We urge the Commission to find that the paragraph (Section 399.12(a)(2)) is relevant, and to interpret it under the principle that geothermal resources should be treated as consistently as possible with how most other existing renewables are treated, unless the statute clearly provides otherwise. Specifically,

- Output from a geothermal facility that was sold to a retail seller in 2001 is included in that retail seller's renewables baseline. When that facility stops selling its output to that retail seller, that output should become generally eligible under the RPS – i.e., it should be eligible to satisfy a retail seller's 1% "net-increase" obligation (filling a decline in the baseline and/or meeting its 1% annual-increase requirement). The "hole" that the facility creates upon leaving the baseline provides a market that is open to competition from any eligible resource. This is how all other QFs are treated under the statute (unless they are specifically excluded under Section 399.12 (a)(3-4)), and it is how existing QF geothermal should be treated as well.

- Similarly, output from a geothermal facility that was not sold to a retail seller in 2001 (primarily, but perhaps not exclusively, non-QF Geysers) that is subsequently sold to a retail seller should permanently increase that retail seller's renewables baseline. When that facility stops selling its output to that retail seller, that output should become generally eligible under the RPS – i.e., it should become eligible to satisfy a retail seller's 1% "net-increase" obligation. As with existing QFs, the "hole" that the facility creates upon leaving the baseline provides a market that is open to competition from any eligible resource.

B. Answers to Staff Questions

[5] There are other resources, namely some biomass facilities, that, like the Geysers, were outside of retail sellers' 2001 portfolios, but which would be eligible to count toward a retail seller's 1% annual-increase requirement. We were aware of this when the legislation was pending, but saw these resources as having much less of an impact on the market intended for new renewables, given their smaller nameplate capacity and their relatively high cost.

Question 1. Was any geothermal energy from a facility that began operating before September 26, 1996 under contract to an Investor Owned Utility (IOU) during 2001? If so, is the expectation that those sales of geothermal generation would become part of that IOU's RPS baseline?

Consistent with our statement above, there was considerable geothermal capacity under QF contract to IOUs in 2001, and 2001 output from those facilities should be counted as part of each purchasing-IOU's RPS baseline.

Question 2. If an IOU contracted for geothermal generation from a facility that began operation before September 26, 1996 as part of its Transitional Procurement, and if that energy is not determined to be "incremental" geothermal energy pursuant to SB 1078, would that energy become an "adjustment" to that IOU's baseline?

Consistent with our statement above, if a retail seller contracts for geothermal generation that was not included in any retail seller's 2001 baseline, it should be counted as an adjustment to the retail seller's 2001 baseline for purposes of SB 1078. It would not satisfy the retailer's 1% annual-increase requirement.

Question 3. If geothermal energy purchased by an IOU as part of its Transitional Procurement is determined to be "incremental" pursuant to SB 1078, would that energy count toward fulfillment of that IOU's RPS Annual Procurement Target? Would such energy be eligible for Supplemental Energy Payments (SEP) pursuant to SB 1038?

Per our comments in answer to Question 6 below, we believe that "incremental" geothermal energy should be limited to production above 2001 field-wide levels. If a facility can document that deliveries in 2002 and beyond constitute such production, that production should be counted toward fulfillment of the annual procurement target of the purchasing retail seller. That production should be eligible for Supplemental Energy Payments only if it derives from the construction of a new or repowered, separately metered, generating unit. Our reasoning is as follows:

(1) SB 1078, Section 399.12(a)(2) – the provision relating to incremental geothermal production -- governs RPS eligibility, not eligibility for PGC funds.

(2) The Commission's latest Guidebook governing the New Renewable Resources Account clearly states, "Any enhancements of fuel source that increase generation at an existing facility, without the construction of a new or repowered, separately metered, generating unit, are not eligible to participate [in an auction for New Account funds]."[6] While the

[6] California Energy Commission, "New Renewable Resources Account Guidebook," Volume 2A, April 2002 (P500-01-014V2A), page 7.

Commission might legally be able to remove this limitation, the Commission has previously put considerable thought into it, and we see no reason to revisit it.

