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

Re: Renewables Portfolio Standard: Comments of Pacific Gas and Electric Company on the Proposed Changes to the *Renewables Portfolio Standard Eligibility Guidebook* and the *Overall Program Guidebook for the Renewable Energy Program*

I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") appreciates the opportunity to provide comments on the California Energy Commission's ("CEC") proposed changes to the Renewables Portfolio Standard ("RPS") Eligibility Guidebook ("RPS Guidebook") and the Overall Program Guidebook for the Renewable Energy Program ("Overall Guidebook"). PG&E's comments focus on seven issues: 1) the CEC should not modify certain definitions in the Overall Guidebook prior to conclusion of the 2011 IEPR; 2) there is a need to continue to pre-certify RPS eligible facilities so that their test energy can be counted toward the state's RPS goals; 3) limited use of the Interim Tracking System should continue to ensure accurate Renewable Energy Certificate ("REC") allocations; 4) some clarifications are needed in the discussion of the 33% RPS program targets; 5) the aggregated facilities application process is appropriate and should proceed, but should not be applied to the AB 920 program; 6) clarify de minimis fossil fuel use language to allow up to a de minimis level of nonrenewable fuel use to count as renewable energy and 7) other process clarifications are needed. PG&E is happy to discuss these comments with the CEC staff should additional information be needed.

II. KEY DEFINITIONS IN THE OVERALL GUIDEBOOK SHOULD REMAIN UNCHANGED

In the Overall Guidebook, several changes are indicated to the "Glossary of Terms" beginning on page 19. In particular, new definitions are set forth for "Balancing Authority Area", "California Balancing Authority", "Central Station Facility", "Distributed Generation Facility", "Distribution Network", and "Localized electricity generation facility". Modification of these definitions is premature and should not be made at this time.

First, the CEC's 2011 Integrated Energy Policy Report ("IEPR") is considering many issues, including how "Distributed Generation Facility" and "Localized electricity generation facility" should be defined for purposes of implementing the Governor's 12,000 MW of localized energy resources plan. Updating these definitions now in the Overall Guidebook will unnecessarily duplicate issues already being considering in the IEPR process and create confusion among parties who may not have received adequate notice that definition of these key terms was being considered at this time in the Overall Guidebook updates. Moreover, updating the Overall Guidebook before conclusion of the IEPR process creates the possibility of conflicting definitions and corresponding confusion within the industry. PG&E's October 5, 2011 comments in the 2011 IEPR contain proposals for how some of these terms could be defined and PG&E incorporates those proposals herein by reference.

Second, the California Public Utilities Commission ("CPUC") is currently considering how to define key terms to implement the 33% RPS requirement, including definitions of California Balancing Authority or Balancing Authority Area. Once the CPUC has defined those terms, the CEC should then update these definitions. To update these definitions prior to issuance of a CPUC final decision would be premature and create potential unintentional conflict with CPUC definitions.

Lastly, it appears that the modifications to the "Central Station Facility", "Distributed Generation", "Distribution Network" and "Localized electricity generation facility" may be driven by a desire to specify what types of facilities are interconnected to the transmission system and distribution system. While well-meaning, PG&E believes such distinctions are not necessary and such artificial distinctions will create confusion and inconsistent policies across utilities. For example, as noted in the definition of "distribution network", each IOU's energy delivery network may have different voltage cut-offs for what is regulated as the "transmission network" and the "distribution network". However, the entire network is needed to deliver energy to customers. Such a definition, when combined with the proposed definition of "distributed generation" would result in generation in PG&E's service territory that is interconnected at 115 kv would be considered a "Central Station Facility", while in SCE's territory, it would be considered a "Distributed generation facility." Such an outcome will create an unworkable policy framework and complicate the analysis of what counts towards various policy goals. While PG&E opposes any modifications to the existing definitions given

the IEPR is considering these issues, PG&E also opposes such arbitrary definitions that will only further complicate California's energy policy planning.

III. PRE-CERTIFICATION OF RPS FACILITIES SHOULD CONTINUE

In Attachment B to the CEC's Revised Notice of Staff Workshop, the Energy Commission staff seek stakeholder input on whether pre-certification should be continued and, if so, what improvements should be made. The CEC should continue to provide pre-certification for new RPS-eligible facilities as it provides substantial benefits to the RPS program.

Pre-certification is an important factor in promoting the development of new renewable resources. Pre-certification allows developers more certainty that the proposed project will be RPS eligible, which is a critical factor in obtaining financing and successful negotiations of power purchase agreements. Pre-certification also is critical to allow new generating facilities to receive RECs for test energy. Without pre-certification there might be ambiguity as to the eligibility of test energy.

