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California Energy Commission
Dockets Office, MS-4
Re: Docket No. 11-RPS-01
and
Docket No. 02-REN-1038
1516 Ninth Street
Sacramento, CA 95814-5512

Re: <u>Renewables Portfolio Standard; Comments of Pacific Gas and Electric Company on the Staff Draft Renewables Portfolio Standard Eligibility Guidebook, 7th Edition</u>

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments on the Staff Draft Renewables Portfolio Standard ("RPS") Eligibility Guidebook, Seventh Edition (the "Draft Guidebook") issued by the California Energy Commission ("Commission") on March 12, 2013.

## I. INTRODUCTION

PG&E supports the Commission's ongoing efforts to implement the RPS in ways that ensure the integrity and cost-effectiveness of the program for all market participants. In particular, PG&E supports the Commission's work to update the Draft Guidebook to implement recent legislative changes to the RPS. These comments focus on a limited number of areas in which PG&E urges the Commission to reconsider or clarify the Draft Guidebook, including:

(1) Retaining the past practice of allowing utility-certified facilities to remain so certified until they expire or are materially amended;

(2) Adopting an alternative tracking and verification system for the de minimis Renewable Energy Credits ("RECs") associated with surplus generation from net metered facilities;

(3) Allowing biomethane schedules to provide evidence of physical gas flows on common carrier pipelines;

(4) Clarifying that Portfolio Content Category ("PCC") 0 RECs (aka "count in full") must be generated by facilities that were RPS-eligible under the RPS Guidebook in effect at the time the procurement took place;

(5) Allowing procurement of prior-period RECs for use in the prior compliance period until July 1 of the year following the end of a compliance period;

(6) Adding a definition of "delivery path" as it relates to biomethane;

(7) Removing a requirement that investor-owned utilities ("IOUs") submit biomethane procurement contracts to prove that green attributes were conveyed;

(8) Allowing for determinations that POUs may sell RECs to retail sellers at the time that the sale transaction is executed, rather than only at the end of a compliance period;

(9) clarifying the requirement that PCC 1 and 2 products cannot involve resale to the generating facility; and

(10) other minor and typographical corrections as listed in the table in Attachment 1 to these comments.

## II. COMMENTS ON THE DRAFT GUIDEBOOK BY ISSUE

### A. A Requirement to Re-Certify All Utility-Certified Facilities by the End of 2013 is Unnecessary and May Conflict with Statute.

The Draft Guidebook proposes changes to the termination date of the RPS certification of facilities previously certified by a retail seller on behalf of a generator using a CEC-RPS-2 form.[1/] Retail sellers were able to certify facilities in this way before the publication of the fourth edition of the RPS guidebook. Prior to the current draft revisions, the RPS Guidebook consistently provided that except for California Public Utilities Commission ("CPUC")-ordered extensions to existing Qualifying Facility ("QF") power purchase contracts, a retail seller's certification on the operator's behalf using the CEC-RPS-2 form terminates only in the event the facility's contract with the retail seller expires, is voluntarily extended, or is otherwise renegotiated by the retail seller and the facility operator. For CPUC-ordered extensions, retail seller certification may continue until the extension expires.

The current Draft Guidebook would change this long-established approach by requiring that such utility-certified facilities "must apply for ongoing certification on their own behalf using the CEC-RPS-1 form, on or before December 31, 2013, regardless of the initial contract termination date."[2/] The Draft Guidebook further states that "after December 31, 2013, the Energy Commission will suspend the RPS eligibility of all utility certified facilities if an

1/ Draft Guidebook at 98-99.
2/ *Id.* at 99.

application to certify the facilities on facility owner's behalf has not been submitted."[3/] Similarly, the Staff presentation on March 14, 2013 suggested that the Draft Guidebook would require all existing biomethane facilities (including, presumably, legacy QF facilities for which a utility-certification had been submitted) to re-apply for certification within 90 days of the adoption of the Draft Guidebook.[4/]