(3) This treatment would parallel the treatment of other existing resources. For example, if a wind project under contract to a utility increases its production above its 2001 level, the utility would be able to count the additional kWh toward its APT. The wind project would qualify for SEP funds only if it is repowered.[7]

Question 4. If the Energy Commission identifies incremental geothermal generation that is not yet under contract to a retail seller, and a retail seller contracts for that incremental generation through a future RPS solicitation, should that energy be eligible for Supplemental Energy Payments?

See our answer to the Question 4.

Question 5. Does the concept of incremental geothermal generation apply only to production from vapor-dominated resources, or is it applicable to liquid-dominated resources as well?

N/A.

Question 6. SB 1078 refers to geothermal "historical production trends." How many years of historical production should the Energy Commission consider?

As we suggested in our introductory remarks, the Commission should seek to treat geothermal resources similarly to other existing resources, unless the statute specifically provides otherwise. Other existing renewables will be counted in the 2001 baseline, and any increases in 2001 production from those facilities should contribute to a utilities' annual procurement targets in subsequent years. "Incremental" production from a geothermal resource that was not in a retailer's 2001 baseline should be limited to production above 2001 field-wide levels.

Question 7. Should such historical production trends be examined on a well-by-well, facility-by-facility basis, or for the geothermal field as a whole?

Incremental production must be measured relative to the entire steam field because, regardless of facility owner, many facilities can, and all facilities at The Geysers steam field do, draw from the same field. This physical reality would enable one facility to draw more steam and produce "incremental" power at the same time that production

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[7] If the repowered project is under QF contract, only the incremental portion of the repower would qualify for SEP payments, while all production would qualify for SEP payments if the repowered project is not under QF contract. This is our understanding of P.U. Code Sections 399.6(c)(1)(C) and 383.5(d)(3), as indicated by staff at the workshop.

from another facility on the same field is declining. The Commission should require applicants for determinations of "incremental" power to demonstrate that total production has increased from the steam field relative to 2001 levels, and should require all owners of facilities drawing from the field to agree on the facilities to which the incremental production should be attributed, based on the each owner's contribution to related capital investments.

The Commission should also require applicants for determinations of "incremental" power to demonstrate that the increased production is sustainable. The State Department of Conservation, Division of Oil, Gas and Geothermal Resources, has documented that, historically, The Geysers' steam resource was unsustainably drawn. It appears that current production levels are stable, but it is important to ensure that production that is allowed to count toward a utility's APT will be sustainable, so that the desire to become RPS- or SEP-eligible does not become an incentive simply to deplete the resource.

Question 8. Should entities that are seeking an Energy Commission determination that a portion of their geothermal generation is incremental be required to make public any data that they use to substantiate such a claim?

With regard to "incremental" production for purposes of above-baseline RPS eligibility, data demonstrating the extent to which overall field production exceeds 2001 levels should be public. The agreement among owners as to which owner(s) should be attributed the increment need not be made public, but should be provided to the Commission. With regard to "incremental" production for purposes of determining eligibility for SEP payments (e.g., documentation of a repower), information supporting the claim should be public, protecting any portions that are legitimately confidential.

Question 9. What criteria should the Energy Commission use in measuring incremental geothermal production? Do the criteria differ depending on whether the geothermal resource is vapor or liquid dominated? What methodology should the Energy Commission use for either case? Should incremental generation be measured in energy (GWh) or capacity (MW) terms?

See our answers to Questions 5, 7 and 8. Incremental generation should be measured in GWh, as the RPS is an energy requirement.

Question 10. What constitutes capital investment that results in incremental production, rather than maintenance of production? How should the Energy Commission distinguish between investments that increase production versus investments that maintain production in the context of a declining historical production trend?

This issue can be simplified if the Commission simply looks to any production that exceeds 2001 levels, per our answers above. This methodology would not require the Commission to make the very difficult determination of whether increases are attributable to "maintenance" that restored a portion of pre-2001 production (production at The Geysers has declined considerably over the past several years) or to "investments" that boosted production. It is likely to be very difficult to objectively distinguish between the two, and to prevent gaming.