Some modifications to the pre-certification process could balance the need for and benefits of pre-certification with reasonable restrictions. For example, if a facility has not applied for certification within five (5) years of the pre-certification submission, then it would be reasonable for the Energy Commission to require a project to reapply for pre-certification. The passage of five (5) years is likely to indicate that the project is not proceeding or that the project has undergone significant modifications in scope or technology, which could impact RPS eligibility.

In order to receive pre-certification, an applicant should have to demonstrate reasonable milestones in order to ensure that pre-certification is warranted. On the other hand, such milestones should not be overly onerous, as requiring near-completion of the development process would frustrate the benefits and goals of pre-certification. For example, a reasonable milestone would be the demonstration of site control in the interconnection process. Not only would this provide the Energy Commission with necessary details to support pre-certification (*e.g.,* the project's location), but site control is reasonable evidence of the commitment of the project developers. In contrast, requiring approval of all permits could delay pre-certification unnecessarily to the point of impeding the financing of the project.

IV. LIMITED USE OF INTERIM TRACKING SYSTEM SHOULD BE ALLOWED

At pages 106 through 109 of the RPS Guidebook, the CEC proposes to eliminate use of the Interim Tracking System ("ITS") for retail sellers as of the 2011 verification year and for POUs as of July 1, 2012. In order to ensure that all renewable generation is correctly accounted for in the reporting process, however, there is a critical need for continued flexibility for RPS tracking. Notwithstanding that WREGIS staff and industry participants have developed and

implemented a robust and commendable tracking system, there are inherent limitations in the WREGIS system that result in discrepancies between WREGIS certificates and actual generation and delivery of renewable energy. In such cases, the Interim Tracking System should be allowed as an exception to the general rule.

For example, the following situations warrant flexibility in reporting mechanisms:

- Test energy generated prior to the active certificate issuance cycle at the time certification of a new generating facility is complete. As acknowledged by the RPS Guidebook at page 108, the WREGIS system only creates RECs for generation associated with the earliest active certificate issuance cycle at the time the facility is approved in the WREGIS system. In other words, WREGIS will only create RECs for test energy that is generated within 75 days of when the new facility is approved. Testing of a new generating facility, however, may take place beyond 75 days prior to commercial operation. Depending on when in the certificate issuance cycle the facility reaches commercial operation, and when the WREGIS approval is complete, months of test energy for a new generating facility could fall outside of the WREGIS certificate issuance cycle and therefore not receive REC certificates. In 2010, PG&E procured renewable energy from two different counterparties that experienced WREGIS Certificate shortfalls for generation during each facility's test energy period.

- In addition to the potential loss of certificates during test energy periods, PG&E has observed that several RPS contract counterparties starting up during compliance year 2010 have experienced delays getting their projects approved in WREGIS. The delays have various causes, including an inability to secure a qualified reporting entity (QRE) and unfamiliarity with WREGIS registration procedures, particularly with smaller projects with fewer resources to dedicate to mastering the WREGIS Operating Rules. Projects face many hurdles during project start-up and adding the intricacies of WREGIS operations during that same time frame has proved to be challenging for some projects. In 2010, PG&E had procured renewable energy from two counterparties that experienced WREGIS Certificate shortfalls due to late registration in WREGIS caused by delays in securing a QRE.

- In addition to hurdles registering projects in WREGIS, there are questions about how large scale solar projects, phased in over a period of several years, will be registered in WREGIS. PG&E understands that WREGIS plans to require such phased in projects to register each installation phase as separate generating units. This duplicative requirement to register portions of such projects as separate generating units may lead to additional challenges in securing timely registration and approval in WREGIS and may also result in WREGIS Certificates shortfalls.

- WREGIS rules do not allow reductions in the quantity of issued certificates. The only method to correct the total quantity of certificates issued is to reduce the amount of certificates issued for future cycles by a corresponding amount (until the excess amount can be fully offset by the reduced creation of future certificates). This functionality constraint in WREGIS may lead to certificate vintages not corresponding to the correct year of generation. For example, if 100 excess certificates are created in December 2011, the only way to correct the excess is to reduce the number of certificates issued in future months by that amount. If generation in the first five months of 2012 averages 20 certificates per month, no certificates would be created for the first five months for that particular project. At the end of the 2012, that particular facility would have 100 too many certificates in 2011 and 100 too few certificates in 2012 (with the total amount for the two years being correct). This could result in unfair treatment if there are restrictions on the ability to retire certificates. Using the ITS could correct the situation by allowing the 100 GWH shortfall in 2012 to be reported with the ITS. The additional certificates for 2011 would then be set aside. Therefore, use of the Interim Tracking System is needed to allow for reconciliation of these differences to allow the corrected amounts to be reported in the year in which the generation occurred.