These new requirements are problematic since all PG&E's utility-certified facilities provide energy pursuant to legacy, standard-form QF Power Purchase Agreements ("PPAs"), which do not explicitly require the seller to apply for or maintain RPS certifications. Since QFs are under no explicit obligation to apply for or maintain an RPS certification, this abrupt change in Commission rules places the QF portion of PG&E's RPS historic baseline at significant risk of de-certification. Moreover, to the extent the policy results in generation from such legacy QF contracts not being eligible to count toward PG&E's RPS procurement obligation, the Draft Guidebook would create a potential conflict with California Public Utilities Code Section 399.21(a)(4), which provides that for PPAs executed before January 1, 2005 that do not contain explicit terms and conditions specifying the ownership or disposition of renewable energy credits ("RECs"), the output "shall be…included in the quantity of eligible renewable energy resources of the purchasing retail seller" for purposes of RPS compliance.[5/] Many, if not all, of PG&E's utility-certified facilities fit within the category described in Section 399.21(a)(4).

During the March 14, 2013 workshop held by the Commission on the Draft Guidebook, Commission Staff explained that they had proposed this change because there was perceived uncertainty about when legacy QF contracts would expire and resulting concern that facilities would fail to re-certify on a timely basis when they signed a new or amended contract. PG&E shares this desire to ensure that its legacy QF facilities continue to remain RPS-certified. Toward that end, PG&E has provided to Commission Staff the expiration dates for its existing utility-certified facilities. Additionally, PG&E intends as a courtesy to its counterparties to provide notice and re-certification information to its QFs one year in advance of the year in which they expire. PG&E believes that these steps, taken as a whole, sufficiently reduce the risk of loss of certification and the administrative burden on all parties. Accordingly, the requirements to re-certify all utility-certified facilities (including utility-certified biomethane facilities) should be removed, and the existing policy of preserving utility-certifications until contracts expire or are amended in the specified ways should be retained.

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3/ *Ibid.*

4/ Staff Presentation, Slide 60.

5/ Cal. Pub. Util. Code § 399.21(a)(4) (emphasis added).

**B. The Requirement to Track the RECs Associated with Excess Generation from Net-Metered Facilities through WREGIS Remains Too Burdensome and Will Likely Eliminate the Ability of Many Distributed Generators to Participate in the RPS Program.**

PG&E appreciates the challenges the Commission faces in tracking and verifying RECs associated with excess renewable generation from Net-Metered Facilities under the Assembly Bill ("AB") 920 program. PG&E supports the Commission's proposal to allow AB 920 facilities to apply for certification as an aggregated unit on the CEC-RPS-3 application form.[6/] However, the proposed requirement that all facilities applying for certification as an aggregated unit on the CEC-RPS-3 application form must also register in WREGIS as an aggregated facility and share a WREGIS Generating Unit ID number (GU ID) is impractical and will likely eliminate the ability of most AB 920 generators to participate in the RPS program.

While this linkage between the RPS ID and WREGIS GU ID may work for a relatively static population of distributed generation facilities reporting their entire output, this is impractical for generators under the AB 920 program, which features minor amounts of excess generation from a large and quickly expanding number of customers. For perspective, PG&E's AB 920 program currently has nearly 80,000 customers and is growing at a rate of 1,200 to 1,500 customers each month. About 8-10 percent of PG&E's AB 920 customers have excess generation each year, although the specific customers with excess generation changes from one year to the next. PG&E has investigated the practicality of aggregating AB 920 customers under the Commission's proposed method and determined that it would likely not be cost-effective for PG&E to register these aggregated resources in WREGIS given the small amounts of excess generation per customer. The alternative of AB 920 customers registering themselves in WREGIS is also not cost effective due to the $200 minimum annual fee per account, and the extremely small amount of net generation exports for most accounts. PG&E's net metered customers have not been, and likely will not be, able to take full advantage of the provisions of AB 920 designed to provide them compensation for their RECs because of the way the Commission has implemented the bill to date.