Our response to the assertion made at the workshop that accounting documents can serve to identify incremental improvements is this: Just because an investment is classified under accounting rules as a "capital expenditure" does not mean that that expenditure was not conducted as a part of routine maintenance. Replacing wellfields is standard practice in the geothermal industry.

Moreover, it would be incongruent to allow geothermal resources to count as "incremental" production that which stems from investments that merely maintain historical production levels, while not providing such treatment for the capital repairs that are necessary to keep wind projects operating at consistent levels, or the new wells that must be drilled in, or new trash that must be added to, a landfill to prevent the significant declines that would otherwise occur.

Question 11. Do investments in wastewater injection projects result in incremental production? How is this incremental production measured on a facility basis?

If investments in wastewater injection projects sustainably boost production over 2001 levels, that production should be counted as "incremental" per our comments above, but it should not qualify for Supplemental Energy Payments, as it would not "derive from the construction of a new or repowered, separately metered, generating unit." (See our answer to Question 3.)

Question 12. If the Energy Commission certifies an amount of incremental geothermal production, would that amount be a constant, or might it change over time? For example, if a declining trend is established, and it is shown that through capital investment that decline has been stabilized, might the amount that is incremental be regarded as increasing over time?

Again, measuring incremental production relative to 2001 levels simplifies this issue, as whatever generation occurs above this level each year would qualify as "incremental."

Question 13. If you are an entity seeking to have the Energy Commission certify a portion of your geothermal production as incremental, what do you claim your incremental generation to be? In substantiating such claim, please detail the capital investments made, how they have contributed to incremental production, what historical production trends they have altered, and how Questions 9 – 11 are reflected in your claim.

N/A.

Question 14. If you are an entity who expects to dispute claims of incremental geothermal generation, on what basis do you expect to dispute such claims?

N/A.

Question 15. If a portion of the generation from a geothermal facility (or from a geothermal field) is determined to be incremental, and if only a portion of the generation from that unit (or from that geothermal field) is sold to an IOU pursuant to an RPS solicitation, how is one to determine whether the kilowatt-hour sold to the IOU is "incremental" or "existing?"

Per our answer to Question 7, the owners of all facilities tapping the same resource should agree amongst themselves which owner should be granted the "incremental" production. Each owner should allocate its incremental production equally among its facilities unless it can demonstrate that its investments substantially serve only a subset of its facilities.

Question 16. Within the Geysers, can steam be shifted from one generating unit to another? If so, and if incremental geothermal generation were determined on a unit-by-unit basis, could "existing" steam from one or more units be shifted to another unit so as to make that unit appear to have "incremental" generation when it really does not? If it can, how can the Energy Commission prevent such manipulation?

See our answer to Question 7. Manipulation can only be prevented by measuring "incremental" relative to production from the entire steam field.

II. "In-State Renewable Electricity Generation Technology Facility" Definition Issues

We do not address questions pertaining to biomass, small hydro, and municipal solid waste, other than to say that the same threshold question that pertains to geothermal that we set forth in our introductory comments also applies to small hydro and municipal solid waste. The Commission should find that, as with the subsection pertaining to geothermal, subsections 399.12 (a)(3) and (4) should also be found to be relevant.

III. Eligibility of Out-of-State Power

Our comments on this issue incorporate those that we provided on January 6, 2003, in response to the California Public Utilities Commission's ("CPUC") request for comments in Section V(B)(2) of Decision 02-10-062 ("Framework Decision") on the legality and potential benefits of allowing out-of-state renewable generation resources to participate in the RPS Program.

