BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop Additional Methods to Implement the California Renewables Portfolio Standard Program.	R.06-02-012

POST-WORKSHOP COMMENTS OF THE ALLIANCE FOR RETAIL ENERGY MARKETS AND THE WESTERN POWER TRADING FORUM ON TRADABLE RENEWABLE ENERGY CREDITS

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In accordance with the Administrative Law Judge's Ruling Requesting Post-Workshop Comments on Tradable Renewable Energy Credits ("Ruling") issued by Administrative Law Judge ("ALJ") Anne E. Simon on October 16, 2007, the Alliance for Retail Energy Markets ("AReM") and the Western Power Trading Forum ("WPTF") respectfully submit these joint comments.[1]

A. INTRODUCTION

Both AReM and WPTF have a vital interest in the development of a competitive electric market and in the reduction of barriers that may exist in the structure of new markets. AReM and WPTF reiterate our strong support for tradable Renewable Energy Credits ("RECs") as a useful and much needed flexible compliance tool for energy service providers ("ESPs") and other load-serving entities ("LSEs"). As requested by ALJ Simon, AReM and WPTF comment herein on the proposed Guiding Principles for REC trading and Staff's post-workshop questions.

[1] AReM is a California non-profit mutual benefit corporation that was formed by electric service providers that are active in California's direct access market. The positions taken in this filing represent the views of AReM and its members but not necessarily those of the affiliates of its members with respect to the issues addressed herein.

B. PROPOSED GUIDING PRINCIPLES

As noted in our joint pre-workshop comments, AReM and WPTF agree with the proposed Guiding Principles. We recommend, however, that Principle 8 be amended to state: "REC trading rules, guidelines, and policies should be simple, transparent, easily administered, uniformly applied, and equitable to all *participants*." Assuming that the REC trading market will be open to a myriad of participants beyond LSEs and ESPs, which AReM and WPTF support, we believe that the rules, guidelines and policies governing REC trading should be equitable to all that participate.

C. RESPONSES TO STAFF QUESTIONS

1. Basics of a Tradable REC Market

(1) Of the following statements from Attachment D, please agree or disagree with each, and provide justification based on specific experiences and/or economic analysis.

(a) Tradable RECs will not affect current factors limiting new renewable energy projects in California. The limiting factors include: lack of adequate transmission infrastructure, complex and lengthy permitting processes, and in-state delivery requirements for RPS-eligible generation.

AReM and WPTF disagree with this statement. As previously noted by several parties, tradable RECs will help overcome transmission barriers by making RECs available to LSEs for compliance without the need to build new transmission lines to directly connect remote renewable resources with load centers. Moreover, this statement fails to recognize the significant contribution that customer-owned distributed generation ("DG") is making to the development of new renewable energy projects in California. These projects are not limited by transmission infrastructure, complex and lengthy permitting processes, or in-state delivery requirements. Rather these projects deliver directly into California's distribution system, and generally are able to come on-line quickly. Also importantly, the ability to sell tradable RECs

will provide DG owners a potential additional revenue stream that can bolster the economics of these installations and foster the development of additional customer-owned DG.

(b) Tradable RECs will provide buyers and sellers of RPS-eligible generation with additional contracting flexibility in the near term and long term.

AReM and WPTF agree with this statement. Tradable RECs provide buyers and sellers of RPS-eligible generation with additional contracting flexibility in at least two ways. First, for DG resources that have already been installed, tradable RECs provide a means for these projects (such as solar developed under the CEC's Emerging Resources Program and under the CPUC's Self-Generation Incentive Program) to contract for the sale of these RECs in the near-term to buyers that have immediate needs for more renewables than are currently available to meet their RPS compliance requirements. For new projects that are installed under the California Solar Initiative, tradable RECs will provide a means to generate an additional revenue stream for DG installations while helping buyers meet their RPS compliance requirements. Second, for buyers who have already procured sufficient energy needed to serve their customer loads, the ability to purchase unbundled RECs, without the corresponding null power, will provide needed flexibility to meet their rapidly increasing RPS requirements. Lastly, the unbundled RECs may be valuable to individual businesses, institutions and organizations in the voluntary renewables market as such entities want to demonstrate their support for renewables by "greening up" their energy purchases, thereby affording yet another revenue stream for DG owners.

(c) Tradable RECs will facilitate RPS compliance for small LSEs, but will only marginally affect large IOUs' RPS compliance in the near term (i.e. until the 20% target is reached).

AReM and WPTF can only comment on the affect tradable RECs will have for our ESP members, which are small LSEs. We can unequivocally state that tradable RECs will greatly

facilitate RPS compliance for our members by affording small LSEs with an important flexible compliance tool that is currently missing from California's RPS program.

(d) Given the stringent RPS targets and limited supply of surplus renewable energy in the near term (at least until the 20% target is reached), the California REC market would reflect a supply and demand imbalance.

This statement misses the point. The renewables market will reflect a supply and demand imbalance, regardless of whether RECs are bundled with the energy or sold as a stand-alone product. The value of bundled RECs is incorporated by default into bundled renewable energy prices. However, having the ability to unbundle RECs and to contract for RECs separately will open up the additional REC supply from sources such as DG installations, which will help to alleviate the supply/demand imbalance. Based on the goals of the California Solar Initiative, there should be almost 800 GWh of new renewable generation resulting from this program that will be available by 2010.

