Pacific Gas and Electric Company

March 5, 2008

Charles McGlashan, Supervisor, District 3
Board President
County of Marin
3501 Civic Center Drive, Suite 329
San Rafael, CA 94903

Dear Supervisor McGlashan:

We appreciate the opportunity to review and evaluate the Marin Community Choice Aggregation (CCA) Business Plan Draft Report dated January 2008 (referred to hereafter as the "BP"). As we have shared with you previously, while PG&E supported the concept behind AB117 which created the opportunity for local public agencies to acquire power for their residents, businesses and municipal facilities, we believe we have an obligation to our customers to evaluate local proposals for CCA programs to determine whether or not the proposals can deliver the promised benefits.

In October 2007, PG&E provided comments in response to your request for feedback on the September 2007 preliminary draft of the BP. In that response, PG&E commented on the lack of detail in the draft and stated its belief that the draft's key conclusion – that a Marin CCA could achieve a significantly higher percentage of renewable power than is available from PG&E electric service at rates that are at, or below, PG&E's generation rate – is unsupportable.

While the January 2008 BP adds some detail that was previously missing and makes some modifications to its assumptions about the costs of resources, it falls well short of a thorough documentation of its financial assumptions and results. But more fundamentally, PG&E believes the BP's key conclusion, that a Marin CCA could achieve a significantly higher percentage of renewable power than is available from PG&E electric service at rates that are at, or below, PG&E's generation rate, remains unsupportable, since:

- The BP consistently overestimates the availability of renewable energy at a cost competitive with conventional supplies.

- The forecasts contained in the BP regarding PG&E's generation rates are erroneous and misleading, even going so far as to state that "the forecast underlying this business plan projects an average increase of 3% per year in PG&E's generation rates . . ." but then using a rate of 3.5% in the pro forma. In addition, the BP confuses PG&E's bundled rate (a rate including generation, transmission, distribution, public goods, etc.) with a generation rate, resulting in misleading conclusions.

- On a variety of issues, the BP contains information and assumptions that are factually incorrect, unsupported by any evidence or simply belie the realities of the market. These issues include but are not limited to the benefits of tax-exempt financing, the CCA participation rate of Marin energy consumers, the availability of energy efficiency opportunities to the CCA, GHG reductions (since the BP assumes a much higher emission rate for PG&E than is accurate), and risk to all energy customers in Marin whether or not they participate in the CCA.

Based on detailed analyses prepared by PG&E and its consultants, customers not opting out of the Marin CCA will end up paying rates that begin at a level approximately 25% higher than those of PG&E's generation rates over the 2011 – 2025 time-frame. The premium will be even higher for customers being defaulted onto the County's proposed 100% Green Tariff (which the BP states would be automatic). While PG&E supports the notion that many Marin customers, in general, are willing to pay more for renewable supplies beyond the 20% than PG&E will be delivering or have under contract by 2010, the 2.7 to 4 cents/kWh premiums estimated in PG&E's analysis go well beyond any reasonable empirically-derived estimates of customer willingness to pay except perhaps for a small percentage of customers.

PG&E shares Marin's desires for increased renewables and reduced GHG emissions—but the CCA Business Plan does not lend any confidence that CCA is the way for Marin customers to achieve these shared objectives.

Even though the BP states there are a number of "off-ramps" further down the road, suggesting that the lack of data in the BP will be cured at a later stage, PG&E believes that there is little value in dedicating additional resources to an effort which has been in motion for several years but is still lacking a solid analytic foundation. We recommend that the elected officials in Marin continue to work with PG&E and other stakeholders in pursuing deeper and broader penetration of energy efficiency and renewable programs that can make a big difference in achieving real GHG emission reductions, without thrusting the County into the volatile power markets or encumbering half a billion dollars in debt for risky renewable energy investments.

Sincerely,

Redacted
Government Relations Consultant

cc: Susan L. Adams, Marin County Supervisor, District 1
Harold C. Brown Jr., Marin County Supervisor District 2, Board Vice President
Steve Kinsey, Marin County Supervisor District 4
Judy Arnold, Marin County Supervisor District 5, Board 2nd Vice President
County Administrator Matthew Hymel

PG&E's Comments on January 2008 Marin CCA Business Plan

1. Introduction

PG&E appreciates the opportunity to comment on the January 2008 Marin Community Choice Aggregation (CCA) Business Plan (hereafter, referred to as the "BP").[1] In October 2007, PG&E provided comments in response to Supervisor McGlashan's request for feedback on the September 2007 preliminary draft of the BP. In that response, PG&E commented on the lack of detail in the draft and stated its belief that the draft's key conclusion – that a Marin CCA could achieve a significantly higher percentage of renewable power than is available from PG&E electric service at rates that are at, or below, PG&E's generation rate – is unsupportable.

The January 2008 BP adds some detail that was previously missing (e.g., a financial pro forma is now included in Attachment A), and makes some modifications to its assumptions about the costs of resources (e.g., increasing the assumed installed cost of a wind generator from $1,488 per kW to $2,000 per kW). Furthermore, while the September 2007 draft BP described a single CCA power product that would begin at 25% renewable content, growing to 51% and ultimately 100%, the BP now segments its renewable offerings between a "Light Green" option that would grow from 25% to 51% renewable content, and a "100% Green" offering that would begin (and remain) at 100%. According to the BP, the former would be available at or below PG&E's generation rates, while the latter would cost approximately 20% more than PG&E's generation rates.

However, the BP falls far short of the goal of documenting its financial assumptions and results. Given the paucity of supporting data, PG&E was unable to replicate many of the estimates in the pro forma, and notes that there are a number of inconsistencies between the pro forma estimates and figures contained elsewhere in the BP.

Notwithstanding these technical shortcomings, the fundamental flaw of the September 2007 draft remains in the January 2008 version: the assertion that that the Marin CCA can offer significantly higher renewable content in its power supply (with its Light Green rate option) at rates equivalent to PG&E's is unpersuasive, both because the costs of power are underestimated and future PG&E generation rates are likely overestimated. This is directly attributable to the BP's reliance on a hypothesis -- instead of analysis -- that <u>if</u> power purchase agreements can be negotiated at a price of 8.8 cents per kWh for the first four years, then positive cash flows will result: "*The financial plan and customer rate impacts presented in Chapter 4 should be considered illustrative pending incorporation of prices that will be provided by the market in a Request for Bid that will be issued around January 2009 ...*"[2].

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[1] PG&E's comments focus primarily on the estimated costs of power to be supplied by a Marin CCA, relative to PG&E's forecasted generation rates. PG&E also addresses certain issues associated with various demand-side management programs, such as energy efficiency and solar. There are a number of other issues covered by the Marin CCA Business Plan that PG&E does not address in these comments. However, the fact that PG&E does not address these issues does not reflect PG&E's agreement with the manner in which they are addressed in the BP.

[2] See p.2 of BP. See also p.10: *"It is estimated the Authority would need to provide full requirements power supply for the four-year Implementation Period at an average cost of 8.8 cents per kWh (for power supply corresponding with the conventional/renewable mix provided in the Light Green Tariff) to be able to offer rates equal to those of PG&E. A pro forma for the implementation period, including generation rates equivalent to PG&E, is shown in the following table, based on a full*

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The BP takes a pass on assessing the likelihood that a supplier can be found offering a full requirements supply, with Marin's desired renewable content, meeting Marin's specific load shape, at this price.[3] The BP further fails to assess how the cash flow results would change should the price offered be different, except for one sentence noting that "… a 5% increase in market prices would increase the Authority's annual cost by nearly $6 million, enough to turn a projected surplus for 2011 into a deficit" (p.75). Such risk assessments do not require waiting, as the BP proposes, until "a future revision or supplement to this business plan" is conducted (p.75), but could and should be performed now.

Tables 1 and 2 present the results of an analysis performed by PG&E and its consultants comparing PG&E's estimates of Marin CCA costs to forecasted PG&E generation rates. Table 1 focuses on the period from 2014 through 2025 covered by the BP's Appendix A financial pro forma. That pro forma shows as its last row, blended CCA rates for each year during the period (i.e., rates which are averages of the 100% Green and the Light Green rates). The first row of Table 1 repeats those rates from the BP's Appendix A pro forma. The second row shows PG&E's estimates of the blended rate that the Marin CCA would have to charge in order to cover its costs when realistic assumptions are used to model those costs. The third row shows a forecast of PG&E's generation rates, developed by using the current 2008 average generation rate of $83 per MWh for Marin (i.e., the average rate calculated from just the bills of PG&E customers in Marin), and escalating it consistent with forecast information PG&E filed in 2007 with the California Energy Commission (CEC) as part of its Integrated Energy Policy Report (IEPR) proceeding.[4] As the table shows in the fourth and fifth rows, PG&E's forecasted generation rate is significantly below PG&E's estimate of the Marin CCA blended rate in every year during the 2014 - 2025 period.

Table 1. Marin CCA's Estimated Melded Rates vs. PG&E's Generation Rate

Generation Rates	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
BP Pro Forma –Marin CCA Blended Rate ($/MWh)	$104	$100	$104	$105	$105	$107	$111	$114	$115	$117	$118	$119
Estimated Marin CCA Blended Rate ($/MWh)	$131	$130	$131	$131	$131	$131	$132	$132	$132	$133	$133	$134
PG&E's Forecasted Rate ($/MWh)	$91	$92	$94	$95	$96	$98	$99	$101	$102	$104	$105	$107
Price Premium for Marin CCA ($/MWh)	$40	$38	$37	$36	$34	$33	$32	$31	$30	$29	$28	$27
Price Premium for Marin CCA (%)	44%	42%	40%	38%	36%	34%	33%	31%	29%	28%	27%	25%

requirements contract price of 8.8 cents per kWh. Costs and revenues presented in ***the table below are illustrative and subject to change based on responses to the County's and Cities' request for information and proposals from third party electric suppliers****."* (emphasis in original)

[3] The extent of the BP "analysis" is to reference, on p.2, information about "energy prices received by other CCA programs, such as the aspiring East Bay CCA Program and the San Joaquin Valley Power Authority (SJVPA), from the market." However, all of these prices are just "indicative," not final and binding on the supplier. As such, they have little relevance, except to perhaps establish a lower bound on what the eventual prices would be after a final agreement is negotiated with the supplier.

[4] PG&E submitted four forecast scenarios for the 2008-2016 period as part of the CEC's 2007 IEPR proceeding. The escalation rates of these four forecasts between 2008 and 2016 ranged from 0.44% per year to 2.45% per year. For this analysis PG&E used an escalation rate 1.5% per year, which is approximately the mid point of that range. The 1.5% per year escalation rate is also consistent with historical trends in PG&E's generation rate (see discussion in Section 3 below).

Table 2 focuses on the 2011-2013 period, the only period for which the BP shows a breakdown of the melded rate into its 100% Green and Light Green components.[5] The first row repeats the BP's estimates of the Light Green rate from the table on p.64. The second row presents PG&E's estimate of the Marin Light Green rate. This rate was derived from PG&E's estimates of the blended rates that the Marin CCA would have to charge in order to cover its costs, along with the assumptions (a) that the blended rate is a sales weighted average of the 100% Green and Light Green rates and (b) that the 100% Green rate is set at 1.2 times the Light Green rate.[6] The results in Table 2 show that, based upon more realistic cost assumptions, the Light Green rate significantly exceeds PG&E's rate for each year during the 2011-2013 period. And, of course, customers choosing the 100% Green option would have much higher rate differentials compared to PG&E's generation rate.

Table 2. Marin CCA's Estimated Light Green Rate vs. PG&E's Generation Rate

Generation Rates	2011	2012	2013
BP (p.64) – Marin CCA Light Green Rate ($/MWh)	$92	$96	$99
Estimated Marin CCA Light Green Rate ($/MWh)	$111	$111	$108
PG&E Forecasted Rate ($/MWh)	$87	$88	$89
Price Premium for Marin CCA ($/MWh)	$25	$23	$18
Price Premium for Marin CCA (%)	28%	26%	20%

2. Analysis of Marin CCA's Energy Costs

To arrive at the conclusions summarized above, PG&E contracted with several consultants to develop an estimate of the costs of a Marin CCA to meet the objectives stated in the BP with respect to the proposed renewable content of the power supply. Global Energy, Inc. developed a detailed bottoms-up analysis using a production simulation model to provide a real-time estimate of the relevant costs for conventional and renewable supplies. PA Consulting, Inc. provided critical inputs associated with renewable supply costs and availability.

The results show that it will cost significantly more than 8.8 cents per kWh, as theorized by the BP, for power costs for the 2011-2013 period for a supply mix satisfying the characteristics of the proposed Light Green Tariff. Furthermore, other cost elements assumed by the BP for JPA-owned renewable resources, including a 150 MW wind project and 50 MW biomass project, underestimate the actual costs and/or overestimate the performance characteristics of these resources. Appendix 1 shows a comparison of the resulting power costs presented in the BP, and those developed by the PG&E team, for the 2011–2025 time-frame.

Furthermore, the BP assumes that PG&E's generation rates will increase by 3.5% per year,[7] based on its statements that this mirrors the historic increases in PG&E's generation rates. However, as

[5] These rate breakdowns are shown in two tables in the BP, on p.63 (for the 100% Green option) and p.64 (for the Light Green option). These tables cover the 2010-2014 period. PG&E's Table 2 omits 2010 because PG&E's analysis of Marin CCA costs begins in 2011, the proposed first full year of CCA operations after all customer classes have been phased in.

[6] This 20% premium for the 100% Green rate over the Light Green rate seems to be the assumption made by the BP. See, for example Table 2 on p.9 where the comparison of the relationship between the 100% Green and Light Green rates demonstrates this relationship for each customer class.

[7] Page 77 of the BP asserts that PG&E's annual generation rate increase will be 3%. However, this is contradicted by p. 9 of the BP (see Table 2), as well as the Assumptions Sheet, both of which calculate PG&E's annual generation rate increase at 3.5%.

described in Section 3 below, this overstates the actual historic increases in PG&E's generation rates, and overstates the likely increases going forward.