Out-of-state renewable resources should be included in the RPS Program because out-of-state renewable resources further the legislative goals of the RPS Program by increasing competition amongst renewables and providing Californians access to potentially lower-cost renewable resources. Since procurement of in-state and out-of-state renewable resources have similar potential to displace the need for in-state fossil-fuel generation and to reduce demand in regional fossil fuel markets (depending on the specifics of each project, transmission system expansions and other factors), California would likely reap the benefits of lower and more stable energy prices, improved environmental quality and improved public health as long as the renewable facility sells and delivers its output to an in-state IOU and is located in the Western market in which California operates.[8]

As the CPUC recognized, the California Legislature seemed to contemplate harmonization of eligibility requirements for the PGC-funded Renewable Energy Program ("REP") and the RPS Program, but the exact language of the RPS Program legislation has created some ambiguity. Framework Decision at 20; *see* CAL. PUB. UTIL. CODE § 399.12(a)(1). While the REP legislation seems to be restricted to in-state renewable electricity generation technology facilities,[9] it also allows the Energy Commission to grant PGC funds to renewable facilities outside the state if it meets both of the following requirements: (i) it is located so that it is or will be connected to the WECC transmission system; and (ii) it is developed with guaranteed contracts to sell its generation to end use customers subject to the funding requirements or to marketers that provide this guarantee for resale of the generation. CAL. PUB. UTIL. CODE § 399.12(d)(2)(B). The latter provision would have no effect if the Commission were to limit RPS eligibility to in-state facilities, since PGC funds may only be applied to RPS-eligible facilities.

The California Legislature's intent could be made more clear through the legislative process but it is clear that the RPS Program legislation intended its eligibility requirement to mirror the REP's eligibility requirement, which includes out-of-state renewable resources under certain conditions. Furthermore, the inclusion of out-of-state resources in the RPS Program is consistent with the physical Western United States energy market in which California operates.

In addition to the foregoing, a limit of eligibility under the RPS Program to only renewables physically installed in the State of California may raise issues under the Commerce Clause of the United States Constitution. As the Commission is no doubt

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[8] Of course, in-state renewable resources provide additional benefits to the State of California, such as property tax revenues, sales tax revenues, long-term job growth and short-term construction employment opportunities.

[9] The REP defines in-state renewable electricity generation technology facility as one "located in the state or near the border of the state with the first point of interconnection to the Western Electricity Coordinating Council (WECC) transmission system located within this state." CAL. PUB. UTIL. CODE § 383.5(b)(1)(B).

aware, a state government may regulate local aspects of interstate commerce only if it does not discriminate against or unduly burden interstate commerce. Maine v. Taylor, 477 U.S. 131, 138 (1986) (quoting Hughes v. Oklahoma, 441 U.S. 322, 336 (1979)); *see also* New Energy Co. of Indiana v. Limbach, 486 U.S. 269, 276 (1988). A discriminatory law can be valid only if it furthers an important non-economic state interest and no reasonable non-discriminatory alternatives are available. Id. We believe it would be difficult for an in-state RPS requirement to meet this test.[10]

No comment on Questions 36, 37, and 40.

Question 38. Could out-of-state power be certified as an eligible renewable resource for purposes of meeting the RPS? Could such out-of-state power include power from Mexico?

If the Commission believes, as we do, that the RPS Program legislation intended its eligibility requirement to mirror the REP's eligibility requirement, which includes out-of-state renewable resources under certain conditions, then out-of-state power, including power from Mexico, should be certified as an eligible renewable resource if it meets the legislative requirements: (i) it is or will be connected to the WECC transmission system; and (ii) it is developed with guaranteed contracts to sell its generation to end use customers subject to the funding requirements or to marketers that provide this guarantee for resale of the generation. In addition, the Commission should require the power to be delivered – i.e., scheduled and transmitted -- into the CAISO control area. A delivery requirement is necessary to ensure that the dispatch of fossil fuel plants located in California is affected by the renewable facility that benefits from the California RPS. Also see our answer to Question 39.

Question 39. For power from out-of-state sources, how could we verify that the power is produced using an eligible electricity generating technology?

One of the possible concerns in allowing out-of-state renewable resources to participate in the RPS Program may be that the Commission cannot extend its reach past the borders of the State of California. As such, some may be concerned that the Commission will be unable to exert oversight over out-of-state renewable resources or that out-of-state renewables might complicate compliance with RPS Program rules. These concerns are unfounded. The Commission and the CPUC may reasonably precondition participation by out-of-state renewable resources in the RPS Program on their contractual consent to the same amount of Commission oversight as in-state

[10] See: (1) Kirsten Engel, "The Dormant Commerce Clause Threat to Market-Based Environmental Regulation: The Case of Electricity Deregulation." *Ecology Law Quarterly*. Vol. 26 No. 2. (1999); (2) Nancy Rader and Scott Hempling, *The Renewables Portfolio Standard: A Practical Guide* (Appendix A), National Association of Regulatory Utility Commissioners. February 2001.

resources. The out-of-state renewable resources would therefore be contractually bound within the same reach of the two commissions as in-state renewable resources.