At the Commission workshop on March 14, 2013, PG&E indicated it would be offering a counter proposal that would be more streamlined and cost effective. PG&E proposes to register its AB 920 customers using CEC-RPS-3 application form, as described in the Draft Guidebook. However, since PG&E's AB 920 population grows each day, PG&E proposes to amend its CEC-RPS-3 aggregated unit once every three months, rather than within 30 days as proposed in the Draft Guidebook, to reduce the administrative burden on all parties. To report excess generation, PG&E proposes not to use WREGIS, but rather to report such excess generation to the Commission directly from its customer billing system used to track and pay AB 920 customers for their net surplus generation each year (the "Net Surplus Generation Report"). Because some AB 920 customers do not receive the RECs associated with their generation under the contractual arrangement with the company that installed their facility, a method would need to be

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6/ Draft Guidebook at 96-97.

developed to verify which AB 920 customers can convey the RECs from their facilities, and PG&E will only report net surplus generation from those customers. In PG&E's Net Surplus Generation Report, PG&E will provide information to enable the Commission to cross-reference the facility with the CEC-RPS-3 aggregated unit. PG&E proposes that the excess generation amounts reported to the Commission from its customer billing system, once verified by the Commission, will be eligible for inclusion as RPS-eligible deliveries in PG&E's RPS Verification Report. PG&E proposes that the Commission limit the availability of this tracking and verification method to only net-metered facilities under an AB 920 program and only for those facilities exporting less than 30,000 kWh per year (i.e., 30 MWh).

Using the auditable method described above to track and verify de minimis levels of generation from AB 920 customers[7/] will allow this generation to participate cost-effectively in the RPS program and will provide the full value of the generation to PG&E's customers while also allowing the Commission to comply with statutory requirements.

### C. The Guidebook Should Clarify that Gas Schedules Are Adequate Evidence of Physical Flows.

While PG&E appreciates the Commission's continued efforts to engage the public in the implementation of AB 2196, the Draft Guidebook's requirement that applicants demonstrate movement of out-of-state, common carrier biomethane toward California through physical flow measurements remains unnecessarily burdensome and likely unworkable.[8/] The result of adopting this proposed standard will be to severely restrict, if not effectively bar, out-of-state biomethane producers from participating in the California RPS.

The Draft Guidebook would require PG&E to "provide documentation . . . to demonstrate that the pipeline [used to transmit the out-of-state gas to PG&E's facility] meets [the 50% flow requirement] by providing verification from the transporting carrier pipeline regarding the physical flow of the pipeline(s)."[9/] PG&E cannot guarantee that it would be able to provide this type of documentation since pipeline operators may only publicly post information related to scheduled flows. Physical flow information, to the extent it is available at all, may only be available to the direct customers of the pipeline company through proprietary, electronic bulletin boards (this is the case, for example, on the El Paso pipeline system).

Even if physical flow information were readily and publicly available, PG&E submits that the scheduled, or nominated, volumes of gas should provide adequate evidence of physical flows since the two are highly correlated. While actual physical flows may temporarily diverge from scheduled flows between pipelines due to unanticipated congestion such that a delivering pipeline may over- or under-deliver, the over- or under-delivery is generally corrected in a relatively short time period so that both pipelines can remain in balance. Thus, over time, and

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7/ The CPUC found that the AB 920 generation in PG&E's system was de minimis, representing only 0.04% of PG&E's annual RPS target for 2009. D.11-06-016 at 42, fn. 24.

8/ *See* Draft Guidebook at 32.

9/ *Ibid.*

particularly on an annualized basis, the schedule of flows on a pipeline will correspond to the actual direction of flow. In order to reduce the burden on the regulated entities and in recognition of the inability of applicants to demand or compel pipeline operators to provide physical flow data, the Commission should recognize that scheduled flow data may be presumed to correlate with and provide sufficient evidence of the physical flows on an annualized basis.

Allowing scheduling data to be used rather than physical flow data also ensures that the biomethane industry is treated similarly to other forms of RPS-eligible generation. Under the Draft Guidebook, generators of electricity are not required to provide documentation that actual electrons are transmitted in real-time into California in order to qualify as Product Content Category 1, but rather are allowed to submit schedules and e-Tags showing that a contractual arrangement guarantees a delivery path into California.[10/] This verification criterion recognizes the reality that the actual electrons, like gas molecules, will follow the law of physics at any given moment, and that attempting to trace the actual physical particles into California is not feasible. Instead, the Guidebook recognizes that contract paths provide sufficient proxies for the actual flow of electricity since the two must balance over time. The Commission should take the same approach with biomethane, and may do so in full compliance with AB 2196 if it finds that the schedules are sufficiently correlated with physical flows over time.

