PACIFIC GAS AND ELECTRIC COMPANY
Renewable Portfolio Standard
Rulemaking 11-05-005
Data Response

PG&E Data Request No.:	EnergyDivision_001-01 through 07 (1A, 1G, 1H, 1i, 1J, 3A, 3B, 3C, 4, 5A, 5B, 5C, 6, 7A, and 7B)		
Request Date:	November 16, 2012	Requester DR No.:	001
Date Sent:	December 10, 2012	Requesting Party:	Energy Division
PG&E Witness:	Various	Requester:	Michele Kito; Sean Simon

CONFIDENTIAL INFORMATION SUBMITTED IN ATTACHMENT TO QUESTION 1 A UNDER DECISION 06-06-066 AND GENERAL ORDER 66-C

QUESTION 1

Section 910(a)(1) of the Public Utilities Code states that the Commission shall prepare a report, including "All electrical corporation revenue requirement increases associated with meeting the renewables portfolio standard, as defined in Section 399.12, including the direct procurement costs for eligible energy renewable resources and renewable energy credits, administrative expenses for procurement, expenses incurred to ensure a reliable supply of electricity, and expenses for upgrades to the electrical transmission and distribution grid necessary to the delivery of electricity from eligible renewable energy resources to load."

QUESTION 1A

Please provide actual RPS expenditures for each facility for 2011 as well as any expenditures for renewable energy credits in 2011. It is our understanding that the utilities provided much of this data in response to data requests for the "Padilla" report. Please update this information, including all fields provided in the most recent Padilla data response to the Energy Division, and please explain if and why the sum of the total RPS costs differs from the totals provided in the utilities' 2012 RPS Procurement Plan, Cost Quantification Tables. Please provide this information in excel format.

ANSWER 1A

Please see the confidential attachment entitled "03.RESPONSE_PU Code 910_DR_ED_001-Q01a-Atch01-CONF". There are no differences between the Renewables Portfolio Standard (RPS) cost totals provided in PG&E's 2012 RPS Procurement Plan and the attachment.

QUESTION 1G

Please identify all transmission projects constructed or planned for the RPS program at any point during the implementation of the RPS program.

ANSWER 1G

PG&E is in the exploration stages of the possible construction of the "Central California Transmission-Greater Fresno Area 230kV Upgrade Project" which may be operational in 2020 and of which a part may be considered to support of the RPS program.

For transmission level network upgrades due to generator interconnection projects, please see response 1.i.

QUESTION 1H

Please identify the costs associated with the transmission projects identified in g. above.

ANSWER 1H

The RPS-attributable portion of the "Central California Transmission-Greater Fresno Area 230kV Upgrade Project" discussed above is currently estimated to be between $100 million to $125 million. For transmission level network upgrades due to generator interconnection projects, please see response 1.i.

QUESTION 1I

Please identify the RPS transmission related costs that were collected in rates in 2011 and please explain how this figure was calculated and/or estimated. Please provide your workpapers in excel format, with links intact.

ANSWER 1I

Below is a yearly accounting of ongoing refund payments - deposits and interest - that PG&E has made since 2003 and expects to make through 2015 for network upgrades due to generator interconnection projects at the transmission level. These generators employ RPS technologies including wind, solar, small hydro, geothermal, biomass, and waste.

Year	Interest	Deposit
2004	($96,090)	($632,837)
2005	($65,408)	($502,711)
2006	($64,209)	($546,311)
2007	($1,833,429)	($3,942,650)
2008	($545,110)	($2,533,662)
2009	($280,377)	($2,372,148)
2010	($199,718)	($2,731,435)

2011	($35,562)	($646,490)
2012	($16,268)	($447,593)
2013	($6,324)	($235,846)
2014	($1,728)	($47,376)
2015	($288)	($23,688)
Total	($3,144,509)	($14,662,749)

Work papers for this table are included in the file entitled “04.RESPONSE_PU Code 910_DR_ED_001-Q01i-Atch01”.