The following sections provide additional details regarding PG&E's analysis, assumptions and results.

a. General Approach:

PG&E's analysis of the Marin CCA's power costs was performed utilizing a resource planning approach where least-cost generation resources are added to meet load, plus reliability requirements and Marin's stated targets for renewable supplies (including its identification of CCA-owned 150 MW of wind and 50 MW of biomass supplies starting in 2014). The cost of power is then calculated based on this resource build-out, while also taking into account other costs Marin may incur operating as a CCA.

Marin has indicated that it plans to get its targeted power needs from 2010–2013 by signing a "full requirements" power purchase agreement (PPA). However, in order for a supplier of such "full requirements" power to meet these specifications, it would need to incur the cost of acquiring that power supply by arranging for physical resources, and the supplier would be expected to price the PPA accordingly. The resource planning approach is the accepted methodology employed by utilities (investor-owned and municipal alike) in order evaluate the economics of serving load, whether through power supplied by a third party via a PPA, or through owned resources. The study period of this analysis is 2011–2025.

Whenever possible, the Marin BP was used as a guideline for resource and load detail, in order to establish as much common ground between the two analyses as possible, and therefore limit the areas where disagreement exists. Cost estimates for gas-fired and wind[8] resources were generally estimated using the California Energy Commission's (CEC) Cost of Generation (COG) Model (Version Beta 9 – January 2008). Costs for biomass and renewable power provided through a PPA were assumed at the cost set forth by the California Public Utilities Commission's (CPUC) market price referent (MPR) (issued in October 2007), since the MPR sets the floor price that owners of renewable supplies should be able to obtain for their power. However, there is much evidence to suggest that these prices are low, and actual prices will be higher.

b. Modeling Methodology:

Once the resource build-out was developed, Global Energy then performed an operation simulation, running a model employing a chronological hourly dispatch analysis that economically dispatches available resources to meet loads, taking into account the ability to make spot purchases and sales when economical.

Global Energy used its state of the art portfolio analysis model, Planning and Risk, to determine the power cost that Marin County would incur in meeting load. The model is an hourly chronological economic dispatch model, which dispatches resources to meet hourly loads. The model also reflects the reality that Marin would be able to buy and sell power in the wholesale spot market to perform optimal power dispatch in meeting these hourly loads. For example, if

[8] Although the CEC COG model was used in estimating the levelized capital costs of wind resources, the default installed cost assumption was changed to reflect recent findings in California wind development. This is discussed in detail in Section 2.c.v.

Marin could buy spot market power for less than the operating cost of an otherwise-needed Marin resource, it would likely do so. Similarly, if Marin had an excess resource available in a given hour, and the operating cost of that resource was lower than the wholesale spot market price, then Marin would likely run the resource and make the sale. Global Energy forecasts these wholesale spot market purchase and sale decisions based upon its hourly chronological dispatch models and data that replicate Western Electric Coordinating Council (WECC) wide spot markets for power. Global Energy sets the wholesale spot purchase and sale price at the Northern California hourly price forecast, which was created using its zonal market price forecasting model, MARKETSYM.

c. **Assumptions:**

i. *Load*

The 2011–2019 forecast of Marin's expected load was obtained from the Marin BP. While energy loads were reported for every year in the Marin BP, peak loads were only reported for the years 2011–2019. To estimate peak load for years 2020–2025, the average load factor over the years 2011–2019 was maintained from 2020–2025. Table 3 below summarizes the peak and energy load forecast that the PG&E team used in this analysis. These figures reflect total load including losses.

Table 3. 2011-2025 Marin Load Forecast

Load Forecast	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Peak (MW)	237	236	235	234	234	234	235	235	236	240	241	242	243	244	246
Energy (MWh)	1,256	1,252	1,253	1,257	1,261	1,266	1,272	1,277	1,284	1,288	1,295	1,302	1,308	1,314	1,321

ii. *Resource Build-outs*

The PG&E team used the Marin BP as a framework for resource build-out whenever possible. In the instances where information in the report was limited or ambiguous, PG&E used its professional judgment to develop reasonable assumptions. The resource build-out assumes that load will be met, that Resource Adequacy (RA) is satisfied by way of a 15% planning reserve margin, and that the BP's stated renewable goals are satisfied. The BP assumes a blended 70% renewable goal starting in 2011 and 81 percent in 2014. PG&E structured its analysis assuming a one-year jump in renewable resource build-out between 2013 and 2014. Based on the fact that Marin load peaks in the winter and that Northern California wind counts very little toward RA needs in these winter months (per CPUC rules), PG&E assumed the wind would not count toward RA needs.

For the 2010–2013 time period, when Marin intends to get its supply from a full requirements contract (i.e., a contract that promises to meet all load demands as they arise from moment to moment and meets RA requirements of the CPUC and CAISO, meeting renewable targets, and providing the operating reserves required by FERC/NERC/WECC), the provider of the power will need to identify the resources it will use. Until these resources are identified and "controlled" by the seller, the seller cannot claim their usage and the seller will not be able to estimate what it will cost to provide the power. Surely, no seller will sell power at a price lower than its cost.

For the period from 2014 and beyond, when Marin intends to finance, build, and own renewable resources, a whole new uncertainty arises. That uncertainty relates to development risks of proposed power projects. Renewable projects in particular are projects that owners can invest considerable money in pursuing, only to later discover that the project cannot be permitted or that unanticipated high project costs make it uneconomic. The California Energy Commission recently published report (CEC-300-2006-004) that provides evidence of this problem. This report suggests that a "*minimum* overall contract failure rate of 20–30 percent should generally be expected" and "failure rates much higher than these levels are supported by historical experience."[9] Furthermore, the CPUC recently underscored this issue in its January 2008 report to the legislature: "The slow pace of project development despite strong solicitations underscores the fact that projects face a number of challenges beyond simply getting a contract with an IOU to coming online. These barriers include, but are not limited to, transmission, permitting challenges, and developer inexperience."[10] So while Marin may make estimates of the cost of renewables under the assumption that no such problems will arise, Marin needs to be fully cognizant of the fact that these projects are quite difficult to develop and significant amounts of money can be invested into what eventually becomes a canceled project. Along with project cancellation would come the need for even more expenditures to line up sources of replacement power.

Table 4 reports the annual resource build-out for Marin. The loads reported in the following table are end-user loads adjusted for 7 percent transmission and distribution line losses.

Table 4. PG&E's Estimate of Marin CCA's Annual Resource Build-out

Load Forecast (less Losses)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Peak (MW)	237	236	235	234	234	234	235	235	236	240	241	242	243	244	246
Energy (GWh)	1256	1252	1253	1257	1261	1266	1272	1277	1284	1288	1295	1302	1308	1314	1321
Resource Adequacy (MW)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Combined Cycle	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Gas Turbine	153	151	150	99	99	99	100	100	101	106	107	108	110	111	113
Biomass	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50
Wind (New Development)	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150
Wind (Power Purchase Agreement)	436	435	435	186	188	189	192	194	196	199	201	204	206	209	211
Total RA Contributing Resources	273	271	270	269	269	269	270	270	271	276	277	278	280	281	283
Planning Reserve Requirement 15%	273	271	270	269	269	269	270	270	271	276	277	278	279	281	283
Renewable Energy (GWh)	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Biomass	0	0	0	346	346	350	348	347	347	347	347	348	348	348	346
Wind (New Development)	0	0	0	304	304	304	304	304	304	304	304	304	304	304	304
Wind (Power Purchase Agreement)	884	882	882	376	380	384	389	393	398	403	407	413	418	423	429
Total Renewable Energy (GWh)	884	882	882	1026	1030	1038	1040	1044	1049	1054	1058	1064	1069	1075	1078
RPS Goal (GWh)	703	701	702	880	883	886	890	894	899	902	907	911	915	920	925
RPS %	70.4%	70.5%	70.4%	81.7%	81.7%	82.0%	81.8%	81.8%	81.7%	81.8%	81.7%	81.8%	81.8%	81.8%	81.6%

iii. *Treatment of Renewable Energy Additions*

As noted earlier, Marin targets meeting 70% of its energy needs from renewable energy starting in 2011 and 81% of its energy needs from renewable energy starting in 2014. From 2011 to 2013, Marin has identified that it will meet renewable energy targets using generation primarily from renewable power purchase contracts. From 2014 through 2025, Marin has reported that it will develop wind (150 MW) and biomass (50 MW) resources and will meet the remainder of its 81% renewable target with supplemental renewable power obtained via PPAs.

[9] California Energy Commission – Building a "Margin of Safety" Into Renewable Energy Procurements: A Review of Experience with Contract Failure, January 2006, p.42

[10] CPUC – RPS Procurement Status Report, January 2008 – p.4.

iv. *Gas Prices*

Since the non-renewable portion of the Marin power portfolio would need to be met via conventional supplies (which are assumed to be natural gas-fired plants), PG&E used two publicly available forecasts of natural gas prices in this analysis. For the first two years of the analytic period, when market prices are available from the New York Mercantile Exchange (NYMEX) the NYMEX Henry Hub futures strip was used.[11] For the 2013–2025 period for which NYMEX prices are not available, the CPUC's California gas price forecast that underlies its MPR electric forecast was used. Table 5 presents this gas price forecast, which was utilized as the fuel cost input for gas-fired generation in the simulation model. These same gas prices were used to produce the spot market price forecast to simulate spot electricity sales and purchases in the Marin analysis.

Table 5. NYMEX and MPR Gas Forecast

Year	California Burner Tip Natural Gas Forecast (Nominal$/mmBtu)	Source
2011	8.45	NYMEX Futures Strip
2012	8.36	NYMEX Futures Strip
2013	8.07	CPUC MPR
2014	7.99	CPUC MPR
2015	7.91	CPUC MPR
2016	7.82	CPUC MPR
2017	8.13	CPUC MPR
2018	8.23	CPUC MPR
2019	8.47	CPUC MPR
2020	8.78	CPUC MPR
2021	8.95	CPUC MPR
2022	9.22	CPUC MPR
2023	9.49	CPUC MPR
2024	9.78	CPUC MPR
2025	10.00	CPUC MPR

Source: California Public Utilities Commission and NYMEX

v. *Capital Cost Assumptions for Resource Additions*

PG&E used capital cost estimates for resource additions from two sources. The first source was the California Energy Commission (CEC) Cost of Generation (COG) Model (Beta Version 9). Using the CEC's COG model, levelized capital costs were drawn using municipal utility financing assumptions. The financing rate for municipal financing assumed by the CEC is 4.35%. As PG&E described in its October 2007 response to Marin's September 2007 preliminary business plan, the muni rate – whether 4.35% or 5.5% as employed by the BP -- is likely unrealistically low for a prospective CCA, since traditional

[11] The NYMEX Henry Hub futures prices were obtained from Global Energy's data warehouse solution, Energy Velocity, on December 5, 2007. To estimate the burner tip gas price for California generators, the basis differentials between the Henry Hub and California natural gas price were taken from the CPUC MPR Report (October 2007) and added to the NYMEX Henry Hub price for the years 2011 - 2012.

municipal entities serve captive customers who do not have the ability to opt-out. Because a CCA would face the risk of customer opt-out the borrowing rate for CCA investments in generating assets would likely to be higher than for similar investments by municipal utilities with captive customer bases. Furthermore, given the fact that the Marin BP indicates that the Marin CCA would be buying much of its power under a PPA, such costs would not benefit from lower municipal financing rates. Therefore, the costs presented herein – and in the BP - - are optimistically low.

For wind power, the PG&E team assumed an installed cost of $2,500/kW (which includes land and transmission interconnection), with no renewable energy production tax credit (REPTC), and a 23 percent annual capacity factor. This higher assumption regarding installed costs is based on recent findings of increased construction costs of wind generation in California. For example, LADWP has recently indicated that it will pay $425 million to construct a 120 MW wind farm in the Tehachapi, California. This is over $3,500/kW, and in this respect PG&E's $2,500/kW assumption is conservative.

The 23 percent capacity factor assumption is based upon actual metered deliveries of wind power to PG&E in 2003. It is unlikely that Marin will be able to access Class 5 wind in California, particularly in Northern California. For example, according to Solano County staff, all but 7,500 acres of the Solano Wind Area is already developed or committed to other developers. The remaining acreage is on the edge of the Wind Area and is thus likely to have lower quality wind than the already–developed land. Furthermore, Southern California Edison (SCE) recently filed a contract at the CPUC for a wind project at Daggett Ridge with a 28% capacity factor (79.5 MW and 197 GWh/yr). In response to a protest to its filing by TURN, SCE noted that "many of the best wind locations in California have already been developed or are in the process of being developed. As a result, sites with lower capacity factors, like the Daggett Wind site, are being developed."[12]

While Marin's BP assumes biomass costs of $65 to $85/MWh, PG&E believes it is more realistic that the price for this type of resource will be much higher, based upon evidence that the CPUC's adopted MPR has been setting the competitive (market clearing) price, and in many cases projects are now coming in at much higher costs. In fact, according to the E3 Consulting Group[13] and the California Energy Commission report, these costs are pegged at over $100/MWh.[14] In any event, it is more realistic to assume that any entity in possession of low-cost biomass resources will be mindful of the opportunity to sell its resource at a price reflective of competitive market revenues, rather than simply reducing power costs to CCA customers.

Table 6 summarizes the capital cost estimates used in assigning costs to the gas-fired and wind resources included in this analysis.

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[12] "Reply of Southern California Edison Company to The Utility Reform Network and the Division of Ratepayer Advocates Protests of Advice 2198-E, Submission of Contracts for Procurement of Renewable Energy" dated January 29, 2008.
[13] CPUC GHG Modeling, "New Biomass and Biogas Generation Resource, Cost, and Performance Assumptions" Oct. 25, 2007.
[14] California Energy Commission, "Comparative Costs of California Central Station Electricity Generation Technologies" dated December, 2007.