Generally, all gas volumes flowing in the various pipeline systems are scheduled in advance on a daily basis, using each pipeline's nomination and scheduling systems. Daily nomination and scheduling records from the out-of-state facility to the California border should be considered acceptable evidence documenting the flow of biomethane to California. If those scheduling records demonstrate that in the year prior to the submission of the application for certification, the gas flowed from the biomethane generation facility toward California more than 50 percent of the time, then the resource should meet the Draft Guidebook's criterion, at least for some initial period of a long-term contract. Separately, for purposes of verifying the RECs, tracking of the renewable gas volumes can be accomplished after-the-fact through submission of documents showing the pipelines along which the biomethane was scheduled, from its source (and initial pipeline injection) through to the end user of the gas.

### D. "Count In Full" Procurement Need Only Be Generated By a Resource That Was RPS-Eligible at the Time Executed.

The RPS statute provides that in order for a contract or ownership agreement to count in full toward the RPS compliance requirements, without regard to the Product Content Category and the excess procurement rules, the "renewable energy resource" must have been "eligible under the rules in place as of the date when the contract was executed."[11/] Revisions in the Draft

10/ *See* Draft Guidebook at 131 *et seq.*
11/ Cal. Pub. Util. Code §399.16(d)(1).

Guidebook would interpret this as requiring such grandfathered facilities to have met the "contracting and delivery rules" in place in the Guidebook at the time of execution.[12/]

The Draft Guidebook would go beyond the straight-forward statutory question of whether the resource, or facility, was eligible to be RPS-certified under the Guidebook eligibility rules in place at the time of execution. It would also require review of the contract or agreement itself to determine consistency of the provisions, including the delivery structure, with contracting and delivery rules. The Draft Guidebook change leaves unclear whether such rules are limited to those in the Guidebook at the time, or would also involve a review of rules established by other state agencies like the CPUC.

The Commission should not expand the inquiry beyond the eligibility of the facility that generated the RECs. Limiting the interpretation to the status of the facility is most in line with the plain statutory language requiring the "renewable energy resource" – not the contractual or delivery arrangements – to be eligible. PG&E's proposed interpretation is also consistent with existing language carried forward in the Draft Guidebook, which requires that the "facility" (not the contract or delivery arrangement) be "eligible for the RPS under the rules in the *RPS Guidebook* as of the date when the contract was executed."[13/] The Commission should maintain its prior approach, which is consistent with the statute.

### E. LSEs Should Be Able to Procure Prior-Period RECs and Use Them for Prior-Period Compliance Until the Compliance Reporting End-Date.

The Draft Guidebook would bar LSEs from retiring RECs for a reporting year prior to when the RECs were procured.[14/] Thus, for example, an LSE would be unable to procure 2013-vintage RECs in January 2014 and use them for compliance in the 2011-2013 compliance period.

Because nothing in the RPS statute requires this prohibition, and because it will tend to increase the cost of RPS implementation, the Draft Guidebook should be revised to allow LSEs to procure and retire RECs for use to comply with a prior compliance period up until the July 1 reporting deadline in the year following the end of the compliance period. This would allow an LSE to procure products to optimize the cost-effectiveness of its overall RPS procurement for a compliance period in accordance with the Portfolio Content Category rules. For example, until the compliance period ends and an LSE knows exactly the volumes of its retail sales, it will be relatively conservative with regard to procurement of PCC 3 products to ensure that it does not procure over the limits set forth in California Public Utilities Code Section 399.16(c). Once the compliance period ends and the retail sales are definitively established, the LSE should have an opportunity to optimize the mix of products to ensure that it is complying with the RPS requirements at the least cost for its customers.

12/ Draft Guidebook at 128.
13/ Draft Guidebook at 99.
14/ *See id.* at 121, 141.

### F. The Commission Should Define "Delivery Path" As It Relates to Common Carrier Pipeline Biomethane.

The Draft Guidebook would require applicants to ensure that any revisions to the "delivery path" for existing contracts for common carrier pipeline biomethane comply with the Guidebook in place at the time the revision occurs.[15/] Similarly, any change in the "pipeline delivery path" for biomethane procured as part of a new biomethane procurement contract must be reported to the Commission as part of an amended certification application within 90 days of the change.[16/] Given that these requirements hinge on changes to the "delivery path," the Commission should define that term in the Glossary to the Guidebook. Because the physical and contractual flow of gas may change frequently, but immaterially, over the course of a multi-year contract, PG&E recommends that "delivery path" be defined as consisting solely of a point of injection and an ultimate point of delivery.

