Pacific Gas and Electric Company

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California Energy Commission
Dockets Office, MS-4
Re: Docket No. 13-IEP-1M
1516 Ninth Street
Sacramento, CA 95814-5512

Re: Status of Bioenergy Development in California: Comments of Pacific Gas and Electric Company

I. INTRODUCTION

On June 3, the California Energy Commission (CEC) held a workshop to discuss the status of bioenergy development, recent or potential challenges affecting the development of bioenergy, and to assess the benefits of bioenergy development. Pacific Gas and Electric Company (PG&E) participated in that discussion and offered an update on the role of bioenergy in PG&E's electric energy portfolio, along with procurement opportunities for bioenergy, and challenges to increased bioenergy deployment.

PG&E is the largest purchaser of bioenergy in the state. Bioenergy projects play an important role in PG&E's Renewables Portfolio Standard (RPS) portfolio and are sourced from both biomass and biomethane generation. Biomass resources include forest biomass, agriculture residues, and urban waste, whereas biomethane resources include animal waste, municipal waste, and landfill gas. PG&E remains focused on achieving the RPS requirements in a manner that balances safety, reliability, and affordability for customers. PG&E provides specific comments below on other topics discussed at the workshop, including implementation of Senate Bill (SB) 1122, costs to customers, interconnection issues, and societal benefits.

II. SB 1122 IMPLEMENTATION MUST FOCUS ON COST TO CUSTOMERS

PG&E is actively engaged in the SB 1122 implementation proceedings at the California Public Utilities Commission (CPUC). These proceedings are intended to facilitate the development of bioenergy resources by creating a market-based procurement mechanism for these resources. The state legislature indicated a desire to foster the development of bioenergy resources in passing SB 1122, and PG&E is supportive of those efforts with the appropriate balance between resource development and customer cost. Accordingly, PG&E continues to advocate for a cost cap to the SB 1122 program, which would be consistent with the cost containment mechanism required under the broader RPS program in CPU Code Section 399.15(c) that the CPUC plans to address in 2013. Additionally, an equitable cost allocation mechanism is needed because of the

very unique circumstances in implementing this statewide program. A recently-released draft study by Black & Veatch[1] demonstrates that SB 1122 sub-category target allocations may result in disproportionate program costs among investor-owned utilities (IOUs) because comparably costly resources are located within an individual IOU's service territory. In addition, inherent resource constraints unique to each IOU's service territory may challenge bioenergy development. As a result, IOUs may not have the same opportunities to contribute to the success of this broad, statewide IOU program. Any statewide cost sharing mechanism should ensure that the costs of procuring energy from SB 1122 projects are fairly allocated among the three IOUs. PG&E's focus is on ensuring its customers receive the best value at the lowest cost for these resources.

A cost cap and equitable cost allocation are critically important in the implementation of SB 1122. While some characterize the SB 1122 program megawatt limit of 250 MW as small, the cost associated with this tranche of procurement is not. PG&E is very concerned about the magnitude of costs with this limited program and its impact on customers. The Black & Veatch draft report estimates annual net IOU customer expenditures of $245 million and $365 million, for projects less than 3 MW in size in SB 1122 program costs for the 250 MW program.[2],[3] Based on the annual expenditure estimate and a 20-year term power purchase agreement (PPA) translates nominally into approximately $4.9 billion to $7.3 billion in financial commitment which represents a significant cost to utility customers.

While there may be some societal benefits these projects provide, it is not clear that the cost of these benefits should be borne solely by IOU electric customers. At the June 3 CEC workshop, some argued that there is very little difference between a taxpayer and a utility customer. This is not the case. Only about 70% of the statewide electric customers are customers of the IOUs. Furthermore, there is no relationship between the manner in which utility procurement costs are allocated, and the way in which taxes are apportioned. Accordingly, PG&E respectfully disagrees that it is appropriate for societal costs to be internalized in the electric rates of a subset of the state's electric customers (i.e., only IOU customers, not all electric customers or taxpayers in the state).