Table 6. PG&E's Capital Cost Assumptions for Gas-Fired and Wind Generation (2007)

Technology	$/kW-yr	Source
Marin Wind Development	223	Global Energy
Combined Cycle	85	CEC COG Model
Gas Turbine	94	CEC COG Model

The second cost estimate source used in this analysis is the CPUC's MPR which sets forth a reasonable price benchmark for entities to procure renewable energy under long term contracts. Table 7 summarizes the MPR price used in costing the renewable power in this analysis.

Table 7. PG&E's Renewable PPA Cost Assumptions – MPR (Nominal $)

Technology	$/mWh	Source
Wind - Power Purchase Agreement	96	CPUC - MPR
Biomass	96	CPUC - MPR

vi. Other System Costs and Administrative and General Costs

Table 8 below reports the cost assumptions for ancillary service fees, CAISO Grid Management Charge, and Administrative and General Costs. Ancillary service costs were estimated at $1 per MWh of load. This is based on information from monthly ancillary service costs in the California ISO Market Performance Reports; the ancillary service costs averaged to $0.94/MWh for 2006 and $0.96/MWh for 2005. Grid Management Charges were estimated at $0.70 per MWh of load, based on current CAISO rates. In addition, PG&E added a $0.10 per MWh cost for wind integration that the CAISO currently charges for wind generation. Administrative and General Costs were taken from the Marin BP for the years 2011 through 2013. From 2014 onwards, PG&E escalated the costs by 2.5 percent annually.

Table 8. PG&E's Estimates of Other System and A&G Costs (Nominal $)

Other System Costs		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ancillary Service Fees	($000)	1,308	1,304	1,305	1,309	1,314	1,319	1,325	1,330	1,337	1,342	1,349	1,356	1,362	1,369	1,376
ISO Grid Management Charge	($000)	914	911	912	914	918	921	925	929	934	937	942	947	951	956	961
Operations & Scheduling Coordination	($000)	6,540	6,520	6,525	6,545	6,570	6,595	6,625	6,650	6,685	6,710	6,745	6,780	6,810	6,845	6,880
Wind Integration Costs	($000)	88	88	88	68	68	69	69	70	70	71	71	72	72	73	73
Total Other System Costs	($000)	8,850	8,824	8,830	8,837	8,870	8,904	8,945	8,979	9,026	9,060	9,107	9,155	9,195	9,243	9,290
Administrative and General Costs																
Staffing	($000)	3,093	3,186	3,281	3,363	3,447	3,533	3,622	3,712	3,805	3,900	3,998	4,098	4,200	4,305	4,413
Infrastructure	($000)	158	162	167	171	176	180	184	189	194	199	204	209	214	219	225
Contractor Costs	($000)	2,609	2,635	2,714	2,782	2,852	2,923	2,996	3,071	3,148	3,226	3,307	3,390	3,475	3,561	3,650
IOU Fees (Including Billing)	($000)	1,128	1,025	1,056	1,082	1,109	1,137	1,165	1,194	1,224	1,255	1,286	1,318	1,351	1,385	1,420
Contract Staff	($000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total A&G	($000)	6,987	7,008	7,218	7,398	7,583	7,773	7,967	8,167	8,371	8,580	8,794	9,014	9,240	9,471	9,707

d. Simulation Results:

Table 9 reports Marin's simulated annual system total costs, total billed load, and the $/MWh cost of serving load. The costs reported in this table include the annual levelized capital costs for the resources used in Marin's portfolio based on the capital cost assumptions provided above. Ancillary service fees, CAISO grid management fees, and administrative and general fees are also included in the cost figures in this table.

Table 9. Summary of PG&E's Simulation Results

Year	Total CCA Cost ($000 - Nominal)	Total Billed Load (GWh)	Total CCA Cost ($/MWh)
2011	156,916	1,256	125
2012	155,707	1,252	124
2013	151,425	1,253	121
2014	164,706	1,257	131
2015	164,615	1,261	130
2016	165,457	1,266	131
2017	166,521	1,272	131
2018	166,852	1,277	131
2019	168,275	1,284	131
2020	169,566	1,288	132
2021	170,921	1,295	132
2022	172,055	1,302	132
2023	173,826	1,308	133
2024	175,393	1,314	133
2025	176,581	1,321	134

Table 9 shows costs per MWh remaining the same for several years after a significant increase in 2014 associated with owning 150 MW of wind and 50 MW of biomass. Since Marin's load is essentially flat for the years after 2014, wind cost is levelized and thus does not change. The remaining costs do not escalate much (e.g., a few of them rise at 2%/year).

The Table in Appendix 1 shows the detailed results of Global Energy's analysis.

3. PG&E's Generation Rates

One of the most important factors, in determining whether Marin customers would save with a CCA is the future magnitude and rate of change of PG&E's generation rate. The BP acknowledges this on p.77, stating "Small differences in the escalation rate of PG&E's generation rates would have significant impacts on the ability of the CCA Program to provide ratepayer benefits." But the BP then goes on to mischaracterize and confuse the issue in an apparent attempt to justify the use of a very high forecast of future PG&E generation rates (which, of course, makes it appear easier to reach a conclusion that Light Green option customers will pay rates equivalent to PG&E's and 100% Green customers will pay rates just 20% higher than PG&E's). Specifically, the BP states:

> "The forecast underlying this business plan projects an average increase of 3% per year in PG&E's generation rates, which is relatively low by historical standards. The average annual increase in PG&E's electric rates has been 4.1% since 1980 and 5.2% since 2000." (p.77)

This statement is erroneous and misleading for a couple of reasons. First of all, as the 2014– 2025 pro forma makes clear, the BP assumes that rates increase by 3.5% per year, not 3%.[15] Second, the statement about the 4.1% increase since 1980 cannot possibly refer to PG&E's generation rate, but instead seems to be referring to PG&E's total bundled rate. But the historical and future levels of bundled rates are completely irrelevant to the issue of whether or not customers will save on CCA, since customers pay the same non-generation rate components (i.e., delivery and non-bypassable charges) whether they choose to be served by the CCA or opt out and continue as PG&E bundled service customers. The only PG&E charge that will be avoided by CCA customers is the generation rate, so it is the only relevant charge to use as a standard of comparison for the CCA's expected rates. PG&E only began unbundling its rate into its various components (generation, transmission, distribution, public goods, etc.) in 1998, so data on generation rates only date back 10 years.[16]

In fact, PG&E's generation rates that would be avoided by customers served via a CCA have increased by only about 1 to 2 percent per year between 1998 (the year rates were initially unbundled) and 2007. Marin's consultant, Navigant, made similar misstatements about PG&E's historical generation rates in public meetings held to persuade elected officials to the support efforts of the Kings River Conservation District (KRCD) and San Joaquin Valley Power Authority (SJVPA) to move forward with their CCA plan. Over the course of six months from July through December, 2007, PG&E sent a series of letters to SJVPA and KRCD responding to Navigant's misstatements and documenting the lower, 1 to 2 percent per year, historical increases in PG&E's generation rates. In Appendix 2 PG&E has attached that correspondence. Furthermore, as PG&E pointed out to Navigant in its correspondence, the forecast for annual generation rate increases that PG&E provided to the CEC as part of the Integrated Energy Policy Report range from approximately 0.5% to 2.5%. PG&E has chosen the mid-point of both of these ranges – 1.5% -- as part of this analysis.

One other important factor that needs to be accounted for is that PG&E's generation rate that would be avoided by a CCA may be overstated to the extent it includes the above-market costs of so-called "new world procurement" contracts. The California Public Utilities Commission (CPUC) has previously determined in decisions D.04-12-048 and D.06-07-029 that PG&E may recover, via non-bypassable charges, any costs of long-term procurement contracts entered into since 2004 that turn

[15] The Assumptions Sheet also lists the escalation in PG&E generation and CCA rates at 3.5% per year.

[16] PG&E suspects that the 5.2% figure also refers to bundled rates, since the BP provides no supporting documentation for this claim. In addition, the choice of 1980 as a starting point seems curious. Why go back 28 years? Why not go all the way back to 1950? Or why pick 2000 (the year before the energy crisis) rather than 2001 (the year after) as a starting point? PG&E suspects Marin's consultant, Navigant, may have "cherry picked" its analysis periods to show PG&E historical rates in their worst light. In any event, it is only the level of PG&E's generation rate – and not its total bundled rate – that matters.

out to be above the market price. The new world procurement charges will apply to all departing customers, including specifically customers who take service from a CCA.[17] The upshot is that some portion of PG&E's generation rate may be deemed to be non-bypassable and separated out as a separate charge that CCA and other departing customers will owe. For example, the PG&E generation rate for the mix of customer loads served in Marin is currently 8.3 cents per kWh. If the CPUC adopts a methodology that results in 0.3 cents of this rate being deemed to be associated with the above-market costs of new world procurement contracts, then PG&E will further unbundle its rates to show a generation rate of 8.0 cents and a new world procurement charge of 0.3 cents. In that event, the rate that a Marin CCA would have to beat for customers to see savings would be 8.0 cents, not 8.3 cents.

4. Side-by-Side Comparison Between PG&E's and the BP's Financial Analyses

a) Inconsistencies in the BP

The BP presents its pro formas in two distinct, difficult-to-meld-together tables. The BP pro forma for the initial 2009 - 2013 period (which shows estimated cash-flows) is presented as Table 3 on page 10, and again on p.67. The BP pro forma for the 2014 - 2025 period (which shows break-even CCA rates) is in BP Appendix A. As described below, these two tables are virtually impossible to meld together into a single pro forma for the entire 2009 - 2025 period because they contain widely different information. There are different levels of detail in the two tables, and some costs items appear in one table but not the other. Neither table provides sufficient detail for an independent observer to replicate the results.[18]

On the revenue side, the BP pro forma in Appendix A (2014–2025) provides annual estimates by customer class of accounts, sales, and rates in addition to the revenue estimates. In contrast, Table 3 (2009-2013) provides estimates only of annual revenue, with no detail on number of accounts, sales, or rates by class or in the aggregate. This lack of information makes it difficult to verify how the revenue estimates were derived for the 2009-2013 period. Comparing the two tables, there also appears to be an inconsistency in the revenue trend between 2013 (the last year of one table) and 2014 (the first year of the next table), with the annual revenue figure inexplicably dropping from $139 million to $128 million – despite the assumption in the BP's analysis that sales increase every year by 0.5% and rates by 3.5%. A comparison of revenue figures in adjacent years over the 2012-2025 period shows the expected 4% increases (i.e., equal to the sum of the 0.5% increase in sales and the 3.5% increase in rates) for every class and every pair of years except between 2013 and 2014, where a number of classes show significant inexplicable decreases.

On the cost side, the BP's two pro formas are also very different. The one for the initial period contains estimates of two categories of costs: (a) administrative and general (A&G) costs,

[17] The new world procurement charges will be vintaged, so that customers will be responsible only for the above-market costs of contracts entered into prior to their departure. A CPUC proceeding, Track 3 of Rulemaking 06-02-013, is nearing completion where the CPUC will adopt a specific methodology for calculating these charges and determining the precise vintaging rules.

[18] Subsequent to the release of the BP, Marin has posted on its web page a one-page document titled "January 2008 Draft CCA Business Plan for the Marin Communities—Assumptions Underlying Projected Operating Results" (henceforth called the "Assumptions Sheet") with additional information.. This Assumptions Sheet provides some helpful additional information, although in some instances the information is in conflict with the BP.

including A&G sub-component cost items, and (b) program operations, which are limited to energy procurement costs and an apparent adder to account for higher renewables costs. In contrast, the pro forma for the later period shows five categories of costs, including (a) and (b) above (although without the A&G subcomponent items) plus (c) capital and debt service costs, (d) billing costs, and (e) franchise fee costs. There is no discussion as to why the detailed information about A&G subcomponent costs was excluded from the 2014-2025 pro forma (since these costs were presumably estimated), nor why cost items (c), (d), and (e) were excluded from the 2009–2013 pro forma. Certainly, the Marin CCA would be obligated to make franchise fee payments during all years, not just 2014-2025 – so why omit these costs? Moreover, the BP states on p.11 that all three bond issuances for start-up, working capital, and for the county-owned renewable projects will have been made by 2011, so the absence of any debt service costs in the 2009 - 2013 pro forma is puzzling.

In addition to these inconsistencies between the two BP pro formas, both suffer from a lack of detail. On the revenue side only the overall average rates charged by the CCA are shown,[19] but not the separate prices charged for the 100% Green and Light Green options. On the cost side, there is a rather startling absence of detail, especially concerning power costs. The two BP pro formas each show two power related items: the 2009–2013 pro forma contains lines for "electricity procurement" and "renewable portfolio adjustment" costs; while the 2014 - 2025 pro forma lists "cost of energy" and "capital and debt coverage." The latter is primarily designed to pay back a $500 million bond used to finance the construction of wind and biomass power plants. But nowhere are individual resources identified or the calculation of their costs shown.[20] Nor is there any delineation of PPA costs. Finally, although a table on p.11 describes three proposed bond issuances in general terms, there is no description of how expected debt services on these three bond issuances combine to equal the annual debt service cost figures shown in the pro formas.[21]

b) Side-by-Side Comparison

Notwithstanding these challenges, PG&E has attempted to construct a side-by-side comparison of its assumptions and analytic results with that of the BP. Table 10 shows a comparison of key PG&E assumptions versus those made by the BP that impact the analytical results while Table 11 compares the resulting costs. A detailed comparison of the assumptions is included in Appendix 3.

[19] This comment pertains to the 2014-2025 pro forma. As noted earlier, the 2009-2013 pro forma does not show any rates at all.
[20] The Assumptions Sheet does contain some unit cost information (i.e., installed cost, O&M costs, fuel and costs). However, no calculations are shown as to how these unit costs are ultimately turned into annual energy costs.
[21] Even the basic assumptions made by the BP are unclear. For example, the exact terms of each of the three issuances are not spelled out. Rather, they are characterized in vague terms as "No longer than 7 years," "No longer than 5 years," and "20-30 years." The assumed interest rates are similarly unclear: the text in footnote 29 on p.73 says 6% (at least for the first issuance), while the Assumptions Sheet lists 5.5% as the "cost of money."