### G. IOUs Need Not Be Required to Submit the Biomethane Agreement to the Commission To Prove Transfer of Green Attributes

The Draft Guidebook would require an applicant for certification of a biomethane facility to submit to the Commission a "copy of the biomethane procurement contract with the application to demonstrate that the environmental and renewable attributes associated with the biomethane are transferred to the facility."[17/] This requirement is unnecessary, and therefore burdensome given the complex procedures required to submit market-sensitive information, for IOUs under the jurisdiction of the CPUC since existing CPUC regulations adequately ensure the transfer of the environmental and renewable attributes. Specifically, the CPUC has ordered IOUs to include a non-modifiable standard term and condition in each RPS-eligible procurement contract that defines "Green Attributes" as including "any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants."[18/] The Green Attributes specifically include the RECs generated by the project.[19/] Additionally, the non-modifiable standard language conveys all such Green Attributes associated with all electricity generation from the project to the buyer as part of the product being delivered.[20/]

Because CPUC regulations already ensure that the environmental and renewable attributes associated with the generation of biomethane are transferred to the IOU/applicant, the Commission should allow IOUs to submit a resolution from the CPUC approving the procurement and confirming that all non-modifiable standard terms and conditions were included, rather than require submission of the procurement contract itself.

15/ Draft Guidebook at 30, 40.
16/ *Id.* at 33.
17/ *Id.* at 36.
18/ *See* CPUC Decision ("D.")08-08-028 at Appendix B.
19/ *Id.*
20/ *Id.*

### H. The Commission Should Verify the RPS-Eligibility of Proposed POU Sales of RECs to Retail Sellers at the Time of Procurement.

The Draft Guidebook adds a new section describing how it will evaluate whether a retail seller and POU have met the statutory criteria allowing a retail seller to use RECs for compliance that the retail seller procured from a publicly-owned utility ("POU").[21/] In the March 14, 2013 Workshop, Commission Staff stated that they would interpret this section of the Draft Guidebook to require that a POU first make a definitive compliance demonstration for a given compliance period before the Commission would issue a determination that RECs sold to a retail seller by that POU during the prior compliance period could be used by the retail seller for compliance.

The Commission's interpretation is inconsistent with the statute and will make trading of RECs between POUs and retail sellers prohibitively risky. First, the statute states that such trades may occur if the POU "is procuring" sufficient RECs such that it "will not fail" to meet the compliance requirements in the event that the sale to a retail seller is approved.[22/] This standard envisions a test that can be met at the present time of the REC sale transaction based upon projections of compliance. If the Legislature had intended the Commission's interpretation, it would have required that the POU "has procured" sufficient RECs and to show that it "did not fail" to meet its requirements, both of which would have been backward looking and rely on historical data. Instead, the statute is best read as requiring the Commission to evaluate the status of the POU's RPS compliance at the time of the transaction to determine, based upon a Renewable Net Short ("RNS") calculation, which should take into account reasonable project failure rates, whether the POU is projected to comply with the compliance period requirements without the RECs. If the POU has both adopted a procurement plan and has a RNS that demonstrates compliance without the RECs, the Commission should approve the transaction as irrevocably eligible under Section 399.31 to be used for the retail seller's RPS compliance. Additionally, the Draft Guidebook should be revised to commit the Commission to issuing such a determination within a short period of time, perhaps 15 days, of the POU submitting a complete RNS and the sale contract. This will allow the sale contract to become effective in a reasonable period of time.

### I. The Draft Guidebook Should Clarify that PCC 1 and 2 Transactions Cannot Involve a Sale of the Energy Back to an Entity That Owns or Operates the Generating Facility.