(2) What are the most likely sources of RECs that could be traded in the 2008-2011 timeframe? Please focus on RECs associated with generation that will meet the delivery requirements of Pub. Util. Code §399.16(a)(3).

Public Utilities Code §399.16(a)(3) requires that RECs must be derived from electricity that "is delivered to a retail seller, the Independent System Operator, or a local publicly owned electric utility." Because DG is connected with the distribution grid, we interpret § 399.16(a)(3) to encompass DG RECs. As shown in Table 1, which was produced based on information in the *California Solar Initiative Program Handbook* dated September 2007, by 2011 over 1100 GWh of energy from new renewable generation is expected to be produced annually from the CPUC portion of the California Solar Initiative. While this assumes that each step of the CSI will be achieved in the course of one year, the commercial portion of the CSI has already reached Step 4

for all three utility areas, suggesting that RECs from this source will *exceed* 1100 annual GWh by 2011.

Table 1

California Solar Initiative - Expected Energy Production

Step	Possible Year	CA Residential (MW)	CA Commercial (MW)	CA Total (MW)	Default Capacity Factor (1)	Total Expected Residential GWh in step	Cumulative Expected Residential GWh	Total Expected Commercial GWh in step	Cumulative Expected Commercial GWh	Total Cumulative Expected GWh
2	2007	23.1	46.9	70	18%	36	**36**	74	**74**	110
3	2008	33	67	100	18%	52	88	106	**180**	268
4	2009	42.8	87.2	130	20%	75	163	153	332	496
5	2010	52.8	107.1	159.9	20%	93	256	188	520	776
6	2011	62.7	127.3	190	20%	110	366	223	743	1109
7	2012	70.9	144	214.9	20%	124	490	252	995	1485
8	2013	82.6	167.6	250.2	20%	145	635	294	1289	1924
9	2014	94.1	190.9	285	20%	165	800	334	1623	2423
10	2015	115.5	234.6	350.1	20%	202	1002	411	2034	3036
		577.5	1172.6	1750.1						

(1) Per CSI Handbook

Out-of-state resources are another potential source of tradable RECs in the near term. As neighboring states are also implementing RPS programs, demand for renewables will be increasing throughout the region. The opportunity to sell RECs into the California market may provide an incentive for these out-of-state resources to build larger facilities that can serve both local and California demand for renewables.

(3) Please revisit the following two issues discussed in pre-workshop comments in light of the presentations and discussion at the workshop:

(a) How, if at all, would REC trading, as compared to the current firming and shaping rules for delivery of RPS-eligible power into California, provide more flexibility or be less costly for procuring out-of-state renewable energy?

The following example illustrates how REC trading would provide more flexibility and could be less costly for procuring from out-of-state resources: An LSE procures energy from new renewable resources outside of California and delivers that renewable energy into California. The LSE determines that it needs this energy for firming and shaping needs for its customers, but does not need the RECs associated with it. The LSE could sell the RECs to another LSE that is short on renewables. This provides the LSE with additional flexibility to

procure the energy that meets its customers' needs, while mitigating the costs from procuring from out-of-state renewable resources.

(b) How, if at all, would REC trading, as compared to current RPS flexible delivery rules, provide more flexibility or be less costly in overcoming transmission congestion constraints? Please provide specific examples of situations in which REC trading would enable renewable energy projects to be developed in transmission constrained areas in California that would not otherwise be feasible.

AReM and WPTF commented on this topic in their joint pre-workshop comments:

> REC trading will mitigate transmission congestion problems by allowing LSEs to "access" renewable generation resources in remote areas and neighboring states without the need for associated energy to be transmitted across congested lines. Under a purely physical, point-to-point visualization of the RPS, construction of otherwise unneeded transmission would be required in order for LSEs to physically access the generation for RPS compliance purposes. Under a REC trading regime, the amount of transmission constructed that is needed is limited to that required to connect renewable resources to the grid. Without the use of tradable RECs, in a worst case scenario, one could expect to see construction of transmission from a remote resource to a load center that would otherwise be unnecessary, solely to accommodate a regulatory requirement that a (fictional) "contract path" be traceable from a resource to an LSE's load. In contrast, using the simpler requirement – that the grid have sufficient transmission in place to constructively utilize the renewable power – much less transmission would need to be built. This is an important consideration given the uneven physical distribution of renewable generation resources in California and neighboring states.[2]

(4) Describe the foreseeable market in California and neighboring states for null power in the timeframe 2008-2011.

AReM members may be potential purchasers of null intermittent or firm power to meet their fluctuating loads or to firm up other renewable energy contracts. Additionally, market intermediaries can be expected to buy and sell null power on a regular basis since there will be demand from LSEs for energy to meet the non-RPS energy requirements of their customers.

[2] AReM and WPTF Pre-Workshop Comments, p. 10.

California remains a market with strong energy demand during much of the year and null power can help to fulfill this rising demand.

(5) Please comment on Dr. Weiss's assessment of the elasticity of RPS demand and supply curves.