Table 10: Comparison of Key Assumptions

Assumption	Marin BP	–PG&E's/Global Energy
Full Requirements Electric Supply Cost (¢/kWh)	8.8¢	11.8¢
Wind Capacity Factor	35%	23%
$/MWh – Wind	$85 - $105	$127
Biomass Capacity Factor	80%	78%
$/MWh - Biomass	$65-$80	$96

Table 11: Comparison of Results

Year	BP's Estimated CCA Rates ($/MWh)	PG&E's/Global Energy CCA Rates ($/MWh)
2011	$88	$125
2012	$88	$124
2013	$88	$121
2014	$104	$130
2015	$100	$130
2016	$104	$131
2017	$105	$131
2018	$105	$131
2019	$107	$131
2020	$111	$132
2021	$114	$132
2022	$115	$132
2023	$117	$131
2024	$118	$133
2025	$119	$134

PG&E's estimates of the rates that Marin will need to charge CCA customers, if it supplies power with very high penetration rates of renewables, are substantially higher than the BP's estimates of these rates. Given the different nature of the two analyses, there are a large number of possible causes of these differences. It appears that the biggest driver of the difference for the years 2010-2013 is the "placeholder" estimate that Navigant made on the cost of a "full requirements" contract. As discussed elsewhere in this report, it is not possible to make a reasonable estimate of the cost of this contract without an identification of the resources that will be used to provide this power. The BP has not provided any indication of what specific resources are assumed to be used, and instead the BP simply inserts an "indicative" estimate of the cost of that supply. Part of that indicative estimate includes a presumption that the cost premium for renewable supply would be 1.5 cents per kWh, although in another recent report, Navigant (Marin's consultant) indicated that the premium is far from stable and has increased by 1.5 cents per kWh since 2004. [22] In contrast, PG&E has made assumptions about specific resources that might be used and where those resources might be located, followed by an estimate of the cost of those specific resources.

Again, with the caveat that PG&E does not have sufficient detail on the Navigant analysis for the year 2014 and beyond, it appears that the biggest drivers of the difference in the estimates are costs

[22] "Economic Impacts of the Tax Credit Expiration", Final Report Prepared for the American Wind Energy Association (AWEA) and the Solar Energy Research and Education Foundation (SEREF), Feb. 13, 2008 (available at http://www.awea.org/newsroom/pdf/Tax_Credit_Impact.pdf).

of wind and of biomass resources.[23] Regarding biomass, the Marin BP apparently assumes this will cost in the range of $65/MWh to $80/MWh. Based on higher prices reported from other sources,[24] PG&E has used a competitive market rate of $96/MWh, with the understanding that the owners of any cheaper biomass supply will want to receive this competitive market price. Any higher cost biomass supply likely will not be built, and Marin would instead be looking for alternatives that it could only hope to be able to get for something close to this competitive market price.

5. Additional Factors Impacting the BP Viability

a. Power Purchase Agreements – Fixed Prices and Risk

The BP proposes that the Marin CCA procure all of its power needs over the 2009-2013 period, and a portion of its power needs from 2013 on, via PPAs entered into with suppliers. On p.76, the BP seems to contemplate that the Marin CCA would negotiate a fixed price full requirements contract (or contracts) with a supplier (or set of suppliers).[25] The assumed advantage of this for the CCA is that the risk of possible higher future market prices (e.g., due to increasing fuel prices) would be borne by the supplier, not the CCA. But this ignores the fact that suppliers will not want to bear that risk either, unless compensated for doing so via a risk premium added to the contract. The recent example of negotiations between KRCD, the exclusive supplier for the proposed SJVPA, and Citigroup, a potential full requirements power supplier, raises questions regarding exactly how much risk is absorbed by the power provider, and how much resides with the customers. So it is not at all clear that, absent paying a hefty premium, a Marin CCA would be able to negotiate a fixed price contract for full requirements supply.

b. Availability and Price of New Renewables

In its October 2007 comments on the preliminary BP, PG&E noted that renewables are currently in great demand, prices are increasing, and many prime locations for wind power have either already been developed or reserved for development. On p.54, the BP essentially acknowledges the truth in those comments, stating, "The Authority, working with third party electric suppliers, will need to be aggressive in pursuing the renewable resources that are currently available to ensure that PG&E and the other utilities do not lock up the most economic resources for their own portfolio needs during the early years of the Program." Given the huge demand for renewables due to climate change concerns, as well as legislative and regulatory policy prescriptions, the best projects have already been developed and prices have been rapidly increasing.

One advantage often cited (and cited here, too) for public entities to develop power projects is the ability to finance them with tax-exempt bonds. In its October 2007 comments, PG&E acknowledged this potential benefit, but also noted that there is opt-out risk and that financing costs are just one element of the total cost of power supplies. PG&E will not repeat those comments here.[26] However, PG&E does comment here on the language in the BP at p.74 that states that the benefits of tax-exempt financing can be obtained even if Marin does not itself finance and construct the renewable plants – by purchasing the power at cost from plants

[23] Refer to the wind differences discussed on p.7 of this report.
[24] Refer to biomass discussion on p.7 of this report.
[25] The text states, "Once the Authority locks in the price of its initial supply contract,…" (See p.76.)
[26] See Letter dated October 26, 2007 from John Newman to Charles McGlashan, p.8.

financed by publicly owned utilities (POUs) that are eligible for similar favorable tax treatment on their bond issuances. This begs the question of why a POU would be willing to sell power at cost to Marin when the price offered by other buyers in the market is higher. The POU has a fiduciary duty to its own ratepayers to keep rates as low as possible by selling any excess power it has at the highest possible price. In this situation, Marin's CCA should expect to pay the market rate for renewable power, whether it comes from a privately owned plant or one owned by a POU.

c. Opt-Out Rate Assumptions and Proposed CCA Marketing

On p.38, the BP states that it has assumed that the opt-out rate for all non-governmental accounts is 10%. No basis is provided for this assumption, and it strikes PG&E as quite optimistic – especially given that the BP proposes that customers will be automatically defaulted onto a rate which will, at best, cost 20% more than the Light Green rate, which the BP believes will approximate PG&E's generation rate for at least the early years.[27]

In similarly predicting participation rates for its two rate options, the BP tellingly assumes that just 5% of the larger (E-19 and E-20) customers will remain with the more expensive, default, 100% Green option that is anticipated to cost 20% more than PG&E's generation rate. Apparently the BP assumes these large customers are to be price-sensitive. But if they are price-sensitive, then why would 90% of them choose not to simply opt-out, when the best option the Marin CCA is offering (Light Green) will, likely cost much more than PG&E's generation rate?

In contrast, and somewhat inexplicably, the BP assumes that 70% of medium-sized business customers will remain with the 100% Green option. Why business customers who are just slightly smaller than E-19 size would have a "take rate" for the100% Green option that is 14 times that of E-19 customers is not explained. The BP's assumption that there is a quantum difference in a customer's price-sensitivity depending upon whether its demand is above or below 500 kW does not seem credible. PG&E suspects that many more business customers are price-sensitive than the BP seems to believe, and will not be that anxious to unwittingly accept a 20% (or more) generation cost increase.[28]

d. Rate Design

On pp.81-83, in the section on rate design, the BP includes a detailed discussion of PG&E's current tiered rates for residential customers, where high usage customers pay generation rates much higher than cost while low usage customers pay below-cost generation rates. While not

[27] Since there is not yet a CCA operating in California under state rules, there is no evidence to draw from to predict opt-out behavior when customers are presented with a CCA choice versus continuing with bundled service from their investor-owned utility. Admittedly, there may be some inertia effects that favor the default CCA choice (i.e., customers not paying attention, or having the generation part of their bill being so small that it is not worth the effort to make an affirmative choice), but a 10% opt-out assumption seems entirely speculative.

[28] PG&E is aware that Marin has included a survey question about customer's willingness to pay more for renewables. But the wording of the question was misleading, since it provides no context regarding PG&E's portfolio, no notion of what a CCA does, no description of the opt-out requirements, and no sense as to cost of additional renewables. Moreover, it can be dangerous to rely too heavily on what customers say in response to a survey as a predictor of how they will actually behave when their decisions have a financial consequence. It is easy to give the more socially acceptable answer to a question when you are not actually making a financial commitment (just as it's easy for a supplier to give a low, non-binding, "indicative" bid early on, which later increases when it comes time to be firmed up). Thus Marin's lofty 81% renewables conclusion may well be misplaced.

reaching a conclusion, the BP does suggest that the Marin CCA could easily design a flat (or less severely tiered) power rate that is more cost-based and would be very attractive to large users. PG&E would just note that the utilities are well aware of the current inequities in their generation rates and have either taken steps, or are about to do so, to address the problem. Rate tiers based only on non-generation rate components were initially adopted by the CPUC for San Diego Gas and Electric (SDG&E) in D.05-12-003. SDG&E filed A.07-01-047, and subsequently a Partial Settlement in that proceeding, to continue to base rate tiers on only non-generation components. The Commission recently adopted that settlement in D.08-02-034. Late last year, Southern California Edison (SCE) filed a similar proposal with the CPUC in its Rate Design Window proceeding (A.07-12-020) to eliminate differentiation of residential generation rates by rate tier and bring them more into line with the actual cost of generation. Just recently, on January 25, 2008, The Utility Reform Network (TURN), the primary advocate for residential customers in California, filed comments in support of SCE's proposed rate design changes, stating, "There is no reason why rate design, rather than true cost differentials, should drive consumers' electric procurement choices. To the extent that there is or may be competition to provide generation services to residential customers, that competition should not be influenced by artificial incentives, but rather by the cost and value of the competing service offerings."[29]

e. Risks to Marin JPA Members

In describing the three proposed bond issuances, on p.73 the BP states that, "The security for these bonds would be a hybrid of the revenue from sales to the retail customers of the Authority, including a Termination Fee…and the renewable resource project itself." The implication is that no assets of the Marin JPA member cities and county would be at risk; the collateral would be the power plant assets of the JPA along with the revenues to be received from the CCA customers. The Termination Fee would represent insurance against the risk of customers opting-out and reducing that revenue stream. However, the first bond issuance of $6.4 million is scheduled for mid-2009,[30] which is well in advance of the opt-out deadlines for the non-governmental customers in Phases 2 and 3 (that are scheduled to occur at various times during 2010). So who is at risk for the repayment of this $6.4 million bond if it is determined that the bids received from suppliers do not meet the Marin CCA's price targets, and the CCA efforts do not proceed? Would those obligations be the responsibility of the member cities and county or would the bondholders bear the risk of default?

f. Risks to Customers

On p.86, the BP describes the Termination Fee that will be assessed to customers who, after the free opt-out period has passed and later decide they wish to return to PG&E bundled service. This Termination Fee is designed to provide a measure of protection for the Marin CCA against customer migration back to PG&E. However, the BP lacks the detail that would be helpful for customers to make reasoned decisions whether to opt out during the free period or take on the risk of a potentially hefty exit fee should they later desire to return to PG&E. According to the BP, the Termination Fee is composed of an Administration Fee plus a Cost Recovery Charge (CRC). The Administration Fee is described in detail, including a table on p.87 showing how the fee varies by customer class. But there is no detail about the CRC (which, in all likelihood, will be a much larger amount). How is a customer to make its decision, not knowing what the CRC

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[29] Response of The Utility Reform Network to SCE's Proposed Rate Design Changes, January 25, 2008, p.1.
[30] See Table 4 on p.11.

will be in the future? The BP attempts to downplay this, saying on p.87 that it "will likely not be needed." Furthermore, if it is needed, it will be set annually in open public meetings by Marin CCA board, meetings which are "subject to the Authority's customer noticing requirements."[31] The BP seems to imply that prospective CCA customers can be reassured by the fact that they'll receive notice of the annual meetings and will thus have the opportunity to be heard by the Marin CCA board. But the practical reality is that, regardless of what the public says in those meetings, the board members will have a fiduciary responsibility to set the CRC at whatever level is necessary to avoid insolvency (in fact, bondholders will likely demand such a covenant prior to investing their money).[32] CCA customers will be stuck, and have no recourse but to either remain with the CCA or pay the CRC.[33]

By law, Marin customers who do not affirmatively opt out would be automatically enrolled in the Marin CCA. Not only will CCA be the default for customers who remain silent, but the BP proposes on p.81 that such customers will default to the more expensive 100% Green CCA service option. This means that customers who are not paying attention and/or do not understand the Marin CCA's communications, will effectively be dropped onto a service where, the report itself concedes (under best case assumptions), customers will pay 20% more for electric generation, or about 10% more on their entire bill.

6. Energy Efficiency, DR, Solar and GHG Sections Introduction

a. Energy Efficiency and Demand Response

Marin's BP energy efficiency section beginning on p.55 discusses the intent for the JPA to administer energy efficiency programs as part of its CCA program. Specifically, the BP argues that there are incremental energy efficiency opportunities well beyond those that are associated with PG&E's already aggressive and comprehensive programs. The discussion seems to be designed to identify specific energy efficiency activities, along with associated costs and benefits (savings) over and above PG&E's energy efficiency programs. However, it fails to achieve anything more than providing a basic primer of how to pursue energy efficiency measures, without demonstrating that the generic measures presented in the discussion are available, achievable and cost-effective. In order to fully assess the suggested benefits, significant additional details of the proposed energy efficiency program-- their intended application, costs to the county and/or customers and anticipated energy savings will be needed. This information can then be compared to PG&E's programs to determine if there are, in fact, any incremental

[31] See p.87.
[32] In contrast, PG&E's departing load charges are set by an independent regulator, and only after lengthy proceedings where all parties have their views heard regarding the appropriate levels of the charges.
[33] The BP also states at p.74 that, "Although PG&E is under no explicit obligation to collect ongoing CCA charges [i.e., the Marin CCA's CRC] after a customer returns to PG&E bundled service, there would be little justification, if any, for PG&E to refuse to provide such a service to the Authority." It goes on to state that there is "a good precedent for such an arrangement in the case of load that has departed PG&E service for service by a municipal utility." The implication is that it is a "done deal" that PG&E can be enlisted to perform this collection. But PG&E has not agreed to do so. Moreover, the statement implying that similar arrangements are common where POUs collect NBCs for PG&E is simply wrong. Aside from two exceptional cases where PG&E agreed to sell or lease facilities to a POU, and had the leverage to negotiate such arrangements with the POU as a condition of sale/lease, POUs have not been willing to perform this billing function, and PG&E has had to undertake the collection on its own.

opportunities and benefits. Short of having such details, claims in the BP that such savings go beyond those of PG&E's, are simply not supported.