- WREGIS sets MWh limits for certificates created each month based on a designated annual average capacity factor or MWh ceiling. Many projects exceed these limits in various months due to the seasonality of renewable generation, resulting in certificates not being created. For example, if the assigned annual average capacity factor for a particular generator is deemed to be 30% and the generation during the particular month exceeds the project's capacity factor level, then all the generation for the month is considered to have failed technical feasibility. These exceeded generation amounts are typically overridden by the WREGIS administrator and the appropriate amount of WREGIS Certificates are created. There is no guarantee that all generation amounts considered to fail technical feasibility will be overridden, however, which places the generator at risk of having a shortfall of certificates created. Until WREGIS processes are changed to rectify this situation or the individual generator capacity factor or MWh ceilings are increased to a level sufficient to avoid exceeding estimates of technical feasibility, flexibility in using non-WREGIS reporting is needed to ensure that generation is counted correctly and in a timely manner. To put this into perspective for PG&E, out of 215 WREGIS Generating Units for which PG&E is the WREGIS asset manager, 95 of those generating units failed technical feasibility during the June 2011 certificate creation month. Should any of these units' generation exceed status not be overridden by the WREGIS Administrator, the interim tracking system would be the only means by which PG&E could obtain RPS credit for these RPS eligible deliveries of renewable generation.

- Certificate errors may become uncorrectable once the facility's WREGIS generator unit ID is transferred to another party. Once the ID is transferred, certificate errors attributable to generation periods preceding the transfer become uncorrectable. It is also

possible to lose certificates attributable to the generation period immediately preceding the transfer of a generating unit ID due to the three-month certificate creation process, which could extend into the period after which the generator unit ID was transferred. Until WREGIS functionality is changed to allow the transferring party more flexibility in correcting certificate errors for past periods or allows the party receiving the generating unit to create certificates more than 75 days prior to receipt of the generator unit ID, flexibility in using non-WREGIS reporting is needed to ensure that generation is counted correctly. In 2010, PG&E procured renewable energy from two RPS facilities which experienced WREGIS Certificate shortfalls as a result of certificate creation gaps incurred during the transfer of a generating unit ID.

These limitations to the WREGIS system may be eliminated in the future if system upgrades to WREGIS are made to allow the correction or creation of certificates for periods and circumstances beyond WREGIS' current capability. Until such time, however, PG&E recommends that the Energy Commission continue to allow the use of the Interim Tracking System on an exception basis to track and correct certificate allocations, beyond the currently proposed limitations. This will ensure a full and accurate count of each year of a retail seller's renewable procurement.

V. RPS PROCUREMENT TARGETS SHOULD BE CLARIFIED

At page 15 and continuing to the top of page 16 of the RPS Guidebook, an interpretation is provided of the RPS procurement targets for retail sellers that does not properly capture the legislative requirements of SB 2 (1x). PG&E recommends modification of the RPS Guidebook language to mirror the statutory requirements for the procurement targets. Alternatively the RPS Guidebook could rely upon a reference to the statute without summarizing the interim targets and other RPS compliance provisions such as banking. Additional modifications to this language will likely be required once the CPUC adopts interim procurement goals for retail sellers.

The three compliance periods and associated statutory targets are:

a) For the period January 1, 2011 to December 31, 2013, inclusive, an average of 20% of retail sales for that period.
b) 25% by December 31, 2016; and
c) 33% by December 31, 2020.

The statute defers to the CPUC to set "interim" targets for the years not specified above. What that means is that the CPUC may set a different percentage target for the years 2014, 2015, 2017, 2018, and 2019. The CPUC has not yet issued a final decision adopting "interim" targets for these years, although it is expected that targets will be adopted by the end of 2011. Furthermore, any interim (annual) procurement targets set by the CPUC should not be

enforceable. They are simply used to develop the total procurement quantity for each compliance period, which is enforceable.