Dr. Weiss states, "Demand is drive by the RPS itself and, absent banking and borrowing, is essentially perfectly inelastic at the RPS level." He further states, "[G]iven the uncertainty of both REC supply and demand in any given compliance period, the price of RECs implied by the intersection of supply and demand is expected to fluctuate between very high levels (if there is a supply shortage) and very low levels (if there is excess supply), but rarely at intermediate level." In reality, however, there will be an extremely large range of RPS demand elasticity in any given year since LSEs have flexible compliance options, including: (1) unlimited forward banking; (2) deferral of a deficit of up to 25% of one's IPT for up to three years; and (3) deferral of a deficit of more than 25% of an IPT with earmarked contracts for up to 3 years. Assuming all LSEs deferred 25% of a particular year's IPT, and deferred another 10% of a deficit with earmarked contracts, the RPS demand would be only 65% of what was expected. Thus banking and borrowing moves the demand curve away from the vertical position that is the product of Dr. Weiss' assessment. As John Pappas from PG&E remarked at the workshop, the three-year RPS compliance window in California makes it unclear what the actual supply/demand curve will look like.

Also, in Dr. Weiss's analysis, he seems to assume that purchases of RECs for RPS compliance will be made by all LSEs at the very end of a compliance period, when it will be obvious that there is either a shortage or surplus of RECs. This is not a reasonable assumption, however, as LSEs who utilize tradable RECs for compliance will likely purchase them throughout the compliance period on a monthly or quarterly basis, and leave only a small

percentage for purchase at the end of a compliance period when the exact amounts they need for true up are known. This would be similar to purchasing stocks using a dollar-cost averaging approach, to avoid the volatility of daily price fluctuations. Additionally, many LSEs may look at forward contracting as a mechanism for procuring RECs to both ensure they have procured supply to meet their RPS compliance obligations as well as to provide price certainty.

(6) If demand for tradable RECs for RPS compliance exceeds supply in the California REC market (at least in the near term), do you agree with Dr. Weiss's analysis that REC prices would tend to float to the RPS penalty amount ($50/MWh)? Would prices float to any other price cap the Commission might implement?

Based on evidence from other REC markets (such as the New Jersey Solar REC market), if the expectation is that demand will exceed supply, REC prices can reasonably be expected to float to a price somewhere below the penalty amount, as the trading price reflects the transaction costs inherent in purchasing RECs. During the first year of New Jersey Solar REC program, demand outstripped supply, but the cumulative weighted average price of the solar RECs was $200.59/MWh, when the solar alternative compliance payment ("ACP") amount was $300/MWh.[3] Thus, the trading price was 33% below the penalty amount.

Compliance with the Massachusetts RPS is demonstrated completely through the purchase and retirement of RECs that are tracked through the New England GIS, which is very similar to WREGIS. Evolution Markets recently reported the results of an auction of 2008 RECs for the Massachusetts compliance market[4]. The average price of the RECs in their auction was $52.52/REC. The ACP amount for 2008 will not be announced until January 2008, but he 2007 amount is $57.12. (Based on previous annual increases, the 2008 ACP amount will likely be

[3] http://www.njcleanenergy.com/renewable-energy/programs/solar-renewable-energy-certificates-srec/public-reports/public-reports

[4] "Evolution Markets Completes Forward Auction of Massachusetts Renewable Certificates for Massachusetts Technology Collaborative", October 25, 2007, www.evomarkets.com.

around $59.12.) Thus the RECs sold in the 2008 auction traded at a discount of 11% from the expected 2008 ACP. In 2005, compliance with the Massachusetts RPS was short by about 33% due to lack of sufficient renewable resources. ACP payments were made to make up for this shortfall. New resources were under construction in 2006 and 2007, although shortfalls are still expected for 2007 and 2008.[5] Thus, the REC price has not floated up to the ACP price, but rather reflects a discount, even under a tight RPS market, and when RECs are the only option for meeting the RPS requirement.

One key difference between California and other states is that the non-compliance penalty incurred by a California LSE is an ongoing payment for shortages, not a one-time ACP as it is in other states. Since any penalties incurred by the IOUs will be paid by their shareholders (whereas the costs of their REC purchases will be paid by ratepayers), the IOUs have a significant incentive to avoid penalties. (ESPs have a significant incentive to avoid penalties since they operate in a highly competitive environment and are unlikely to be able to pass on the increased costs from penalties to their customers.) If the CPUC is only going to view costs below a cap or the penalty amount as "reasonable," then the CPUC will have to include the transaction costs for purchasing RECs in making that determination. Thus, the price for RECs should not ever reach the cap or penalty amount since the IOUs will face a disallowance for the transaction costs.

(a) If REC prices floated to the penalty amount or a price cap, would a market for tradable RECs drive up the price of bundled RPS contracts?

No, since LSEs will endeavor to fulfill their RPS compliance obligations in the most economical manner, whether that is through the procurement of bundled renewable energy and

[5] Massachusetts Renewable Energy Portfolio Standard, Annual RPS Compliance Report 2005, February 20, 2007 (Corrected August 23, 2007), Division of Energy Resources Executive Office of Energy and Environmental Affairs, Commonwealth of Massachusetts.

RECs or the purchase of tradable RECs, or both. AReM and WPTF recommend that the REC trading market be allowed to develop on its own. After a few years, the dynamics of the REC trading market can be examined to determine if there are any market problems that require "fixes" or regulatory intervention.

(b) If REC prices floated to the penalty amount or a price cap, how would this affect California ratepayers in the short term? In the long term?

Based on our members' experience in other renewables markets, AReM and WPTF expect that REC prices will be driven primarily by supply and demand conditions in the marketplace, not the penalty amount or an administratively determined price cap.