Given the high potential costs identified in the Black & Veatch report, a careful balancing of the customer protections applicable to the RPS program and contained in Section 399.20 is needed. These customer protections include the ratepayer indifference requirement, along with a

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[1] Black and Veatch, Draft Consultant Report for the CPUC on Small-Scale Bioenergy: Resource Potential, Costs, and Feed-in-Tariff Implementation Assessment, April 9, 2013, page 1-3 and 1-4. http://www.cpuc.ca.gov/NR/rdonlyres/9ABE17A5-3633-4562-A6DA-A090EB3F6D07/0/SmallScaleBioenergy_DRAFT_04092013.pdf

[2] Assumes the megawatts are allocated by IOU share of peak load and that no incentives are provided to the projects statewide (other resource allocation scenarios in the Draft Report resulted in different cost estimates).

[3] Black and Veatch, Draft Consultant Report for the CPUC on Small-Scale Bioenergy: Resource Potential, Costs, and Feed-in-Tariff Implementation Assessment, April 9, 2013, page 1-9. http://www.cpuc.ca.gov/NR/rdonlyres/9ABE17A5-3633-4562-A6DA-A090EB3F6D07/0/SmallScaleBioenergy_DRAFT_04092013.pdf

requirement that the CPUC must set procurement expenditure limitations at a level that prevents "disproportionate rate impacts."[4] These provisions must be considered in the implementation of SB 1122 and provisions to mitigate the cost impact are an essential element of protecting customers.

III. INTERCONNECTION PROCESSES ARE IMPROVING

A number of stakeholders at the June 3 CEC Workshop and in the CPUC's SB 1122 proceedings have raised concerns over interconnection challenges for bioenergy projects. It is unclear whether interconnection availability for bioenergy projects is materially different than that for other renewable projects, such as wind and solar. Renewable energy developers may face grid capacity constraints in various counties, but it is not clear that bioenergy projects are systematically or disproportionally affected by these constraints.

Section 399.20 requires that projects under the renewable feed-in tariff (FIT) program be "strategically located" in a manner that optimizes the deliverability of electricity generated at the facility to load centers. The CPUC has defined "strategically located" in implementing the FIT program under SB 32. Project eligibility under the adopted FIT market-based procurement mechanism, referred to as the Renewable Market Adjusting Tariff (ReMAT), requires that projects interconnecting to the grid should not have transmission upgrade costs above $300,000.[5] The $300,000 threshold for "strategically located" under ReMAT applies only to transmission system network upgrades and not to other interconnection work, including interconnection facilities and distribution upgrades. Moreover, the ReMAT PPA approved by the CPUC on May 23, 2013 allows counterparties to remain eligible for the program if the seller's transmission network upgrade costs exceed $300,000 after the PPA has been executed, if the Seller agrees to fund any network upgrade costs exceeding the $300,000 limit. According to the CPUC's Decision 13-05-034, sellers whose interconnection studies show transmission network upgrades of more than $300,000 before a contract is signed are not eligible for the FIT program because it would undermine the notion of "strategically located."

Interconnection requests have significantly increased over the last several years, far outpacing processes developed for fewer but larger generating facilities. PG&E is engaged in a number of external and internal initiatives to address challenges that have developed from the acceleration of RPS-eligible interconnection requests to PG&E's transmission and distribution systems. As part of these initiatives, PG&E is or has worked with the California Independent System Operator (CAISO) and the CPUC to amend the Wholesale Distribution Tariff (WDT) to better handle higher volumes of interconnection requests. PG&E has also worked as part of the Rule 21 stakeholder process to develop a process and agreements to provide RPS-eligible generators an interconnection path for exporting generators that ultimately enter into a Public Utility Regulatory Policies Act PPA (also referred to as a QF PPA) with PG&E. Additionally, PG&E

[4] Section 399.15(d)(1)
[5] Decision 12-05-035 Revising Feed-in Tariff Program, Implementing Amendments to Public Utility Code Section 399.20 Enacted by Senate Bill 380, Senate Bill 32, and Senate Bill 2 1X, May 24, 2012.

has worked with the CAISO on its efforts via the Generation Interconnection and Deliverability Allocation Procedures (GIDAP) to streamline ratepayer-funded transmission additions and upgrades under a single comprehensive process and provide incentives for renewable energy developers to interconnect to the CAISO grid at the most cost-effective locations.