The Draft Guidebook provides that for both PCC 1 and 2 transactions, POU verification will require documentation concerning the resale of the transaction.[23/] Specifically, with regard to PCC 1 transactions, the Draft Guidebook states that POUs must show "[t]hat there was no resale of the electricity back to the facility."[24/] Because LSEs have no control over the downstream energy transactions that take place after they take delivery of energy into CAISO or

21/ Draft Guidebook at 142.
22/ Cal. Pub. Util. Code § 399.31(b).
23/ Draft Guidebook at 129, 139.
24/ *Id.* at 129.

sell the energy to another market participant, the Commission should clarify that the requirements not to resell energy to the "facility" means that a POU cannot include in its procurement contract any provision that immediately sells back the procured energy to the specific corporate entity that owns or operates the generation facility. Thus, a POU should be able to sell energy in a PCC 2 transaction to a firming and shaping services provider that is affiliated with the corporate entity that owns or operates the generator, so long as the energy is not sold by the POU to the generation owner/operator itself. Additionally, the POU should not have to document the ultimate disposition of the energy (including any subsequent resale transactions), since doing so would be commercially unreasonable, if not infeasible.

### J. The Commission Should Make Other Minor Changes to Correct Typographical and Other Obvious Errors.

Attachment 1 to these comments provides a list of minor typographical and other apparent corrections that should be made in the final edition of the Draft Guidebook.

## III. CONCLUSION

PG&E appreciates the opportunity to provide comments on the Draft Guidebook and looks forward to continuing to work with the Commission to finalize the Draft Guidebook consistent with the recommendations set forth above.

Best regards,

*/s/*

M. Grady Mathai-Jackson

cc: Paul Douglas, CPUC, via E-mail at psd@cpuc.ca.gov
Sean Simon, CPUC, via E-mail at sean.simon@cpuc.ca.gov

## ATTACHMENT 1: LIST OF TYPOGRAPHICAL AND OTHER MINOR CORRECTIONS

| Page | Line | Change Required |
|---|---|---|
| 18 | Last | Of a facility ~~mens~~ means |
| 19 | 3 from top | “RPS eligible” or “RPS certified.” |
| 28 | 14 from bottom | The Energy Commission ~~both~~ before March 29, 2012 |
| 33 | 19 from top | biomethane injections ~~must be considered~~. |
| 34 | Last paragraph | If the requirements of this guidebook are satisfied, the procurement of electricity products claimed by a retail seller or POU from an electrical generation facility using biomethane is eligible to count toward the RPS procurement requirements. ~~in place at the time the biomethane procurement contract was executed by a retail seller or POU.~~ [**Note**: This language is inconsistent with the remainder of the Guidebook, which allows existing, qualifying biomethane contracts to count toward current and future RPS procurement requirements.] |
| 35 | Subparagraph c near bottom of page | Both the biomethane procurement contract and PPA were executed before June 1, 2010~~, and the biomethane procurement contract provided for deliveries of biomethane to the designated electrical generation facility for generation before June 1, 2010~~, then the procurement . . . . [**Note**: The deleted language is inconsistent with |

| | | |
|---|---|---|
| | | Section 399.16(d).] |
| 57 | Middle of Table 2, first column | Interconnected to a non-CBA ~~Outside CA~~ [Note: can be interconnected to a non-CBA within CA. Requires global change – language recurs at bottom of p. 71 and in several places from p. 74 to p. 79] |
| 99 | Footnote 119 first line | Less than 90 days before |
| 108 | 4th bullet, second line | Facility may ~~me~~ be claimed |
| 118 | Throughout | Heading numbering is off beginning with "Transitioning to WREGIS for POUs" |
| 131 | 11th line from top | Dynamically ~~scheduled~~ transferred into a CBA [**Note**: dynamic transfers include both dynamic scheduling for dispatchable resources and pseudo-tie arrangements for intermittent resources.] |
| 139 | Middle of page | Section VI.C.1.3: Facilities with a First Point of Interconnection outside a CBA ~~– Scheduling Generation into a CBA~~ – Scheduling Generation into a CBA, |
| 141 | 3rd line under subsection 3 | Requirements of either PCC 0, PCC 1, or PCC 2 |
| 151 | Dedicated pipeline – 3rd line | Generation facility ~~a~~and to no other |
| 156 | Portfolio Content Category | Refers to one of the three categories of electricity products procured from an eligible renewable energy resource, as such categories are defined in Public Utilities Code Section 399.16, Subdivision (b). |