(c) If REC prices floated to the penalty amount or a price cap, would all RPS non-compliance costs then be transferred from utility shareholders to ratepayers? Would some portion of non-compliance costs be transferred?

AReM and WPTF reserve further comment on this issue, as we believe it is only applicable to the IOUs (and possibly non-IOU LSEs other than ESPs).

(7) Dr. Weiss presents an analysis of REC markets showing a bimodal pricing distribution, colloquially referred to as "boom-bust" pricing.

(a) Please describe any situations in a California REC market in which the boom-bust pricing pattern is likely <u>not</u> to apply.

The boom-bust pricing pattern hypothesized by Dr. Weiss is predicated on the assumption that demand for renewable energy and RECs for RPS compliance will be inelastic in any given year. However, because of the elasticity in demand corresponding to the ability of LSEs to forward bank and defer deficits for up to three years, Dr. Weiss' analysis does not reflect the reality of the situation. Additionally, purchasing tradable RECs is only one compliance option, and the fact that Dr. Weiss does not take into account the other options available to RPS-obligated entities makes his analysis more than highly speculative.

(b) In the timeframe 2008-2011, are contracts for RECs likely to provide developers of new renewable facilities in California and neighboring states with additional financial resources (both in terms of cash flow for the facility and in terms of willingness of investors and/or lenders to provide capital for development of the facility)? Why or why not?

Tradable RECs will be a potential source of revenues that could facilitate financing for developers of renewable projects. In addition, tradable RECs will provide another revenue stream that renewable facility owners will have available to maximize the value of their assets. For example, developers of solar DG projects will have a new cash stream available to help them finance their projects, which will be ever more important as the incentive levels under the CSI continue to be reduced. Also, the Center for Energy Efficiency and Renewable Technologies ("CEERT") has noted: "Procurement of RECs generated from eligible out-of-state facilities located within the WECC region will add to the procurement options available to LSEs to meet their RPS annual procurement targets ("APTs") and will also facilitate renewable energy projects being developed in the most cost-effective regional locations."[6] And CPV Renewable Energy Company, LLC ("CPV") has observed: "[REC] unbundling and trading will reduce transaction costs for RPS compliance for both IOUs and smaller LSEs, and will provide additional value both to California's ratepayers and to developers of renewable energy facilities."[7] Indeed, the record abounds with similar statements of support for tradable RECs from the developer community.

(c) Please describe how the design of a tradable REC market for compliance with the California RPS should take into account the boom-bust pricing tendency.

As previously noted, the premise of demand inelasticity that will give rise to a boom-bust pricing pattern is invalid given the multitude of flexible compliance options available for RPS

[6] CEERT Pre-Workshop Comments, p. 23.
[7] CPV Pre-Workshop Comments, p. 6.

obligated LSEs. Therefore, there is no need to try to predict how this hypothetical pricing patter would affect the market, and therefore no need to develop complex rules to address this non-problem that could end up causing unexpected aberrations in the market.

2. Staff Straw Proposal

AReM and WPTF describe below specific suggestions for improvements and changes to Staff's straw proposal.

(1) For each area of the straw proposal, please address the following issues, as well as any other issues that would contribute to a complete discussion of the straw proposal. Please provide all information necessary to support the analysis presented in the comments. Where relevant, please comment on the rationale provided by staff for each area.

(a) Impact on and integration with the existing methods of RPS compliance, including both procurement methods and existing flexible compliance rules.

Market Participants: We suggest that the second item in the straw proposal be revised to read as follows: "To the greatest extent possible, rules should be equitable for all participants." The rationale for this is based on our comments on Guiding Principle 8, that the REC trading rules should be "equitable to all participants", and reflect the differences that exist between different types of participants.

TREC Usage Limits: The second item in the straw proposal proposes changing the existing "trigger" requirement for the use of short term contracts to meet the RPS. It appears that Staff's intent is to add a different requirement for allowing the use of RECs, in that expected deliveries *during the compliance year* must by 0.25% of the prior year's sales. This is in contrast to the requirement for the use of short-term contracts, which states that expected deliveries from long-term or new generation contracts *over the life of the contract* is 0.25% of the prior year's

sales. We provide additional analysis about this portion of the straw proposal in answer to question (2) below.

Earmarking: The straw proposal prevents using contracts for RECs for earmarking. The first rationale objecting to earmarking, that it would create unnecessary administrative complexity, is not a valid reason to reject the use of earmarking. Earmarking of contracts for RECs is the same as earmarking contracts for energy; if the facility where the earmarked RECs or energy does not get built, the LSE is still required to meet its RPS compliance obligations by purchasing from another source to make up the shortfall or face a penalty. Allowing earmarking for energy but not for RECs is an inconsistent policy.

Treatment of Bundled Contracts: The straw proposal talks about January 1, 2009 as the first date for the use of unbundled RECs from currently operational RPS projects or from planned projects. However, AReM and WPTF note the following:

- Since the Western Renewable Energy Generation Information System ("WREGIS") is now operational as a tracking and verification system for both energy and unbundled REC purchases, we do not believe it makes sense to wait an additional year to utilize the features of WREGIS for tracing and counting RECs for RPS compliance. One of the rationales for using WREGIS is to avoid double counting; thus the sooner WREGIS is utilized, the sooner the market can be assured that double counting of renewable attributes is not taking place.