Lastly, the CEC has implemented a working group to examine the interconnection process for synchronous generators, which are used in bioenergy generation. Interconnection times for bioenergy generators are usually longer than the time needed to interconnect solar PV, primarily because grid-interactive solar PV inverters are pre-designed to be non-islanding, not to re-energize a dead circuit, to have low harmonics, and are pre-tested by a national laboratory. PV inverters are designed to behave similarly no matter the make and size. Synchronous generators, although PG&E is familiar with the characteristics of these units, can vary significantly in design and mode of operation. They may have more operating modes and use more complicated schemes. Synchronous generators are usually larger in size and also have much higher fault duties and more system impact. As a result, additional analysis must be performed when synchronous generators want to interconnect to ensure that system safety and reliability are not compromised.

IV. SOCIETAL BENEFITS SHOULD NOT BE BORNE SOLEY BY ELECTRIC CUSTOMERS

Bioenergy projects are asserted to provide a number of societal benefits, including wildfire risk reduction and jobs in rural communities. PG&E remains concerned that the value ascribed to the purported benefits has not been quantified. PG&E is very interested in and engaged with a number of groups working to quantify these values. However, as noted above, costs associated with acquiring purely societal attributes should not be borne by PG&E electric customers through energy procurement and generation rates.

It is also important to note that some of these societal and environmental value elements are already captured in the price paid for the bioenergy energy. For example, the market price for electricity, which may serve as a measure for evaluating the reasonableness of an RPS contract price, captures the value of greenhouse gas (GHG) emissions associated with bioenergy generation.

V. PG&E'S BIOENERGY PORTFOLIO

A number of questions were raised during the workshop about PG&E's bioenergy portfolio, specifically new contracts which were signed over the last five years. Below is a public list of the 21 biomass and biomethane contracts executed since 2008 representing a total of about 260 MWs.

Bioenergy Contracts Executed by PG&E Since 2008

Contract Name	Program Type	Expected Capacity (MW)	Contract Execution Year	Facility Type	Technology Type	Location	Contract Status
Santa Maria II	FiT	1.42	2008	New	Biomethane Generation	Santa Maria, CA	Executed
Wadham Energy LP	RPS	26.5	2008	Existing	Biomass	Williams, CA	Executed
Big Valley Power, LLC	RPS	7.5	2009	Existing	Biomass	Bieber, CA	Terminated
Castelanelli Bros. Biogas	FiT	0.3	2009	Existing	Biomethane Generation	Lodi, CA	Executed
DTE Stockton	RPS	45	2009	Repowered / Restarted	Biomass	Stockton, CA	Executed
Ortigalita Power Company (Madera Project)	FiT	0.75	2009	New	Biomass	Merced, CA	Executed
Woodland Biomass	RPS	25	2009	Existing	Biomass	Woodland, CA	Executed
Anderson Biomass Plant (Kiara Biomass)	RPS	6.8	2010	Repowered / Restarted	Biomass	Anderson, CA	Executed
Blake's Landing Farm	FiT	0.08	2010	Existing	Biomethane Generation	Marshall, CA	Executed
Mt. Poso	RPS	44	2010	Repowered / Restarted	Biomass	Bakersfield	Executed
Potrero Hills Landfill	RPS	8	2010	New	Biomethane Generation	Suisun, CA	Executed
Sunshine Landfill	RPS	20	2010	New	Biomethane Generation	Sylmar, CA	Executed
Central Valley Ag Power	FiT	1.5	2011	New	Biomass	Oakdale, CA	Executed
Toro SLO Landfill	FiT	1.5	2011	New	Biomethane Generation	San Luis Obispo, CA	Executed
Verliant Energy Gustine-Pires	FiT	1.5	2011	New	Biomethane Generation	Gustine, CA	Executed
Verliant Energy Gustine-Xavior	FiT	1.5	2011	New	Biomethane Generation	Gustine, CA	Executed
ABEC Bidart - Old River LLC	RPS	1.84	2012	New	Biomethane Generation	Bakersfield, CA	Executed
ABEC Bidart - Stockdale LLC	RPS	0.6	2012	New	Biomethane Generation	Bakersfield, CA	Executed
Forward Power Plant	QF	0.7	2012	Existing	Biomethane Generation	Stockton, CA	Executed
Liberty V Energy	RPS	4.5	2012	New	Biomass	Lost Hills, CA	Terminated
SPI Biomass Portfolio*	RPS	58	2012	1 New, 4 existing	Biomass	-	Executed

*includes 5 facilities

VI. CONCLUSION

PG&E welcomes the opportunity to meet with CEC staff on these important topics.

Sincerely,

/s/

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