Out-of-state resources should be subject to the same eligibility verification procedures as in-state resources. If the Commission is unable to independently verify eligibility, it should require an out-of-state applicant to provide sufficient evidence and/or independent verification of eligibility. The Commission may wish to consult with New England states that have RPS laws but which do not limit eligibility to in-state resources (Maine, Massachusetts, and Connecticut) to see what procedures they use to verify eligibility of out-of-state resources.

Question 41. To the extent that out-of-state power is represented for sale in California through Renewable Energy Credits, or RECs, is this power eligible for the RPS? For SEP payments? If so, should any constraints be placed on the eligibility and tradability of these RECs? For example, should RECs associated with energy that is eligible for SEP payments not be tradeable?

The <u>power</u> from an out-of-state facility should be eligible for the RPS and SEP payments if it (a) meets resource eligibility requirements, (b) is <u>developed</u> with a contract to sell its generation to a retail seller that is obligated under the RPS, (c) is connected to the WECC system, and sells and delivers (i.e., schedules and transmits) its output into the CAISO control area (which serves in-state retail sellers subject to the RPS requirement). If these requirements are met, then, under a REC system, the RECs associated with this power should also be eligible for the RPS, and should be subject to the same rules governing RECs generally, including trading rules.

Our recommendation is grounded in the legislative requirement in P.U. Code Sec. 383.5(d)(2)(B) that out-of-state power be "developed with guaranteed contracts to sell its generation to end use customers subject to the funding requirements of Section 381" (i.e., subject to PGC funding requirements, a condition that is satisfied when the facility sells its power to a retail seller that is obligated under the RPS). The CAISO delivery requirement can be inferred from the legislative requirement to "sell" the renewable power to the RPS-obligated retail seller.

These requirements are also necessary to achieve the following benefits, which the legislature declared as its reasons for adopting the RPS legislation (P.U. Code Sec. 399.11):

(1) <u>In-state environmental benefits</u> are secured for Californians by the deliverability requirement, which is necessary (for both in-state and out-of-state renewables) to ensure that the dispatch of fossil fuel plants located in California is affected by the renewable facility that benefits from the California RPS. The power delivery requirement can be tracked through a robust REC system, such as NEPOOL's GIS system.

(2) Stable pricing benefits are encouraged by the power sale requirement, which will prevent RECs disassociated from a power sale from being counted toward RPS compliance. (Renewable power facilities are able to sell power at fixed prices.)

(3) The development of new renewable energy facilities – beyond those that have been built throughout the West since 1996 – is promoted by requiring the facility to be developed for sale to an RPS-obligated retail seller. Without this requirement, an existing, post-1996, out-of-state renewable project could arrange to sell its power into the RPS market, which would reduce the demand for new renewables that the California RPS would otherwise create, thereby reducing the additional environmental benefits and gas-demand-reduction benefits that such facilities would provide. The in-state deliverability requirement will also promote the development of new facilities, since existing facilities may be less able to redirect their power sales than to redirect sales of their RECs.

RECs alone should not be eligible for PGC payments because (a) it will be difficult to measure the "above benchmark" cost of a REC, since the benchmark is a long-term fixed price product which cannot easily be measured against short-term REC sales (as well as spot market power); and (b) the RPS was intended to foster long-term power contracts (as is implied by the "developed with guaranteed contracts to sell" clause). Supplemental Energy Payments should be applied only to output from a facility that has a long-term contract with a retail seller that is obligated under the RPS or to an intermediary that demonstrates that it is reselling the power to such a retail seller or sellers.

Thank you for considering our views. Please contact me if I can provide further information on any of our comments.

Respectfully submitted,

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March 28, 2003