Page 56 of the BP states that for $2.8 million per year the CCA will save 15.1 million kWh, and that these are "…expanding beyond the savings achieved by PG&E's programs." However, it is not clear that BP's forecast analysis is calculated to be in addition to PG&E's program. Therefore, under the premise that the forecast analysis is adapted to supplement PG&E's programs, the following discrepancies can be found in this section:

1. Assumptions used in the BP to determine the amount and cost of energy efficiency reductions are based on earlier assumptions in this decade that are optimistic when calculated out to the future for the 2014 start date in the pro forma. Thus, the energy efficiency analysis should be updated to reflect the potential and cost basis as of 2014. This update would need to take into account the energy efficiency that would be realized during 2002 - 2013 (12 years) or 2006 - 2013 (8 years). The adjustment is likely to have a significant impact on the analysis since much of the lower cost energy efficiency will have already been realized (i.e., residential lighting), leaving less cost-effective energy efficiency available.
2. The analysis does not take into account recent Federal and State legislation raising the mandatory efficiency of general purpose lighting. As 71% of the energy efficiency market potential (shown on p.57) is from existing residential and commercial markets, and significant portions of this will be lighting, it is possible that little lighting potential will be available for programs by 2014. Thus, the BP's energy efficiency analysis should take this into account and forecast from the perspective of what will be available in 2014 and what it would cost.
3. The cost assumptions for the programs given on page 104 provide for 80% incentives and 20% administration, including marketing. This is a very aggressive assumption. In fact, if CCA residents would not have access to any PG&E program activities, this assumption is very unrealistic.
4. It appears that the CCA proposes to hire four program staff but the cost details are not provided to show where or how these costs are included.

With respect to demand response, the level of detail in the BP is insufficient to provide analysis. Given this limitation, PG&E cautions that it would be quite difficult for Marin County to meet based on the types of loads and weather conditions present in the County. Nonetheless, Marin's CCA would be obliged to follow the loading order as with all load-serving entities and also be prepared to meet any obligations under the CAISO Market Redesign and Technology Upgrade (MRTU) and ultimately the prevailing market structure.

While Marin's CCA energy efficiency and demand response plan and analysis should make clear what the relationship between PG&E and CCA programs are, PG&E emphasizes its intent to aggressively pursue all cost-effective measures in Marin County and elsewhere as part of PG&E's ongoing and diligent implementation of energy efficiency. In 2007, PG&E's energy efficiency programs helped customers in Marin County save over 25 million kWh, which translates to a reduction of 14,040 tons of CO_2 emissions. Further, the successful Local Government Partnership (LGP) between PG&E and Marin County delivered about 450 kW of peak demand reduction and approximately 2.5 million kWh of annual energy savings since its inception in late 2006 thru the end of 2007 through the Marin County Energy Watch (MCEW) partnership. The MCEW brings together five elements to provide energy efficiency services and resources to single and multifamily residential; small, medium and large commercial; and public agencies and schools in Marin County as described:

i. Marin Energy Management Team (MEMT) acts as "energy manager" for public sector agencies including local governments, school districts and special districts, and specifically addresses the difficulty of reaching smaller public sector institutions. Services include audits, technical assistance, engineering, assistance in financing and obtaining incentives, specifying and managing projects, energy accounting and reporting, procurement, peer meetings and training workshops. MEMT also integrates other state, utility, and private energy efficiency programs, filling resource gaps, and addressing specific barriers as needed to provide as comprehensive and seamless a delivery of services as possible.
ii. Small Business Energy Alliance (SBEA) provides energy audits and incentives for energy efficient lighting retrofits, air conditioning and refrigeration system tune-ups and package air conditioner system replacements for small businesses. The program works closely with the MEMT and Marin Green Business to assist with public agency and small business projects.
iii. California Youth Energy Services (CYES) provides hardware installation and energy assessments to targeted owners and renters in the Mass Market program. CYES serves single-family dwellings, 2-4 duplexes, and multifamily units.
iv. EnergyWise provides energy efficiency training and incentives to licensed sales agents and brokers and qualified home inspectors, enabling agents to recommend and inspectors to provide time-of-sale energy checkup ratings.
v. Building Tune-Up (BTU) offers retro-commissioning and retrofit services to large commercial customers and provides incentives for implementing energy efficiency measures.

Together, the LGP with Marin County and PG&E can achieve more additional savings in partnership than can either entity acting alone or creating another infrastructure to do so.

b. Distributed Generation/Solar

On p.2, the BP states: "The Authority would leverage existing state and federal incentives to achieve a targeted deployment of at least 13 MW of distributed solar (photovoltaic) systems within its boundaries by 2019." As PG&E has explained previously,[34] PG&E believes Marin County residents will install 13-14 MW of new solar installations – and likely more – whether or not Marin County forms a CCA. These installations will occur as a result of the California Solar Initiative (CSI), which is administered by PG&E in Marin County. Whether or not Marin County forms a CCA, PG&E will continue to administer the CSI. Since 2001, Marin County residents who participated in the CSI, or its predecessor programs the CEC's Emerging Renewables Program and PG&E's Self Generation Incentive Program, have already installed 8.2 MW of solar PV in Marin County. There are currently an additional 80 PG&E customers in Marin County who are in the process of installing an additional 3.3 MW.

[34] See Letter dated October 26, 2007 from John Newman to Charles McGlashan, p.13.

On p.40, the BP refers to the fact that SB 1 requires customers that participate in CSI to take TOU service, "Unlike the customers of the investor-owned utilities … customers of the Authority will not be constrained by PG&E's time of use rate structures, as the Authority may design rates at the discretion of its Board of Directors." However, the CPUC (and legislature) deferred this requirement until the utilities' next GRC (2011 for PG&E) when a solar friendly rate can be designed. So this assertion is not true today. Nevertheless, PG&E considers its E-6 rate that was negotiated with the solar parties and considered a good deal for most solar parties, compliant with the TOU requirement of SB 1. In fact, Marin residents who have installed solar generation and who are currently on a TOU rate would likely prefer that Marin County CCA also adopt a TOU rate, since PV tends to be producing power during peak periods when TOU rates would be highest. Customers who are exporting power prefer the highest value at time of export.

Additionally, PG&E notes that the BP has not been updated to reflect current program data. For example, under the "CEC Incentive" section on p. 59, the calculation assumes $2.60/Watt. The current CSI rebate for residential customers is $2.20/Watt. By 2011, when the residential load is projected to join the CCA, the CSI rebate for residential customers will be $1.90 or perhaps even $1.55. The installed cost, however, is realistic ($10,000 for a 1 kW unit). Consequently, the BP misrepresents the ability of their residential customers to install solar generation. While PG&E's customers have responded positively to the California Solar Initiative, and PG&E hopes their participation continues at today's high rates, the BP should accurately reflect the actual costs for Marin residents. At a minimum, the BP should be updated to reflect current program data.

c. Impact of Resource Plan on Greenhouse Gas

On p. 60-61, the BP discusses the impact on Marin's greenhouse gas emissions due to the displacement of PG&E's fossil resources by the CCA's renewable resources. While the BP uses a reasonable CO2 emissions rate of 400 tons per GWh for new gas fired generation, it also uses 707 tons per GWh for existing resources-- a number that is not reasonable since this CO2 emissions rate would not pass the legislated SB 1368 GHG emission performance standard and therefore could not be in PG&E's portfolio.

SB 1368 specifies an Emissions Performance Standard of 1,100 pounds of CO2 per megawatt-hour (550 tons per GWh) for all new long-term commitments for baseload generation to serve California consumers. This standard is based on the emissions of a combined cycle gas turbine plant. As such, Marin's assumption that the high emissions rate of 707 tons per GWh would remain the same through 2019 is incorrect because over time, the emissions rate of existing generation will go down as existing contracts expire and new contracts must conform to the approved Emissions Performance Standard of 550 tons per GWh. Therefore, Marin's set of "high" CO2 reduction estimates is too high, especially in the later years of its projection.

More fundamentally, the BP overestimates the impact on its greenhouse gas reductions since PG&E's certified or projected average emissions rate for our portfolio is much lower than the 400 or 707 tons per GWh emissions rates that they assume. PG&E's certified or projected average emissions rate in its long term plan range from 160.5 to 212.5 tons per GWh.

7. Conclusion

The Business Plan for Marin CCA is consistently optimistic in its underestimation of costs, overestimation of PG&E generation rates, rosy scenario of available, inexpensive renewables and enthusiasm for Marin's ability to find energy efficiency and distribution generation that PG&E could not. Yet, these assumptions are never tested by any sensitivity analyses. The Business Plan does not itself permit one to judge the consequences of the failure of any of these generous assumptions.

In fact, the Business Plan consistently underestimates how much a Marin Power Authority would have to pay for power even at a 20% renewable content without benefit of the hedges inherent in PG&E's current portfolio. The only way to keep the Light Green price at the level of the PG&E alternative would be for additional costs to be shifted to customers on Marin's 100% Green tariff, who the Business Plan already expects to charge **20% more than** other customers.

The Business Plan is predicated on an exceptionally high customer take rate for the 100% Green tariff among residential and small customers, perhaps because it is to be made the default rate. While Marin residents may have expressed a willingness to pay somewhat more for green power, there is no evidence that they would consent to such a large premium over the prices paid by their friends and business competitors elsewhere in the Bay Area, or by their Marin neighbors who opted out and remained with PG&E. A significant return to utility service, as happened in Ohio when utility rates fell,[35] is a distinct possibility. In that case PG&E would have no choice but to seek to recover from those returning customers the costs associated with the sudden increase in load, a "double whammy" when added to Marin CCA's exit fee.

[35] Stephen Littlechild, "Municipal Aggregation and Retail Competition in the Ohio Electricity Sector," Electricity Policy Research Group Working Papers, No.EPRG 07/15. Cambridge: University of Cambridge.