- SB 107 does not require that tradable RECs can only be utilized for compliance after January 1, 2009. If that had been the legislative intent, it would have been specified in the legislation. Instead the legislation only requires that the tracking system be operational, which is the case with WREGIS. In fact, it is the intent of the California Energy Commission that WREGIS be used to track all renewable attributes used for RPS compliance starting in 2008.

- The straw proposal does not address currently operational DG projects that have RECs available to sell. Based on the current straw proposal, it appears again that RECs associated with these projects cannot be sold until 2009. However, WREGIS can track these RECs today. These projects can monetize their RECs now, and LSEs can purchase these RECs now to assist them with achieving RPS compliance in a timely manner.

- The straw proposal is silent regarding projects that come online in 2008. Again, projects that come online in 2008 can sell their RECs as soon as they are operational, and should not be required to wait until 2009 to do so.

Cost Recovery: The straw proposal states, "Long Term REC contracts must be filed with the Commission by advice letter…." This should be revised to read: "*IOU* Long Term REC contracts must be filed with the Commission by advice letter…."

(b) Impact on and integration with the existing methods of RPS reporting.

With the availability of WREGIS and the requirement that all RPS eligible resources are tracked through the system, RPS compliance verification and reporting will be streamlined and more accurate. WREGIS essentially tracks the RECs associated with all renewable energy generated. Allowing the REC to be separated from the energy and still used to meet RPS compliance would be more consistent with the use of the WREGIS system. For transactions where the REC is bundled with the energy, these would still be tracked through WREGIS, which will provide for a complete picture of the renewable energy and REC deliveries associated with RPS compliance.

(c) Impact on the development of new renewable resources in California and neighboring states.

As we and other parties have stated earlier, the use of RECs provides an additional revenue stream and additional flexibility in contracting with renewable plant developers both in-state and out-of-state. Additionally the use of tradable RECs provides optionality to an LSE (or other party) who develops a renewable facility or contracts for the output of a new facility by giving them the ability to easily sell renewable attributes in excess of what they need to meet their own compliance obligations. This provides a hedge against the potential cost of over-procurement of RPS resources that could result because of load migration. The ability to sell off

excess RECs in the future will mitigate the cost recovery risks for small LSEs of forward contracting and can contribute to the development of renewable resources.

(d) Impact on RPS compliance in the timeframe 2008-2011.

Provided the problems with the proposed TREC Usage Limits are addressed, the use of tradable RECs will provide additional flexibility that will greatly aid our ESP members and other small LSEs achieve RPS compliance in the 2008-2011 timeframe.

(e) Impact on RPS compliance in the timeframe 2012-2020,

(1) with the existing mandate of 20% of electricity sold at retail in California to be generated by eligible renewable resources by 2010, and

(2) with a new mandate of 33% of electricity sold at retail in California to be generated by eligible renewable resources by 2020, with the current statutory framework for RPS otherwise unchanged.

Provided the problems with the proposed TREC Usage Limits are addressed, the use of RECs will provide additional flexibility in allowing our ESP members and other small LSEs to achieve RPS compliance in the 2012-2020 timeframe. Additionally, once the 20% mandate is achieved, we assume the additional TREC Usage Limits and long-term contracting limits will be removed, as is the case with regards the need to reach a "trigger" of new generation purchasing or long term contacting in order to utilize short term contracts in any given year to meet the RPS.

(f) Impact on the development of a market for tradable RECs for RPS compliance.

The inclusion of all market participants, as proposed in the Straw Proposal, will be a positive factor in the development of a robust market for tradable RECs for RPS compliance.

(g) Impact on and integration with a possible market of tradable allowances for compliance with the Global Warming Solutions Act, Assembly Bill (AB) 32 (Nuñez/Pavley), 2006 Stats. ch. 488.9

As the structure of a market for tradable allowances under AB32 is still under discussion, we are unable to predict how this might develop. However, as noted below, a requirement for the bundling of GHG attributes with RECs may be incompatible with a GHG emissions cap and trade system.

(2) In order to evaluate the TREC usage limits section of the straw proposal, please comment on whether the minimum quota proposal would help:

(a) maintain a focus on new renewable infrastructure development;

(b) reduce ratepayer compliance costs that might otherwise result from a high demand for RECs relative to available supply;

(c) enable RPS procurement to remain a hedge against volatile natural gas prices;

(d) respond to the impact of supply and demand on REC market prices and liquidity by imposing more stringent minimum contracting requirements for short-term REC contracts than for short-term bundled contracts.

The more stringent minimum contracting requirement for short-term REC contracts over short-term bundled contracts will not alleviate the impact of supply and demand on REC market prices and liquidity. Rather it will cause confusion in the market as the result of having two different standards, and will have a negative effect on REC market prices and liquidity.

1) The more stringent contracting requirements will make it difficult to monitor 2 different standards, causing disruption to the RPS program.

The proposed TREC Usage Limits are not consistent with Guiding Principle 2, which asserts that REC trading should result in minimal disruption to the current RPS program. To the contrary, REC trading will result in minimal disruption to the current RPS program, but only if the same standards are applied for both energy purchases and REC purchases. A long-term REC

contract should be considered the same as a long-term energy contract; likewise, a short-term REC contract should be considered the same as a short-term energy contract. Additionally, it is highly desirable to have the minimum contracting/new generation purchasing component remain the same for both the ability to utilize short-term contracts and the ability to purchase RECs in order to be consistent with Guiding Principle 2.