Similar modifications are likely needed to the same discussion on procurement targets for POUs on page 17. For example, the discussion on page 17 states that "POUs may beginning January 1, 2011, count excess procurement in one compliance period toward RPS procurement targets in any subsequent compliance period." This statement implies there are no restrictions on banking excess procurement. The CPUC has yet to decide on rules for banking excess procurement and once the CPUC makes that determination those same rules will apply to the POUs pursuant to the statute which states that "Rules permitting the utility to apply excess procurement in one compliance period to subsequent compliance periods in the same manner as allowed for retail sellers pursuant to Section 399.13."

VI. PG&E SUPPORTS INTRODUCTION OF AGGREGATED FACILITIES APPLICATION (CEC-RPS-3 FORM) BUT NOT FOR TRACKING NET SURPLUS GENERATION UNDER THE AB 920 PROGRAM

On page 76, in section "2. Aggregated Facilities," a proposal to streamline the process for distributed generation facilities to become RPS-certified is introduced. This program provides an aggregated application process for wind and solar photovoltaic facilities that mirrors the aggregated process in WREGIS. PG&E supports this thoughtful streamlined approach, which is compatible with the current WREGIS aggregation method. This will provide value to many DG customers interested in creating RECs for their behind the meter generation.

PG&E believes, however, that this will not be an effective method for AB 920 Net Energy Metering (NEM) customers to track the expected small quantities of net surplus generation. Requiring AB 920 NEM customers to work through aggregators to track these small quantities is burdensome and infeasible. Additionally, with the amount of net surplus generation expected to be very small and given the complexity of administration, it will likely not be cost effective for an aggregator to participate in this program. Unlike other DG generators, NEM surplus generation amounts will only be trued up once per year. Therefore, not only will the aggregators have to line up similar generation technology for the aggregated group, but also projects with the same true-up month. For the small amount of RECs expected from this program, a much easier approach would be to allow RPS credit from these NEM surplus generators to occur without WREGIS tracking. PG&E appreciates the role WREGIS plays to ensure no double counting of renewable resources, but the amount of generation compensated under AB 920 is very small, transactionally random, and will be simply lost if customers are required to pay an aggregator in order to receive compensation. To prevent double counting from these net surplus generators, the CEC can require each facility during the RPS certification process to attest they will not report any net surplus generation to any renewable energy tracking system. The only generation these facilities will be permitted to report to a tracking system will

be the generation that is not compensated under AB 920 (*i.e.,* the facility's total generation less the facility's net surplus generation).

VII. DE MINIMIS FOSSIL FUEL USE LANGUAGE SHOULD BE CLARIFIED TO ALLOW UP TO THE DE MINIMIS LEVEL OF NONRENEWABLE FUEL USE TO COUNT AS RENEWABLE ENERGY.

On page 47, in section "7. b. De Minimis Fossil Fuel Use," the RPS Guidebook states that if the nonrenewable fuel or energy resource use exceeds the allowable de minimis quantity, then only the renewable portion of the generation will be considered RPS eligible. This exclusion of energy generated using the allowable de minimis level of nonrenewable fuel to count as renewable energy is inconsistent with the Public Utilities Code Section 399.12(h) (3). Section 399.12(h)(3) states that "electricity generated by an eligible renewable resource attributable to the use of nonrenewable fuels, beyond a de minimis quantity used to generate electricity in the same process through which the facility converts renewable fuel to electricity, shall not result in the creation of a renewable energy credit." Even where the generating facility uses nonrenewable fuels in excess of the de minimis amount, Section 399.12(h)(3) does not exclude the electricity attributable to the use of nonrenewable fuels up to the de minimis quantity from eligibility for renewable energy credits. PG&E recommends that this section of the RPS Guidebook be clarified in accordance with the statute to allow such generation from allowable de minimis quantities of nonrenewable fuels to count as renewable energy.

VIII. PUBLIC REVIEW OF PROPOSED GUIDEBOOK CHANGES IS AN INTEGRAL PART OF THE PROCESS

On page 37, in the section "6. Municipal Solid Waste", it is noted that eligibility requirements in gray regarding Municipal Solid Waste are "being reconsidered by the Energy Commission at this time. **The final draft RPS Guidebook may contain revisions to these requirements.**" (emphasis added). Likewise, Attachment B to the Revised Notice of Workshop raises additional questions that "may be addressed as proposed revisions."

It is not clear to PG&E whether any modifications to Section 6 or in response to Attachment B will be circulated for public review prior to inclusion in the "final draft". PG&E suggests that the document be modified to clearly indicate that public comment will be sought prior to any modifications being adopted by the CEC.

IX. CONCLUSION

PG&E supports adoption of the RPS Guidebook, with the modifications noted above.

Sincerely,

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