Appendix 1. Detailed Production Simulation Results

Marin CCA System Cost

Year	Metirc	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Peak and Energy Load																
Peak Load Incl Losses	MW	237	236	235	234	234	234	235	235	236	240	241	242	243	244	246
Energy Load Incl Losses	MWh	1,308,074	1,304,067	1,305,055	1,309,066	1,314,055	1,319,045	1,325,043	1,330,045	1,337,056	1,342,064	1,349,062	1,356,063	1,362,041	1,369,060	1,376,062
Resource Adequacy Contribution																
Gas Turbine	MW	153	151	150	99	99	99	100	100	101	106	107	108	110	111	113
Combined Cycle Gas	MW	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Biomass	MW	0	0	0	50	50	50	50	50	50	50	50	50	50	50	50
CSP Para. Trough Solar	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV Rooftop Solar	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind New Development (150 MW)	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind PPA	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total RA capacity	MW	273	271	270	269	269	269	270	270	271	276	277	278	280	281	283
RA Requirement @ 15% PRM	MW	273	271	270	269	269	269	270	270	271	276	277	278	279	281	283
Generation																
Gas Turbine	MWh	8,510	14,256	22,742	20,421	25,103	26,020	35,187	41,962	57,300	60,854	90,645	127,116	118,532	114,310	119,854
Combined Cycle Gas	MWh	501,470	492,864	524,778	569,067	580,642	575,578	583,184	602,324	628,691	647,842	703,358	706,642	724,831	728,892	742,279
Biomass	MWh	0	0	0	346,025	345,950	349,625	347,500	347,450	346,800	346,900	346,875	347,900	347,525	347,625	345,875
CSP Para. Trough Solar	MWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	MWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill	MWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV Rooftop Solar	MWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind New Development	MWh	0	0	0	303,971	303,971	304,361	303,971	303,971	303,971	304,361	303,971	303,971	303,971	304,011	303,971
Wind PPA	MWh	884,067	882,495	882,039	376,184	380,095	384,498	388,698	392,610	398,083	402,830	407,342	412,613	417,918	423,298	428,598
Spot Market Purchases	MWh	436,140	432,515	424,138	246,569	232,398	255,167	240,787	236,938	219,872	218,197	186,769	179,150	168,878	163,564	164,275
Spot Market Sales	MWh	-522,113	-518,062	-548,641	-553,171	-554,103	-576,204	-574,284	-595,209	-617,661	-638,919	-689,897	-721,329	-719,614	-712,639	-728,790
Total Generation	MWh	1,308,074	1,304,067	1,305,055	1,309,066	1,314,055	1,319,045	1,325,043	1,330,045	1,337,056	1,342,064	1,349,062	1,356,063	1,362,041	1,369,060	1,376,062
Total Renewable Energy (Without RECs)	MWh	884,067	882,495	882,039	1,026,180	1,030,016	1,038,484	1,040,169	1,044,030	1,048,854	1,054,090	1,058,187	1,064,484	1,069,414	1,074,933	1,078,444
Total Renewable Energy (With RECs)	MWh	884,067	882,495	882,039	1,026,180	1,030,016	1,038,484	1,040,169	1,044,030	1,048,854	1,054,090	1,058,187	1,064,484	1,069,414	1,074,933	1,078,444
Renewable Energy % of Billed Load	%	70%	70%	70%	81.7%	81.7%	82.0%	81.8%	81.8%	81.7%	81.8%	81.7%	81.8%	81.8%	81.8%	81.6%
Variable Costs																
Fuel Cost	($000)	29,509	29,076	30,784	32,784	33,430	32,863	35,325	37,306	41,172	44,199	50,788	55,878	57,975	59,647	62,386
VOM cost	($000)	3,403	3,323	3,168	3,185	3,310	3,255	3,547	3,676	3,964	4,187	4,411	4,830	5,014	5,123	5,266
Purchase Spot Cost	($000)	25,561	25,389	23,468	13,672	12,637	14,050	13,807	13,860	13,408	14,152	12,808	12,460	12,432	12,501	13,065
Ave Purchase Spot Cost	($/MWh)	59	59	55	55	54	55	57	58	61	65	69	70	74	76	80
Sale Spot Rev	($000)	-28,758	-29,585	-33,718	-34,467	-35,050	-36,150	-38,376	-41,100	-44,602	-48,960	-54,594	-60,298	-62,322	-64,127	-68,064
Ave Sale Spot Rev	($/MWh)	55	57	61	62	63	63	67	69	72	77	79	84	87	90	93
Emissions Cost	($000)	1	666	814	992	1,161	1,312	1,546	1,834	2,231	2,617	3,331	4,025	4,605	5,210	6,038
CAISO TAC (3.1HV+3.5LV)$/MWh	($000)															
Congestion Charge	($000)															
Net Variable Operating Cost	($000)	29,717	28,869	24,515	16,166	15,489	15,331	15,849	15,576	16,172	16,194	16,745	16,895	17,703	18,353	18,691
Resource Capital Costs																
Levelized CC Cost	($000)	10,949	10,949	10,949	12,086	12,086	12,086	12,086	12,086	12,086	12,086	12,086	12,086	12,086	12,086	12,086
Levelized Biomass Cost	($000)	0	0	0	33,218	33,211	33,564	33,360	33,355	33,293	33,302	33,300	33,398	33,362	33,372	33,204
Levelized Landfill Cost	($000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Levelized CSP Para. Trough Solar Cost	($000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Levelized Geothermal Cost	($000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Levelized GT Cost	($000)	15,542	15,338	15,237	11,100	11,100	11,100	11,212	11,212	11,325	11,885	11,997	12,109	12,334	12,446	12,670
Levelized PV Rooftop Solar Cost	($000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Levelized Wind New Development Cost	($000)	0	0	0	39,787	39,787	39,787	39,787	39,787	39,787	39,787	39,787	39,787	39,787	39,787	39,787
Levelized Wind PPA Cost	($000)	84,870	84,719	84,676	36,114	36,489	36,912	37,315	37,691	38,216	38,672	39,105	39,611	40,120	40,637	41,145
Total Resource Capital Costs	($000)	111,361	111,007	110,862	132,305	132,673	133,449	133,760	134,131	134,706	135,732	136,275	136,991	137,689	138,327	138,892
Other System Costs																
REC cost 5%load*$15/MWh	($000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ancillary Service Fees	($000)	1,308	1,304	1,305	1,309	1,314	1,319	1,325	1,330	1,337	1,342	1,349	1,356	1,362	1,369	1,376
Exit Fees	($000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISO Grid Management Charge	($000)	914	911	912	914	918	921	925	929	934	937	942	947	951	956	961
Operations & Scheduling Coordination	($000)	6,540	6,520	6,525	6,545	6,570	6,595	6,625	6,650	6,685	6,710	6,745	6,780	6,810	6,845	6,880
Franchise Fees	($000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind Integration Costs	($000)	88	88	88	68	68	69	69	70	70	71	71	72	72	73	73
Total Other System Costs	($000)	8,850	8,824	8,830	8,837	8,870	8,904	8,945	8,979	9,026	9,060	9,107	9,155	9,195	9,243	9,290
Administrative and General Costs																
Staffing	($000)	3,093	3,186	3,281	3,363	3,447	3,533	3,622	3,712	3,805	3,900	3,998	4,098	4,200	4,305	4,413
Infrastructure	($000)	158	162	167	171	176	180	184	189	194	199	204	209	214	219	225
Contractor Costs	($000)	2,609	2,635	2,714	2,782	2,852	2,923	2,996	3,071	3,148	3,226	3,307	3,390	3,475	3,561	3,650
IOU Fees (Including Billing)	($000)	1,128	1,025	1,056	1,082	1,109	1,137	1,165	1,194	1,224	1,255	1,286	1,318	1,351	1,385	1,420
Contract Staff	($000)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total A&G	($000)	6,987	7,008	7,218	7,398	7,583	7,773	7,967	8,167	8,371	8,580	8,794	9,014	9,240	9,471	9,707
Total System Costs	($000)	156,916	155,707	151,425	164,706	164,615	165,457	166,521	166,852	168,275	169,566	170,921	172,055	173,826	175,393	176,581
Billing Load	MWh	1,255,751	1,251,904	1,252,853	1,256,703	1,261,493	1,266,283	1,272,041	1,276,843	1,283,574	1,288,382	1,295,100	1,301,821	1,307,559	1,314,298	1,321,020
Gen Charge	$/MWh	125.0	124.4	120.9	131.1	130.5	130.7	130.9	130.7	131.1	131.6	132.0	132.2	132.9	133.5	133.7

Appendix 2

PG&E-SJVPA-KRCD Correspondence regarding PG&E's Generation Rates

KRCD
Kings River Conservation District

DAVID RUBIN
JUN - 6 2007

4886 East Jensen Avenue
Fresno, California 93725

Tel: 559 237 5567
Fax: 559 237 5560

www.krcd.org

May 29, 2007

Mr. David Rubin, Manager
Pacific Gas & Electric Company
123 Mission Street, Room 2463
San Francisco, CA 94105

Re: Data Request from Clovis Workshop

Dear Mr. Rubin:

At the City of Clovis (Clovis) workshop on May 14, 2007 the City Council requested that Pacific Gas and Electric Company (PG&E) provide the San Joaquin Valley Power Authority (Authority) and the Kings River Conservation District (KRCD) with historic PG&E generation rates. At that meeting you stated that PG&E would be pleased to forward such information to us. Please consider this to be a formal request for any official information that provides a summary of historic PG&E generation rates as stated to the Council.

We understand, based upon our conversation outside the Council Chambers that evening, that it is only recently that PG&E unbundled rates to break-out the generation component; but we would appreciate all information that you can provide. Specifically, we are requesting system-wide generation rates and individual customer class generation rates. Thank you for your timely response to this request.

Sincerely,

David Orth
General Manager

DO/dp

CC: Robert Ford, City of Clovis

107-3160
Item 532.02

July 17, 2007

Mr. David Orth
General Manager
Kings River Conservation District
4886 East Jensen Avenue
Fresno, CA 93725

Re: Data Request from Clovis Workshop

Dear Mr. Orth:

This is in response to your letter of May 29, 2007 (which I received on June 6), in which you requested additional information about PG&E's historic unbundled generation rates. PG&E has stated in its presentations (at the Clovis Workshop on May 14, 2007 and subsequently) that the generation component of its rate, which has been unbundled only since 1998, has grown at approximately two percent per year since 1998, the first year in which there was a separately identified generation charge. This was in direct response to KRCD's presentation that same evening, and the SJVPA letter sent to the Fresno City Council dated May 14, that claimed that PG&E's generation rate had grown by over 4% per year for a 27 year historic period.

You have asked for "any official information that provides a summary of historic PG&E generation rates as stated to the Council," and also asked, "Specifically, we are requesting system-wide generation rates and individual customer class generation rates." I must caution that there have been numerous changes in how the various components of PG&E's unbundled rates have been defined and tracked for reporting purposes over the period since 1998. That being said, following is the information that supports our claims.

At the system-wide level, the annual compounded growth rate between 1998 and 2007 for PG&E's average generation rate has been between 1.5% and 2.3%, with differences depending on what methods are used to reconcile the structural changes in the ways that PG&E's unbundled rates have been defined over time:

Method 1: Broader Definition of System Average Generation Rates

- 1998 Generation Rate = 6.76 cents/kWh
- 2007 Generation Rate = 7.71 cents/kWh
- Compound growth rate = 1.5% per year

Method 2: Narrower Definition of System Average Generation Rates

- 1998 Generation Rate = 6.29 cents/kWh
- 2007 Generation Rate = 7.70 cents/kWh
- Compound growth rate = 2.3% per year

For both methods, the compound annual growth rate has been calculated using the formula:

- Compound growth rate = [(2007 Rate – 1998 Rate) ^ (1/9)] - 1 ,

where the exponent (1/9) reflects the number of years between 1998 and 2007.

Method 1 includes adjustments to 1998 generation revenues to account for the 10 percent rate reduction bond discounts provided to residential and small commercial customers as if those discounts had not been applied to 1998 rates. (Revenues were tracked on this basis for the period between 1998 and 2000 as a means of tracking class-level contributions towards electric restructuring transition costs, with the 10% rate reduction discounts recognized as having changed the timing of when these costs would be paid by residential and small commercial customers, but not the total level of those costs.) Method 2 includes no such adjustment. Additionally, the Method 1 rates for 2007 include the 2007 Reliability Services rate component (which is currently treated as a transmission-related rate, but which was not separately unbundled from generation rates until the year 2000). Method 2 does not.

Please refer to Tables 1 and 2 for a year-by-year history of PG&E's unbundled generation rates from 1998 to 2007, based on Methods 1 and 2 respectively.

Sincerely,

Original signed by David Rubin

cc: Robert Ford, City of Clovis

Table 1 – Historic System Average Bundled Generation Rates (Method 1)

	System ($/kWh)
Gen Rate -- 1998	$0.0676
Comparable Gen Rate -- 2007	
Gen rate component	$0.0748
CTC	$0.0001
RS	$0.0001
FTA	$0.0034
RRBMA	-$0.0013
Total	$0.0771
Annual growth rate	1.5%

Table 2 – Historic System Average Bundled Generation Rates (Method 2)

Calendar Year	Data Source	Gen+CTC+ FTA/RRBMA $/kWh
1998	Recorded	0.06292
1999	Recorded	0.06207
2000	Recorded	0.05966
2001	Recorded	0.08709
2002	Recorded	0.09798
2003	Recorded	0.08886
2004	Recorded	0.07160
2005	Projected	0.06815
2006	Projected	0.07589
2007	Projected	0.07698

NAVIGANT
CONSULTING

To: David Orth
Kings River Conservation District

From: John Dalessi
Navigant Consulting, Inc

Subject: Review of Rate Information Provided by PG&E

Date: July 27, 2007

Dear Mr. Orth,

At your request, I have reviewed the historical rate information provided by PG&E in the July 17, 2007 letter to you from Mr. David Rubin. In this letter, Mr. Rubin cautions that "there have been numerous changes in how the various components of PG&E's unbundled generation rates have been defined and tracked for reporting purposes over the period since 1998", and he presents two different methods for reporting PG&E's historical generation rates.

According to Mr. Rubin, the PG&E system-wide average generation rate in 1998 was either 6.76 cents per kWh or 6.29 cents per kWh. The difference is attributable to how the 10% rate reduction bond discounts provided to residential and small commercial customers are accounted for in 1998 rates. The higher rate of 6.76 cents per kWh includes an adjustment to remove the impact of the 10% rate reduction bonds, while the lower rate of 6.29 cents per kWh is the unadjusted generation rate from 1998.

Mr. Rubin likewise reports that PG&E's system-wide average generation rate in 2007 is either 7.71 cents per kWh or 7.70 cents per kWh, depending upon whether one includes certain reliability services costs that were formally classified as generation but that are now classified as transmission. With these two different methods, Mr. Rubin reports an average annual generation rate increase of either 1.5% or 2.3% from 1998 through 2007, depending upon how PG&E defines the generation rate.

It is important to understand what generation costs are not included in the "generation" rate history provided by PG&E. PG&E's reported 2007 generation rate does not include two categories of generation costs that total approximately $590 million in the 2007 rates The excluded generation costs include $260 million in PG&E debt payments for unrecovered electricity procurement costs from the 2000-2001 period and $330 million in

California Department of Water Resources (DWR) debt payments for similar unrecovered generation related costs incurred when the DWR temporarily assumed responsibility for procuring electricity for PG&E customers when PG&E became unable to do so. These generation costs are reflected in separate charges on PG&E customers' bills, labeled the Energy Cost Recovery Amount and the DWR Bond Charge.

Failure to include these costs in the analysis of PG&E's historical generation rate performance introduces a downward bias in the calculation of the average rate increases as reported by PG&E. It would be appropriate to exclude these past generation costs only if the rate analysis uses a starting point after PG&E's emergence from bankruptcy in 2003 so that annual changes in generation rates can be evaluated on a consistent basis, without the impact of the energy crisis and changes in regulatory accounting distorting the comparison. However, PG&E chose to begin its analysis with a 1998 starting point. Therefore all generation costs incurred during the period from 1998 – 2007 should be included in the analysis, regardless of whether some of these costs have be renamed under a separate rate component.

Table 1 shows that when all generation costs are included, the figures provided by Mr. Rubin indicate that PG&E's system-wide generation rate has increased by an average rate of 3.4% per year from 1998-2007.

Year	PG&E Reported Generaton Rate "Method 2"	Energy Cost Recovery Amount	DWR Bond Charge	Actual PG&E Generation Rate
1998	0.06292	-	-	0.06292
2007	0.07698	0.00337	0.00432	0.08467
Annual growth rate				**3.4%**

In addition, Mr. Rubin's letter does not acknowledge PG&E's recent CPUC filing requesting an additional generation rate increase of $540 million for 2008. Once this rate increase goes into effect, the annual growth rate in PG&E's generation rates from 1998-2008 as described above would be 3.8% per year. This figure is close to the long-term historical growth trend in PG&E's rates of 4% and well-above the 2% projected increase in the Authority's rates.