2) The more stringent contracting requirements will result in a negative effect on REC prices and liquidity.

The proposed TREC Usage Limits will limit REC liquidity by requiring more MW to be contracted for under long-term contracts, thus taking more RECs out of any potential market and resulting in lower liquidity and more volatile REC prices. This problem is illustrated by the following example:

> Under the current requirement, in order for an LSE to count short-term (less than 10 years) renewable purchases towards its annual RPS obligation, the LSE is required each year to enter into long-term contracts (10 years or greater) with existing renewable facilities (online date prior to January 1, 2005), or short/long-term contracts to purchase from new facilities (online date on or after January 1, 2005), such that total deliveries over the life of the contract are greater than 0.25% of the LSE's prior year's retail sales.
>
> If an ESP's prior year retail sales are 10,000,000 MWh, then 0.25% of this is 25,000 MWh:
>
> 10,000,000 * 0.25% = 25,000 MWh
>
> Under the current requirement, the ESP must enter into a long-term contract that will deliver at least 25,000 MWh over the term of the contract.
>
> If an ESP contracts with a 0.3 MW geothermal plant that has a 96% capacity factor, then each year the plant will deliver 2522.8 MWh annually:
>
> 0.3 MW * 8760 hrs/year * 0.96 = 2522.8 MWh/year
>
> Over the course of 10 years, the plant will deliver 25,228 MWh, which will fulfill the 0.25% requirement for that year.

If a contract or contracts signed that year has an expected delivery that exceeds the minimum requirement for that year the excess may be "banked" forward to meet future years' obligations. The current requirements, including banking provisions, provide a very clear and clean way to track an LSE's compliance with this obligation.

On the other hand, under the proposed change, the ESP must deliver 25,000 MWh every year to meet the 0.25% requirement. Therefore, instead of contracting for 0.3 MW, the ESP would need to contract for 3 MW to meet that year's delivery requirement, which would be 25,228 MWh:

8.760 hrs/yr * 3 MW * 0.96 = 25,228 MWh/year

Under the current rules, if there are 4 MW of non-contracted power available, after the ESP signs a long-term contract for 0.3 MW of capacity, there will still be 3.7 MW of RECs to be generated from that plant. Under the proposed rules, if there are 4 MW of non-contacted power available, after the ESP signs a long-term contract for 3 MW of capacity, there will only 1 MW equivalent of RECs left to be generated from that plant.

SUMMARY	MW available	MWh/yr equivalent	MW contracted	MWh/yr contracted	MWh/yr of RECs left
Current Rules	4	33,639	0.3	2,523	31,116
Proposed Rules	4	33,639	3	25,228	8,410

Having fewer RECs available in the market makes the market less liquid. REC prices will be higher because of a smaller supply, and subject to more volatility. In addition to potentially decreasing the supply of RECs in the marketplace, changing this requirement to an annual delivery requirement makes it unclear how the banking of excess procurement would work. For ESPs, it is critical to have the ability to bank forward excess new generation or long term-contracted resources to meet this trigger. ESPs have smaller loads that are potentially more volatile and as ESPs look to meet their 2010 RPS obligations, and ESPs are evaluating making more significant procurements—many of them with developing resources. Changing the way this trigger requirement is structured and calling for an annual delivery requirement makes it unclear how ESPs contracting for developing resources would help them have the ability to also

use short term contracts or REC procurements to complete our RPS compliance purchases. It also creates a disincentive for ESPs to enter into contracts with developing resources, as simply long term contracting with existing resources would be a "cleaner" way of meeting the annual delivery requirement. For all LSEs to meet their RPS compliance obligations, the state needs significant investment in new resources. Any additional complication or confusion in the rules surrounding RPS compliance obligations will only serve to frustrate the state's important goal to have new resources constructed and will severely hamper small LSEs' ability to meet the 20% renewables goal by 2010.

(3) In order to evaluate the cost recovery section of the straw proposal, please comment on whether, if authorized by the Commission, an unbundled REC market for RPS compliance should be viewed as a commodity market, in which prices converge and each unit does not have a different intrinsic value?

<u>If no:</u>

- **Is the value of an unbundled REC:**

  i. correlated to the production cost of the underlying renewable energy?
  ii. the price difference between a bundled renewable energy contract and a bundled fossil contract?
  iii. other?

No, it is not positively correlated, nor negatively correlated to the production cost. It reflects the societal preference for that particular renewable resource. The production cost of the underlying renewable energy will be reflected in the price that such facility commands for the commodity energy. For example, it is likely that the REC price for solar will be higher than the REC price for biomass. However, the marginal production cost for solar is $0, since there is no fuel cost, whereas the production cost for biomass will reflect the cost of the fuel, and the higher operating costs of the biomass plant. Currently, many renewable contracts for RPS resources consist of index energy prices plus a renewable adder. The renewable adder is essentially the

value of the REC. Thus, today's markets price the renewable value separately, with some resources more or less highly valued depending on market demand and technology preference.

If yes:

- **What factor(s) influence the commodity market price?**

The RECs will turn into a commodity market price over time, as the large buyers will seek to purchase RECs at the lowest price possible. As there is no carve-out for specific technologies in the California RPS, all RECs will have equal value to the buyer, which is the lowest price possible. However, there also exists a voluntary market for RECs, where buyer preference for certain technologies or location of resources will cause the REC prices to vary.