It is not possible to determine “…RPS transmission related costs that were collected in rates in 2011” for several reasons. PG&E’s Transmission Owner 13 (TO13) rate case, effective March 1, 2011, was a black box settlement that did not specify a portion of the settled rates attributable to RPS. Further, rate requests include a forecast of future refunds and of ongoing trued-up past refunds. The expenditures summarized in the table above represent actual payments made by PG&E. With regards to ratemaking, the interest portion of the refunds are considered an expense, whereas the refund of the customer deposit – the payment for the network upgrade costs– would add to the rate base similar to a capital expenditure.

QUESTION 1J

Please identify the expenses for upgrades to distribution grid necessary to the delivery of electricity from eligible renewable energy resources to load. Please separate these costs into those that are paid for by generators and those that will be recovered from ratepayers. For those distribution costs to be paid by ratepayers, please provide the 2011 revenue requirement associated with these distribution expenditures. Please provide your workpapers in excel format, with links intact.

ANSWER 1J

For non-net energy metering (NEM) interconnections to PG&E's distribution system under either California Public Utilities Commission (CPUC) or Federal Energy Regulatory Commission (FERC) jurisdiction, the Interconnection Customer pays for distribution system modifications triggered by the Interconnection Customer's generation project. As a result, PG&E does not include in rates the expenses associated with any such modifications.

The cost of the UOG caused upgrades to the distribution grid necessary to the delivery of electricity from UOG RPS-eligible renewable energy resources are included in the UOG expenditures provided in response to Question 1A.

QUESTION 3

Section 910(a) (3) requests the following information: "All costs incurred by electrical corporations for incentives for distributed and renewable generation, including the self-generation incentive program, the California Solar Initiative, and net energy metering."

QUESTION 3A

For the SGIP program, please separately provide the revenues that were authorized, collected, and spent in 2011.

ANSWER 3A

Decision 09-12-047 authorized PG&E to collect $36 million for the Self Generation Incentive Program (SGIP) in 2011.

PG&E collected $29.52 million from its electric customers through the Distribution Revenue Adjustment Mechanism (DRAM) and $6.49 million from its gas customers through the Core Fixed Cost Account (CFCA) and the Non-Core Customer Class Charge Account (NCA).

PG&E spent $58.90 million on SGIP in 2011. For more detailed expenditures, the Energy Division has access to the Statewide SGIP database.

QUESTION 3B

For the CSI program, please separately provide the revenues that were authorized, collected, and spent in 2011.

ANSWER 3B

D.10-04-017 authorized PG&E to collect $105 million for the California Solar Initiative (CSI) in 2011.

PG&E collected $105 million from its electric customers through the DRAM.

PG&E spent $128.47 million on CSI in 2011, which includes the General Market CSI and the following CSI-subprograms: Single Family Affordable Solar Homes, Multi-family Affordable Solar Homes, Research, Development, Demonstration &Deployment and Electric Thermal Programs. For more detailed expenditures, PG&E has attached the most recent CSI Semi-Annual expense report, from July 2012.[1]

QUESTION 3C

1 See attachment "05.RESPONSE_PU Code 910_DR_ED_001-Q03B-Atch01.xls".

Please identify and provide the costs associated with any other incentives for distributed and renewable generation, other than those identified in a. and b. above or identified in Question 1.

ANSWER 3C

The NEM program provides an incentive for customers who install renewable generation up to 1 MW that is sized to offset the customer's own load. To calculate the 2011 cost impacts from NEM of $132.2 million, PG&E relied on the most recent CPUC study of the CSI program, published in April 2011. The cost of the CSI incentive itself was removed from the program impacts, leaving the costs of NEM. There are several reasons why these results should be considered stale:

- Gas price forecasts are significantly lower today
- The highest residential tier rates are lower today
- The 2011 study ignored the impact of SB 695, which loads most residential cost increases onto the higher tiers.

The CPUC has undertaken an updated study of the cost shifts from NEM as part of the distributed generation Rulemaking (R.12-11-005), but the updated study will not be available until Q2 2013. PG&E suggests the CPUC alert the Legislature that the numbers provided herein are based on the stale April 2011 study and an update is imminent.

<u>Methodology</u>

Our calculation of the cost shifts from the NEM program started with levelized per-kWh cost shift using ratepayer impact (RIM) test for benefit cost (BC) analysis.