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September 21, 2007

Dear SJVPA Board Member:

The purpose of this letter is to respond to the memorandum titled "Review of Rate Information Provided by PG&E," sent by John Dalessi of Navigant Consulting, Inc. (Navigant) to David Orth of Kings River Conservation District on July 27, 2007, and discussed at the August 23, 2007 SJVPA Board meeting.

Mr. Dalessi's memorandum notes that PG&E's 2007 generation rate figure of 7.70 cents per Kwh does not include costs associated with either PG&E's debt payments (for unrecovered electricity crisis procurement costs) or DWR's similar energy crisis-related costs, and concludes that this exclusion "introduces a downward bias" in PG&E's demonstration of its generation rates. Mr. Dalessi's assertion that PG&E's appropriate exclusion of these costs represents a "downward bias" is wrong.

The two charges at question -- the Energy Cost Recovery Amount and the DWR Bond Charge -- are non-bypassable, which means PG&E collects them from all customers, whether they take bundled service from PG&E or service from a CCA. Since these charges will apply to all customers, whether they take SJVPA service or opt out and remain with PG&E, the charges are not relevant to PG&E's 2007 generation rates (or to SJVPA's rates) and should not affect any customer's decision about which generation provider to select. Consequently, it is entirely appropriate that these costs be excluded from calculations of PG&E's generation rates as they relate to CCA. More importantly, including these charges only for PG&E in a PG&E vs. SJVPA CCA rate comparison would be completely misleading.

Rather, the relevant comparison is between PG&E's generation rate *exclusive of these charges* and the generation rate offered by SJVPA also exclusive of these charges. In fact, page 59 of SJVPA's revised Implementation Plan notes that the estimates of the IOU and projected SJVPA rates "…are shown for generation services only, net of the cost responsibility surcharge that the Authority's customers will pay directly to PG&E and SCE." Including these costs in the analysis, as Mr. Dalessi appears to recommend, would mislead those customers considering CCA, since such an inclusion only for PG&E would bias the results and suggest that prospective CCA customers can expect to see unrealistically higher annual increases if they remain bundled PG&E customers.

Additionally and somewhat oddly, Mr. Dalessi states that my July 17 letter providing you with PG&E's historical rate information "does not acknowledge PG&E's recent CPUC filing requesting an additional generation rate increase of $540 million" in 2008. As you will recall, I provided my analysis in response to your request for information about current versus historical generation rate levels, and was specifically responding to KRCD's and its consultant's inaccurate claims that PG&E's recorded historical generation rates had increased by 4% per year. Nonetheless, to the extent that Mr. Dalessi wishes to bring future year estimated rate changes into the discussion, it is more appropriate to consider a multi-year forecast, such as that which PG&E presented to a number of cities in the Fresno area in the June/July timeframe, and not isolate the discussion to one year's proposed change – particularly one that reflects dry year hydro conditions. In this regard, PG&E's 9-year forecast submitted to the California Energy Commission shows a range of generation cost increases from 0.5% to 2.4%, depending on values assumed for certain input variables. However, even adding the projected 2008 increase to the data shown in my July 17 letter results in a compound annual increase over the 1998 – 2008 timeframe of only 1.9% for Method 1 and 2.6% for Method 2. It should also be noted that, depending on pending CPUC rulings, some portion of the 2008 generation costs may be deemed non-bypassable, and thus not avoided by the SVJPA CCA.

In summary, we appreciate the opportunity to provide these helpful clarifications, and look forward to continuing to discuss these important matters with you. We believe, and expect that all parties would agree, that this matter is far too important to potential CCA customers to be anything but perfectly clear when making comparisons of rates.

Sincerely,

David E. Rubin

cc: David Orth
John Dalessi

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November 7, 2007

SJVPA Board Member:

As I foreshadowed in my October 25 letter commenting on SJVPA's August 2007 revised Implementation Plan, there will be changes to PG&E's expected generation rates for 2008.

Attached is a copy of an updated filing PG&E made today with the CPUC in its 2008 Energy Resource Recovery Account (ERRA) Forecast Proceeding. The figures filed today update the preliminary figures PG&E filed in June in our initial ERRA application, based upon current estimates of PG&E's 2008 generation costs and year-end 2007 amounts in generation balancing accounts.

Our June ERRA filing showed an increase in PG&E's generation revenue requirement (including the Ongoing CTC revenue requirement) of $542 million. In contrast, today's update shows a much smaller (by $210 million) increase of $332 million. Moreover, PG&E expects to see a sizable further decrease in the overall generation revenue requirements due to a reduction in the DWR revenue requirement allocated to PG&E. A proposed decision on the DWR revenue requirement is expected to be forthcoming from the CPUC sometime between now and November 20, with a final decision issued before the end of the year.

The combined effect of these changes in generation revenue requirement will be reflected in a greatly reduced January 1, 2008 generation rate compared to what was shown in PG&E's initial ERRA filing in June. In addition, as noted in my October 25 letter, there will be rate effects resulting from reallocating revenue responsibility among customer classes in compliance with CPUC Decision 07-09-004 in Phase 2 of PG&E's 2007 General Rate Case.

We will continue to keep you informed of these and other developments and will provide you with updated forecasts of PG&E's generation rates as soon as those become available, so that you can use the most accurate information as you adjust rates for the SJVPA CCA program.

Sincerely,

David E. Rubin Jr

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December 5, 2007

SJVPA Board Member:

In my November 7, 2007 letter to you, I described the filing PG&E made earlier that day at the California Public Utilities Commission (CPUC) in our Energy Resource Recovery Account (ERRA) Forecast Proceeding. That filing updated PG&E's expected 2008 generation cost, reducing it by $210 million compared to the $542 million increase PG&E initially projected in June 2007. I also noted that PG&E expected to see a further decrease in its generation cost due to a reduction in the portion of the California Department of Water Resources' (DWR's) costs allocated to PG&E. I promised to continue to keep you informed about these changes, so that you can use the most accurate information as you adjust rates for the SJVPA CCA program. This letter provides such an update.

What has happened recently at the CPUC?
Two annual proceedings affecting utility generation costs, and therefore rates, are underway at the CPUC. On November 20, 2007, the CPUC issued a proposed decision regarding the magnitude of DWR's costs and the allocation to the three California utilities. This proposed decision would reduce the DWR costs allocated to PG&E by $148 million (when forecast balancing account amounts are included). In the ERRA proceeding, however, a delay in issuing the proposed decision means that PG&E expects that only about $67 million of the decrease described in my November 7 letter (relative to the originally filed figure in June 2007) will occur on January 1, 2008. A decrease of about $128 million (including forecast balancing account amounts) is expected to follow on March 1, 2008.

What does this mean for PG&E's system-wide generation rates?
PG&E has designed rates based upon the expected January 1, 2008 generation revenue requirement[1]; the result is a 7.4 cents per kWh average system-wide generation rate based upon the usage characteristics of all of PG&E's customers, along with an ongoing competitive transition charge rate of approximately 0.4 cents per kWh. The sum of these two rates results in a system-average estimate of 7.8 cents per kWh, on January 1, 2008. The expected reductions in March 2008 will lower this by 0.16 cents per kwh. This can be further adjusted consistent with my July 17, 2007 letter to David Orth (see attached) by adding reliability services and Fixed Transition Amount (FTA) related components[2] in order to estimate the average annual generation rate increase for the 1998 – 2008 timeframe. The results vary from 1.0% to 1.9% (using Method 1 and Method 2, respectively), dropping from the 1.5% to 2.3% shown in that letter.

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[1] These rates also incorporate the changes ordered by CPUC Decision 07-09-004 in Phase 2 of PG&E's 2007 General Rate Case, which reallocated revenue responsibility among various customer classes.
[2] The results are 7.493 cents per kWh for Method 1 and 7.562 per kWh for Method 2.

What does this mean for customers in the communities that SJVPA plans to serve? PG&E has applied the expected January 1, 2008 rates described above to customer accounts located in the cities and county that SJVPA presently plans to serve.[3] The average generation rate for the

SJVPA area was calculated to be 7.3 cents per kWh (i.e., slightly less than the system-average rate). This needs to be adjusted by the Power Charge Indifference Amount (PCIA), a non-bypassable charge that is not currently shown as a separate charge on PG&E's tariffs but rather is bundled in with the generation rate. Since CCA customers will owe the PCIA (or will benefit from the PCIA if it is negative), it must be netted against the 7.3 cents per kWh generation rate to determine the "shopping credit" -- i.e., the rate level that SJVPA must beat if CCA customers are to achieve savings. Since the PCIA is expected to be a negative 0.4 cents per kWh on January 1, 2008, the shopping credit is estimated to be 7.7 cents per kWh (7.3 cents minus negative 0.4 cents). Note that this is equal to SJVPA's proposed generation rates shown in Table 29 of SJVPA's August 2007 revised CCA Implementation Plan and Statement of Intent.

However, the final "shopping credit" for 2008 for customers to be served by SJVPA is likely to be lower than 7.7 cents per kWh for two reasons. The first is due to the aforementioned expected reduction of approximately 0.16 cents per kWh in March 2008. The second is because PG&E's generation rate includes some generation costs that the CPUC may soon deem to be non-bypassable (as noted in my September 21, 2007 letter, and in my October 25, 2007 comments on SJVPA's revised August 2007 Implementation Plan). In a series of decisions, the CPUC has already determined that any above-market costs associated with PG&E's "new world" generation costs are the responsibility of all customers, including CCA customers.[4] While the CPUC has not yet issued its decision, we anticipate that the new world procurement costs are above market, and may further reduce the "shopping credit" for SJVPA customers.

We will continue to keep you informed as forecasts are updated and the CPUC issues decisions regarding PG&E's generation rates. In the meantime, we would be happy to answer questions you may have about these issues.

Sincerely,

David E Rubin

Attachment

[3] The generation rates were applied to customer billing determinants from calendar year 2006. Included in the analysis were the cities of Clovis, Corcoran, Dinuba, Hanford, Kerman, Kingsburg, Lemoore, Parlier, Reedley, Sanger, and Selma, as well as unincorporated areas of Kings County. PG&E's analysis excluded standby, multi-family residential, and street lighting accounts, given their relatively small amounts. This exclusion is not expected to result in a material change in the estimate.

[4] For PG&E, these are costs associated with procurement obligations entered into after January 1, 2004. See CPUC Decisions 04-12-048, 06-07-029, and 07-09-044. The methodology for calculating these "new world" non-bypassable charges is currently being litigated in Track 3 of Phase 2 of CPUC Rulemaking 06-02-013. Briefing just concluded and a proposed decision from the CPUC is expected soon.

Pacific Gas and Electric Company

David E. Rubin
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January 23, 2008

SJVPA Board Member:

The purpose of this letter is to continue to keep you informed of matters that may affect PG&E's generation rates.

On December 7, 2007, the California Department of Water Resources (DWR) terminated an electric power contract with Calpine Energy Services, L.P. ("Calpine 2" contract) effective January 1, 2008. The effect of this cancellation will be to reduce the amount of power that PG&E's customers receive from DWR and concurrently increase PG&E's purchases from other sources ("ERRA" power purchases). As a result, two components of PG&E's generation rate will move in opposite directions: DWR power costs will decrease and ERRA costs will increase.

In order to reflect the above changes in PG&E's generation rates, we have made two recent filings with the CPUC. On January 18, 2008, we requested that PG&E's DWR charges be reduced by the entire amount of the fixed costs which DWR will avoid by the Calpine 2 termination. Today, we asked the CPUC to increase our ERRA charges to reflect an increase in our expected ERRA costs caused by the Calpine 2 termination.

While the exact amount of the net change is not possible to calculate precisely at this time (since the DWR has not yet submitted its revised 2008 charges to the CPUC), we believe that the impact on PG&E's generation rates will be minimal if these changes are implemented contemporaneously (as we have requested).

I will continue to keep you informed as the above proceedings are resolved. In the meantime, please feel free to contact me if you have any questions.

Sincerely,

David Rubin /lu

cc: David Orth

From: Koontz, Shannon M
Sent: Monday, February 11, 2008 1:54 PM
Cc: 'jmulligan@ci.sanger.ca.us'; 'bnakamura@reedley.com'; 'commdev@parlier.ca.us'; 'dfpauley@cityofkingsburg-ca.gov'; 'rocky.rogers@reedley.com'; 'jrousseau@co.tulare.ca.us'; 'lspikes@co.kings.ca.us'; 'etodd@dinuba.ca.gov'; 'JudyB@cityofselma.com'; 'jbriltz@lemoore.com'; 'robertf@ci.clovis.ca.us'; 'lgregory@co.tulare.ca.us'; 'thaglund@ci.hanford.ca.us'; 'dbh@cityofselma.com'; 'rhoggard@co.kings.ca.us'; 'rmanfredi@cityofkerman.org'; 'citymanager@parlier.ca.us'; 'DMeinert@dinuba.ca.gov'; 'kathym@ci.clovis.ca.us'; 'dfpauley@cityofkingsburg-ca.gov'; 'rocky.rogers@reedley.com'; 'jrousseau@co.tulare.ca.us'; 'gmisenhimer@ci.hanford.ca.us'; 'djensen@cityofkingsburg-ca.gov'; 'dwest@co.kings.ca.us'; 'jwhite@ci.sanger.ca.us'
Subject: PG&E Letter to SJVPA

Attached are two documents: a January 23, 2008 letter from PG&E's David Rubin to SJVPA Board members; and an informational notice to be included in PG&E customer bills that has been reviewed and approved by the California Public Utilities Commission (CPUC). The letter and CPUC-approved bill notice describe two recent PG&E submittals to the CPUC regarding proposed changes to PG&E's generation rates. These documents explain that:

- PG&E's January 18, 2008 filing would decrease the Department of Water Resources (DWR) component of PG&E's generation costs; and
- At the same time, PG&E's January 23, 2008 filing would increase the procurement (ERRA) component of PG&E's generation costs.