- **What methodologies can be used to evaluate the reasonableness of a REC price from the ratepayer's perspective?**

No comment.

- **Could the Commission practically implement the above proposed methodology? If not, what is the next best alternative approach?**

No comment.

(4) Please identify any aspects of the straw proposal that you consider unnecessary or duplicative, and briefly explain the basis of your views.

First, as explained in the example above, we believe the TREC Usage Limits that impose an additional requirement that expected deliveries during the compliance year must by 0.25% of the prior year's sales is unnecessary and will be damaging to any emerging TREC market. Utilizing the same "trigger" for new generation purchases or long term contracting as is required for the use of short term contracts in RPS compliance is a simpler cleaner way of achieving the underlying goal of this element of the proposal.

Second, as explained previously, the Earmarking restriction is unnecessary and adds needless complications to the market by hampering the ability of an LSE that wants to procure RECs separately from energy.

Third, regarding Treatment of Bundled Contracts, the Staff's proposal to delay use of tradable RECs until January 1, 2009 is completely unnecessary, as the required tracking and verification system to prevent any double counting is already in place now that WREGIS is operational.

(5) What elements, if any, in addition to those identified in the straw proposal would be necessary to create a market for tradable RECs and administer an RPS program that included tradable RECs, while advancing the goals of the RPS program and complying with the requirements of § 399.16? Please be specific and explain why each additional element would be necessary.

The straw proposal should specifically state that RECs from qualifying renewable DG projects are eligible for use for RPS compliance, and that these RECs can be used immediately, as discussed earlier in these comments.

(6) As noted in the Amended Scoping Memo, after a workshop on REC trading for RPS compliance, the parties will then have the opportunity to "comment on the desirability, or lack thereof, of adopting a system like one of those developed through the workshop process, or be able to make another proposal that could be contrasted in some detail with the previous possibilities." (pp. 4-5.)

(a) If the straw proposal were adopted as set forth in Attachment E, would you recommend that the Commission authorize REC trading as a compliance tool for RPS compliance?

We would recommend the straw proposal for REC trading be implemented in a fashion substantially similar to that outlined in the straw proposal but enhanced with the changes regarding TREC Usage Limits, Earmarking, and Treatment of Bundled Contracts that we have noted previously.

(b) If you would not recommend that the Commission authorize a REC trading regime as outlined in the straw proposal, please either develop an alternative REC trading proposal, or state and explain that your view that no REC trading regime would be satisfactory.

See response to previous question.

3. REC Attributes

(1) With respect to biogas that is an RPS-eligible resource, should the benefits of capturing methane in the production of the biogas be included in the attributes of the REC associated with the biogas?

AReM reserves comment on this issue.

(2) How should the "net zero emissions" requirement in the last sentence of the Green Attributes definition in Attachment D-2 be applied to the capture of methane to produce RPS-eligible biogas?

AReM reserves comment on this issue.

(3) Should a REC include avoided carbon emissions associated with conventional generation displaced by the renewable generation giving rise to the REC? As a policy matter, why or why not? Please include all factual information necessary to support the policy choice expressed. Identify any assumptions or predictions about AB 32 that are related to the policy preference expressed (e.g., "In a load-based regulatory framework in which emissions reductions from RPS compliance are included in the cap...") Please also make clear what definition of "avoided emissions" is being used in the response.

No, a REC should not include avoided carbon emissions as an attribute. There are two basic problems with this approach. First, avoided emissions is an inappropriate metric for a GHG attribute; *if* a GHG attribute is included with a REC, the attribute should represent the actual, direct GHG emissions of the generator. Second, bundling of a GHG attribute with a REC would be problematic under a source-based or first-seller system, and would undervalue renewable generation under a source-based system.

Regarding the first problem, by definition avoided emissions represent emission reductions against a hypothetical counterfactual case. It is impossible to know with certainty

what power was displaced by renewable generation; for this reason, estimates of avoided emissions are inherently inaccurate. For a GHG trading scheme—whether source-based, load-based or first-seller—it is critical that emissions are known accurately and with a high-degree of confidence. Further, if an avoided emissions attribute is included with a REC, it will be necessary to add an equivalent quantity of emissions to the estimate of emissions from null power. Otherwise, overall system-wide emissions will be under-estimated. (See the examples in Kristin Ralf Douglas' presentation.) The need to compensate "avoided emissions" elsewhere in the system increases the administrative complexity of accounting for these emissions and the likelihood of error. For this reason, the appropriate GHG attribute for renewable generation is the actual, direct GHG emissions of the generator—not avoided emissions. However, as explained below, additional problems are created if GHG attributes are bundled with RECs

(4) In view of the current uncertainties associated with the implementation of AB 32, what are the potential pitfalls, if any, both for the RPS program itself and the interaction of RPS with potential GHG regulatory methods, of determining that a tradable REC used for compliance with the California RPS includes avoided carbon emissions? Of determining that a REC does not include avoided carbon emissions? In responding to this question, please review the presentation on Carbon Market and REC Market Interactions made by Kristin Ralff Douglas at the workshop, but note that the examples in that presentation are intended to be illustrative only, and do not reflect any determination that a particular method of implementing AB 32 has been developed.