> The value used was taken from Table 56, page A-38 of E3 analysis of the CSI program. We used the value for PG&E for 2009.
>
> We decreased the cost shift by the amount attributable to CSI program incentives because they will be included in the CSI program in this data request.
>
> The value used was taken from Table 31, page 90. (Without PG&E-specific information available, we assumed that the PG&E number would be the same as the statewide number).
>
> We then increased the cost shift by removing the T&D benefits, which PG&E has consistently explained were inappropriately included.
>
> The value used was taken from Table 32, page 91. (Assume 2009 has same 2 cents as 2008)

We estimated the generation from customers interconnected under the NEM program.

The value used was from a monthly internal report on NEM generation as of December 2011.

Finally we assumed a capacity factor of 20% to calculate the energy generated by NEM customers in 2011.

The cost shift is the total generation (in kWh) times the estimated per kWh cost shift of $0.14.

Calculation of Cost of NEM Program

$0.22	RIM cost shift for PG&E in 2009 (per kWh)
$0.12	RIM cost shift without CSI rebate (per kWh)
$0.14	RIM cost shift without T&D benefits (per kWh)
558.8	Installed NEM as of December 31, 2011 (MW)
20%	Assumed Capacity Factor
979,017,600	Total Generation (kWh)
$132,167,376.00	Total cost shift in 2011

QUESTION 4A

Section 910(a) (4) requests the following information: "All cost savings experienced, or costs avoided, by electrical corporations as a result of incentives for distributed and renewable generation."

Please explain whether you believe the report mandated by PU Code 2827 will address the costs savings requested above. If not, please provide your estimate of the cost savings experienced or avoided in 2011 as a result of distributed generation programs.

ANSWER 4A

No. The report mandated by PU Code 2827 will not address all of the incentives provided to distributed and renewable generation. The report will only address the impacts of the NEM program, specifically cost savings and costs avoided for distributed generation interconnected through the NEM program. However, PG&E reserves endorsement of the results of the PU Code 2827 report until PG&E has an opportunity to review those results.

Non-renewable distributed generation that is eligible for the SGIP is not eligible to participate in NEM. Therefore, the report mandated by PU Code 2827 will exclude those cost savings attributable to non-renewable distributed generation. PG&E estimates that $9.4 million to $12.7 million is a reasonable estimation of the avoided costs of non-renewable distributed generation.

The E3 study entitled "CPUC Self-Generation Incentive Program Tenth-Year Impact Evaluation Final Report"2 will not provide an estimate of the avoided costs for non-renewable generation installed as a result of the SGIP program. PG&E provides a range of the avoided costs from these installations as described below.

PG&E notes that its estimated range of SGIP-related avoided costs cannot simply be subtracted from the costs for SGIP provided in response to Question 3A to arrive at net benefits because the revenue collected to support SGIP incentives are only a small part of the total rate impacts of the SGIP program. Specifically, there are significant revenues that would otherwise be contributed by the recipients of SGIP projects that need to be considered as part of a thorough benefit/cost analysis. Furthermore, there are likely grid costs imposed by SGIP customers that must be considered as part of any complete analysis.

Avoided Costs from Nonrenewable SGIP Installations

$9,408,402	Low
$12,729,015	High

A description of the derivation of these avoided costs is below.

Data Sources

- Installed MWs are from nonrenewable SGIP program installations as of December 2011.
- Avoided Energy is the average default load aggregation point (DLAP) for PG&E for 2011.
- Avoided Capacity is from the CAISO's Capacity Procurement Mechanism (CPM) price in 2011.
- Capacity factors are derived from "CPUC Self-Generation Incentive Program Tenth-Year Impact Evaluation".
    - Capacity factors in Tables 4-5 and 4-10 were weighted by technology using rebated capacity from Table 4-4.
- Because the derivation is from a mix of statewide, PG&E-specific and installation data that is not statistically significant, and because the data was for 2010, not 2011, the estimate was bounded.
    - Low and High capacity factor and peak capacity are the point estimate plus and minus 15%.
- Line losses are assumed to be 9% and are applied to both energy and capacity avoided costs.
- Reserve margin is assumed to be 15% and is applied to capacity avoided costs.