As described, PG&E believes that the impact on its generation rates will be minimal (and likely negative), if the Commission contemporaneously implements the changes that PG&E has proposed. Comments submitted on PG&E's proposal late last week concurred with this request.

At SJVPA's January 24 Board meeting, the main focus was on the proposed ***increase*** resulting from PG&E's January 23 filing, with no detailed discussion of either PG&E's January 18 filing or Mr. Rubin's letter (the latter of which was contained in the Board packet), both of which described the offsetting **decrease** in PG&E's DWR-related costs. Only after a Board member raised a question was the possibility of an offsetting decrease acknowledged. We understand Board members are interested in the overall effects of PG&E's rate changes, including the decreasing DWR costs that would offset the requested ERRA increase.

We'd like to reiterate the point made in Mr. Rubin's letter and the CPUC-approved bill notice: If these changes are made contemporaneously, as PG&E has requested of the Commission, the impact on our generation rates is expected to be minimal. In fact, as described in the CPUC-approved bill notice, the $531 million ERRA increase would be more than offset by PG&E's requested reductions in DWR-related and other generation-related costs, leaving rates slightly lower by $45 million.

Please feel free to contact us if you have any questions or would like to discuss this matter further.

Cc: SJVPA Board Members

calpineltr.doc (44 KB) Bill Insert.pdf (158 KB)

Redacted

Redacted

Redacted

Pacific Gas and Electric Company

January 23, 2008

SJVPA Board Member:

The purpose of this letter is to continue to keep you informed of matters that may affect PG&E's generation rates.

On December 7, 2007, the California Department of Water Resources (DWR) terminated an electric power contract with Calpine Energy Services, L.P. ("Calpine 2" contract) effective January 1, 2008. The effect of this cancellation will be to reduce the amount of power that PG&E's customers receive from DWR and concurrently increase PG&E's purchases from other sources ("ERRA" power purchases). As a result, two components of PG&E's generation rate will move in opposite directions: DWR power costs will decrease and ERRA costs will increase.

In order to reflect the above changes in PG&E's generation rates, we have made two recent filings with the CPUC. On January 18, 2008, we requested that PG&E's DWR charges be reduced by the entire amount of the fixed costs which DWR will avoid by the Calpine 2 termination. Today, we asked the CPUC to increase our ERRA charges to reflect an increase in our expected ERRA costs caused by the Calpine 2 termination.

While the exact amount of the net change is not possible to calculate precisely at this time (since the DWR has not yet submitted its revised 2008 charges to the CPUC), we believe that the impact on PG&E's generation rates will be minimal if these changes are implemented contemporaneously (as we have requested).

I will continue to keep you informed as the above proceedings are resolved. In the meantime, please feel free to contact me if you have any questions.

Sincerely,

David Rubin

NOTIFICATION OF APPLICATION BY PG&E TO INCREASE ELECTRIC RATES TO RECOVER INCREASED PROCUREMENT COSTS APPLICATION 08-01-014, FILED JANUARY 23, 2008

Each year, Pacific Gas and Electric Company (PG&E) is required to forecast how much it will spend the following year to ensure adequate electricity supplies for its customers. This forecast is reviewed and approved by the California Public Utilities Commission (CPUC). Under California law, if PG&E's power procurement costs (that is, the costs of purchasing electricity for PG&E's customers) exceed the CPUC-authorized revenues by 5% or more, PG&E must file an application for expedited recovery of such costs. PG&E recovers these costs dollar-for-dollar through rates charged to customers, with no profit margin.

On January 23, 2008, PG&E filed Application A.08-01-014 forecasting that its power procurement costs will exceed its CPUC-authorized revenues by more than 5% at the end of March 2008, and that its power procurement costs in 2008 will be $531 million higher than previously forecasted. **This increase in procurement costs is due to the Department of Water Resources' (DWR) recent termination and replacement of its so-called Calpine 2 power contract, which was expected to have provided PG&E's customers with 1000 megawatts (MW) of power in 2008, and PG&E's need to procure additional sources of electricity to replace the Calpine 2 power.**

Does this mean electricity will cost me more?

PG&E's request in this proceeding will increase rates, but PG&E has proposed rate reductions in related CPUC proceedings that, if adopted, would offset the requested rate increase.

To collect the $531 million in higher costs by the end of 2008, A.08-01-014 requests an overall electric rate increase of 6.8% to go into effect with usage beginning May 1, 2008. The rate changes by customer class for bundled customers and direct access customers associated solely with A.08-01-014 are provided in the second and third columns of the table below. The final two columns of the table show the rate impact of A.08-01-014 combined with the effects of the cost decreases proposed by PG&E in the other proceedings (described on reverse side). "Bundled customers" means customers who receive electric generation as well as transmission and distribution services from PG&E. "Direct access" customers are customers who purchase energy from a supplier other than PG&E but still get transmission and/or distribution services from PG&E.

Pacific Gas and Electric Company Illustrative Revenue Increase
(Dollars in Thousands)

Customer Class	Proposed Revenue Increase	Percentage Change	Proposed Revenue Change with Offsets from Other Proceedings	Percentage Change with Offsets from Other Proceedings
Bundled Service				
Residential	$293,622	6.3%	-$17,945	-0.4%
Small Commercial	$84,923	6.0%	-$5,190	-0.4%
Medium Commercial	$136,521	7.4%	-$8,344	-0.4%
Large Commercial	$80,421	7.8%	-$4,915	-0.5%
Streetlights	$3,464	5.4%	-$212	-0.3%
Standby	$1,864	6.6%	-$114	-0.4%
Agriculture	$33,833	6.0%	-$2,068	-0.4%
Industrial	$100,045	8.7%	-$6,114	-0.5%
Total Bundled Change	**$734,692**	**6.8%**	**-$44,901**	**-0.4%**
Direct Access Service				
Residential	$6	0.2%	-$1	0.0%
Small Commercial	$	0.0%	$	0.0%
Medium Commercial	$	0.0%	$	0.0%
Large Commercial	$	0.0%	$	0.0%
Agriculture	$	0.0%	$	0.0%
Industrial	$	0.0%	$	0.0%
Total Direct Access Change	**$6**	**0.0%**	**-$1**	**0.0%**

As noted on other side of this insert, PG&E has proposed rate reductions in other CPUC proceedings that, if adopted, would offset the rate increase requested in A.08-01-014. PG&E anticipates that it will receive a reduction in costs as part of DWR's 2008 revenue requirement proceeding, and PG&E has proposed in a related proceeding that it receive a further reduction in costs to compensate PG&E's customers for the power lost by the Calpine 2 termination. In addition, PG&E expects a decrease in the pending 2008 power procurement cost forecast case. All together, PG&E has proposed that the $531 million requested in A.08-01-014 be offset by an even larger reduction in costs in other CPUC proceedings, for the net overall decrease of $45 million shown in the fourth column of the table.

If the CPUC approves A.08-01-014, without any of the offsetting decreases proposed in the other proceedings described above, the bill for a typical bundled customer using 550 kWh per month would increase $1.51 from $72.28 to $73.79. The bill for a typical bundled customer using approximately twice the average baseline allowance, or 850 kWh per month, would increase $10.94 from $147.49 to $158.43 per month.

PG&E has requested that the rate changes associated with A.08-01-014 be consolidated with changes in other CPUC proceedings and incorporated into rates on or after May 1, 2008, so the eventual net change in rates for individual customers is difficult to predict.

Detailed Information About PG&E's Application

Due to DWR's termination of the Calpine 2 contract, PG&E forecasts that its power procurement costs will exceed revenues by more than 4% by the end of January 2008 and by more than 5% by the end of March 2008. PG&E also forecasts that its power procurement costs in 2008 will be $531 million higher than forecasted prior to DWR's Calpine 2 termination unless immediate rate relief is approved. PG&E requests that it be permitted to recover this increase in costs over the 8 months remaining in 2008, assuming a May 1 implementation date for new rates. PG&E asks that a decision approving its application be issued by April 10, 2008.

THE CPUC PROCESS

The CPUC's independent Division of Ratepayer Advocates (DRA) will review this application, analyze the proposal, and present an independent analysis and recommendations for the CPUC's consideration. Other parties of record will also participate.

The CPUC may hold evidentiary hearings where parties of record present their proposals in testimony and are subject to cross-examination before an Administrative Law Judge (ALJ). These hearings are open to the public, but only those who are parties of record are allowed to present evidence or cross-examine witnesses during evidentiary hearings.

After considering all proposals and evidence presented during the hearing process, the ALJ will issue a draft decision. When the CPUC acts on this application, it may adopt all or part of PG&E's request, amend or modify it, or deny the application. The CPUC's final decision may be different from PG&E's proposed application filing.

FOR FURTHER INFORMATION

For more details call PG&E at **1-800-PGE-5000** • Para más detalles llame **1-800-660-6789**
詳情請致電 **1-800-893-9555** • For TDD/TTY(speech-hearing impaired) call **1-800-652-4712**

You may also contact the CPUC's Public Advisor with comments or questions as follows:

Public Advisor's Office	**1-415-703-2074** or **1-866-849-8390** (toll free)
505 Van Ness Avenue, Room 2103	TTY **1-415-703-5282**, TTY **1-866-836-7825** (toll free)
San Francisco, CA 94102	E-mail to **public.advisor@cpuc.ca.gov**

If you are writing a letter to the Public Advisor's Office, please refer to A.08-01-014. All comments will be circulated to the Commissioners, the assigned ALJ and the CPUC's Energy Division staff.

Reviewed by the California Public Utilities Commission

Printed with soy ink

PG&E **Pacific Gas and Electric Company®**

3.08

Appendix 3

Detailed Comparison Between PG&E's and BP's Assumptions

Row		Marin BP	Global Energy	Notes
Row	**General Assumption**			
1	Program Operations Commence	1/1/2010	1/1/2011	
2	Full Program Implementation	1/1/2011	1/1/2011	
3	Peak Load (2011)	237 MW	237 MW	
4	Annual Load (2011)	1,308 GWh	1,308 GWh	
5	Approx. Accounts at Full Implementation (2011)	111,000	N/A	Number of accounts not needed to calculate supply costs.
6	Renewable Energy Supply (as a % of total) - 2010	56.00%	N/A	First year of Global's analysis is 2011.
7	Renewable Energy Supply (as a % of total) - 2011	70.00%	70.00%	
8	Renewable Energy Supply (as a % of total) - 2014	81.00%	~81.00%	
9	Distribution Losses	7.00%	7.00%	
10				
11	**Marin County CC Full Requirements Cost 2011-2013**			
12	Full Requirements Electric Supply ($/KWh) 2011-2013	$0.088	$0.118	Global's estimate includes all resource capital, fuel, variable O&M, and Other System costs needed to meet Marin CCA demand during 2011-2013
13				
14	**Capacity**			
15	Reserve Margin	15.00%	15.00%	
16	Total Renewable Capacity Developed by CCA	200	200	
17	Wind Capacity	150	150	
18	Biomass Capacity	50	50	
19	Wind Capacity (CF)	35.00%	23.00%	23% CF reflects assumption that CA Class 5 Wind is unattainable.
20	Biomass Capacity (CF)	80.00%	78.00%	Global modeled biomass with 78% CF as depicted in Marin CCA report.
21	$/MWh Cost - Wind	$85-105	$127.00	Cost range from p.55 of the BP; Global assumed installed cost of $2,357/kW (2007$)
22	$/MWh Cost - Biomass	$65-80	$96	Cost range from p.55 of the BP; Global assumed biomass cost at CPUC's MPR - a competitive market rate.
23	Installed Cost - Wind ($/kW)	$2,000	Refer to Row 21	These costs are included in Global Energy's estimate above.
24	Installed Cost - Biomass ($/kW)	$2,500	Refer to Row 22	These costs are included in Global Energy's estimate above.
25	Fixed O&M - Wind ($/kW-yr)	$11.50	Refer to Row 21	These costs are included in Global Energy's estimate above.
26	Fixed O&M - Biomass ($/kW-yr)	$70.00	Refer to Row 22	These costs are included in Global Energy's estimate above.
27	Variable O&M - Wind ($/MWh)	$5.50	Refer to Row 21	These costs are included in Global Energy's estimate above.
28	Variable O&M - Biomass ($/MWh)	$5.00	Refer to Row 22	These costs are included in Global Energy's estimate above.
29	Fuel - Biomass ($/MWh)	$25.00	Refer to Row 22	These costs are included in Global Energy's estimate above.
30	Integration Cost - Wind ($/MWh)	$25.00	Refer to Row 21	These costs are included in Global Energy's estimate above.
31	Cost of Money (Rate)	5.50%	4.35%	Global Energy used muni financing interest rate from CEC's Cost of Generation model.
32	Financing Term	30 Years	20 Years	Global Energy uses same 20-year period as CEC's Cost of Generation model.
33	Renewable Capacity Online Date	1/1/2014	1/1/2014	
34				
35	**Operating Costs**			
36	Operations and Scheduling Coordination ($/KWh)	$0.005	$0.005	
37	Annual Escalation (Ops & SC)	3.00%	0.00%	
38	Billing and Collections ($/KWh)	$0.001	$0.001	
39	Annual Escalation (B&C)	3.00%	2.50%	
40	Non-Renewable Resource Post-2011 Costs (GT and CC) ($/KWh)	NA	$0.061	Marin BP's cost assumptions for non-renewable resources (i.e. CC and GT) could not be determined.
41	CAISO Charges ($/KWh)	$0.003	$0.001	
42	Distribution Losses	$0.005	Included above	
43	Resource Adequacy ($/KWh)	$0.004	Included above	
44	Green Premium ($/KWh)	$0.015	Included above	
45				
46	**Customer Load and Rates**			
47	Annual Load Growth	0.50%	<0.50%	
48	Annual Rate Escalation (CCA)	3.50%	2.50%	
49	Annual Rate Escalation (PG&E)	3.50%		Global Energy modeled Marin CCA's costs.