As noted above, "avoided emissions" is an inappropriate metric in the context of a GHG cap and trade system. While a different emissions metric could be used (such as emission allowances or direct emissions of the renewable generator), bundling these GHG attributes with RECs will likely render RECs incompatible with future GHG cap and trade systems, and result in under-valuation of the renewable resource.

Under a source-based or first-seller GHG trading system for the electricity sector, emission allowances will be needed by electricity generators for compliance with the GHG cap.

In contrast, RECs will be needed by retail electricity providers for compliance with the RPS. To enable allowances to be used by generators, and RECs by retail providers, any emission allowances must be unbundled from the RECs.

Under a load-based system, the point of regulation for both the RPS and the GHG cap would be retail electricity providers. In this case, a GHG attribute—specifically, the actual direct emissions of the renewable generator—could be bundled with the REC since both could be used by retail providers for compliance purposes. However, this could reduce the combined value of the REC and the GHG attribute since demand for the REC and demand for the use of the GHG attribute may not be coincident (i.e., one retail provider may need RECs for compliance with the RPS, but not for the GHG cap and vice versa).

(5) Are there any potential legal impediments to or uncertainties about the implementation of the policy preferences you expressed in response to questions 1-4? What are they? How might they be overcome? Please explain in detail.

As noted in our pre-workshop comments, the design and implementation of a California GHG cap and trade system under AB 32 is highly uncertain. While decisions may be made in the near future regarding the point of regulation under a cap and trade system for the electricity sector, the design of any federal or regional system cannot be predicted. Therefore, it is not advisable to prejudge the design of any of these systems, or the potential overlap of the REC market and GHG markets, as AReM and WPTF believe that any cap and trade system adopted for California must be easily integrated and transitioned to the regional or federal cap and trade system that is eventually adopted.

(6) Would particular decisions about the implementation of AB 32 alter your views about the issues discussed in Questions 1-5, above? What decisions would have an impact? What impact would they have? Why?

See responses to Questions 3 and 4 above.

4. Standard Terms and Conditions

(1) What changes, if any, should be made in the standard terms and conditions set forth in Attachment D-2 to reflect and/or accommodate the policy preference and legal analysis set forth in your responses to questions 1-6 in Section 3?

As noted in the response to question 3(4) above, bundling of GHG attributes with RECs may be problematic. For this reason, the Standard Terms and Conditions should be modified to allow unbundling of the REC and any GHG attribute. See the specific recommendations below.

(2) What changes, if any, should be made to the standard terms and conditions to accommodate the use of tradable RECs for RPS compliance, even if you think no other changes are required in response to the questions in Section 3, above?

Item 3.4 of the Standard Terms and Conditions should have a check box for two alternatives: One alternative is that found in both Attachments F-1 and F-2. The second alternative would state: "Seller hereby does not provide or convey any Environmental/Green Attributes from the Unit . . .", as shown below:

Check one:
3.4 Environmental Attributes:
- ❑ *Seller hereby provides and conveys all Environmental Attributes . . .*
- ❑ *Seller does not provide or convey any Environmental Attributes . . .*

Or

Check one:
3.4 Green Attributes
- ❑ *Seller hereby provides and conveys all Green Attributes . . .*
- ❑ *Seller does not provide or convey any Green Attributes . . .*

(3) What changes, if any, should be made to the standard terms and conditions to conform to Pub. Util. Code § 399.14(a)(2)(D), which provides in part that "A contract for the purchase of electricity generated by an eligible renewable energy resource shall, at a minimum, include the renewable energy credits associated with all electricity generation specified under the contract."

See response to the previous question.

(4) If any changes at all should be made to the standard terms and conditions, how should the RECs be treated that are associated with energy delivered under contracts using

(a) the standard terms and conditions set forth in Attachment D-1, or

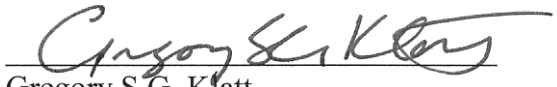
(b) the standard terms and conditions set forth in Attachment D-2?

See the response to the previous question, in regard to Attachments F-1 and F-2 in the ALJ's Ruling Requesting Post-Workshop Comments on Tradable Renewable Energy Credits.

D. CONCLUSION

In light of the many benefits of RECs and REC trading and the other considerations discussed above, AReM and WPTF strongly urge the Commission to allow the use of tradable RECs, including RECs associated with renewable DG, for purposes of RPS compliance. In addition, AReM and WPTF urge the Commission to amend the Staff straw proposal as discussed herein. AReM and WPTF thank the Commission for its attention to these comments.

Respectfully submitted,



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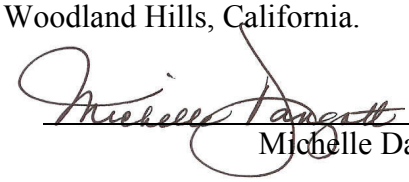
ALLIANCE FOR RETAIL ENERGY MARKETS AND THE WESTERN POWER TRADING FORUM

Date: November 13, 2007

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of **Post-Workshop Comments of the Alliance For Retail Energy Markets and the Western Power Trading Forum on Tradable Renewable Energy Credits** on all parties of record in proceeding **R.06-02-012** by serving an electronic copy on their email addresses of record and by mailing a properly addressed copy by first-class mail with postage prepaid to each party for whom an email address is not available.

Executed on November 14, 2007, at Woodland Hills, California.



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