Methodology

2 http://www.cpuc.ca.gov/NR/rdonlyres/CF952F3B-0C3C-481D-968A-420F92FC2901/0/SGIP_2010_Impact_Eval_Report.pdf

- Installed MW is multiplied by the low capacity factor to get the low estimate of annual energy generated.
- Installed MW is multiplied by the low peak capacity to get a low estimate of peak savings.
- Low Avoided Cost is the low estimate of energy times avoided energy plus low capacity times avoided capacity.
- High energy, high peak capacity and high avoided costs are calculated similarly.
- Both Low and High avoided costs are adjusted for line losses and reserve margin.

<u>Calculation of Avoided Costs of Nonrenewable SGIP Installations for 2011</u>

77.1	MW Installed by EOY 2011	
$31.20	Avoided Energy (per MWh)	
$67.50	Avoided Capacity (per kW-yr)	
9%	Avoided Line Loss %	
15%	Avoided RA % (applied to capacity)	
	2011 Total Generation (MWh)	
205,679	0.3045312	Low Capacity Factor
278,272	0.4120128	High Capacity Factor
	2011 Peak Capacity	
28.84	0.3740221	Low Peak Capacity
39.01	0.5060299	High Peak Capacity

QUESTION 5

Section 910(a)(5) requests the following information: "All renewable, fossil fuel, and nuclear procurement costs, research, study, or pilot program costs, or other program costs for which an electrical corporation is seeking recovery in rates, that is pending determination or approval by the commission."

QUESTION 5A

Please provide actual expenditures for each fossil and nuclear facility for 2011. Please provide expenditures for capacity and energy separately for each facility. Please provide actual generation in 2011 for each facility. Please provide this data in excel format.

ANSWER 5A

Please see the attached file entitled "06.RESPONSE_PU Code 910_DR_ED_001-Q05-Atch01".

QUESTION 5B

Please provide actual expenditures for research, study, or pilot program costs in 2011 and please separately identify each program and the associated costs.

ANSWER 5B

PG&E did not have any other project or program costs that were pending in 2011.

QUESTION 5C

Please provide a list of other project or program costs that were pending in 2011 and the amount of each individual request.

ANSWER 5C

PG&E did not have any other project or program costs that were pending in 2011.

QUESTION 6A

Section 910(a) (6) requests the following information: "The decision number for each decision of the commission of recovery in rates of costs incurred by an electrical corporation since the preceding report."

> Please provide the decision numbers and resolution numbers for costs that were collected in rates in 2011.

ANSWER 6A

Below are the decisions and resolutions issued in 2011 under Rulemaking (R) 08-08-009 and R.11-05-005 that authorized PG&E cost recovery:

D.11-03-036, D.11-12-020, D.11-12-052, D.11-12-052, Res.E-4389, Res.E-4390, Res.E-4393, Res.E-4402, Res.E-4415, Res.E-4415, Res.E-4418, Res.E-4423, Res.E-4427, Res.E-4430, Res.E-4433, Res.E-4436, Res.E-4443, Res.E-4444, Res.E-4447.

QUESTION 7

Section 910(a) (7) requests the following information: "Any change in the electrical load serviced by an electric corporation since the preceding report."

QUESTION 7A

Please provide the forecasted load for 2011 for bundled service customers, CCA/DA customers, and the total system.

ANSWER 7A

Please see the two tables in the file entitled 07.RESPONSE_PU Code 910_DR_ED_001-Q07-Atch01.xls. The sales forecast shown in 7a is drawn from PG&E 2011 ERRA Proceeding, A. 10-05-022, Table 2-2. The recorded data presented in 7b is calendarized data and is shown for comparability to the forecast.

QUESTION 7B

Please provide the actual load for 2011 for bundled service customers, CCA/DA customers, and the total system.

ANSWER 7B

Please see the two tables in the file entitled 07.RESPONSE_PU Code 910_DR_ED_001-Q07-Atch01.xls. The sales forecast shown in 7a is drawn from PG&E 2011 ERRA Proceeding, A. 10-05-022, Table 2-2. The recorded data presented in 7b is calendarized data and is shown for comparability to the forecast.