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**Review of PG&E's March 5, 2008 Comments on the  
Business Plan for the Marin County Community  
Choice Aggregation Program**

**William B. Marcus**  
**JBS Energy, Inc.**  
311 D Street  
West Sacramento  
California, USA 95605  
tel. 916.372.0534

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## **I. Introduction**

JBS Energy, Inc. was asked to provide comments on Pacific Gas and Electric Company's "Comments on the January 2008 Marin CCA Business Plan" (transmitted to the County by letter dated March 5, 2008). This review provides specific comments on many assertions in the PG&E March 5<sup>th</sup> comments that, if accurate, would have a significant impact on the analysis presented in the Marin CCA business plan.

JBS Energy previously provided an independent review of the business plan to verify the soundness of the assumptions and analysis, and examine the risks to Marin communities under a CCA or the status quo. In that review, the assumptions and analysis were found overall to be sound and generally conservative.

With respect to PG&E's March 5<sup>th</sup> comments on the business plan, significant portions of PG&E's analysis do not hold up under scrutiny.

1. PG&E did not include transparent assumptions when forecasting its own generation costs,
2. PG&E's analyzed its historical generation cost escalation based on a 1998 starting point. Conditions in 1998 are clearly unrepresentative and lead to a low estimate of cost escalation that will not recur in the future;
3. PG&E used an improbable gas forecast that assumes gas will be 14% cheaper in about 12 years than it is now.
4. PG&E made assumptions for costs of renewable generation acquired by the Marin CCA and GHG reduction from the Marin CCA that conflict with other assertions either elsewhere within PG&E's comments or in other recent reports to which PG&E was a party.

As stated in its earlier independent review of the Marin business plan, JBS Energy found that the plan provides a reasonable basis for going forward. PG&E's analysis is flawed, and as a result, does not provide evidence to the contrary.

## II. Costs of PG&E Versus CCA Service

### A. *PG&E's Forecast of Its Own Generation Costs*

#### 1. **Lack of Transparency of PG&E's Forecast**

First, it is extremely interesting that PG&E prepared a detailed pro forma of what it alleges that the Marin Clean Energy CCA would cost, while only presenting summary numbers as to the cost of its own generation resources. We do not even know if they are computed on the same basis as the Marin County numbers (e.g., whether PG&E used the same high cost and low capacity factor for their wind turbines as Marin's, how PG&E proposes to achieve renewable compliance, or any information on the costs of either its existing or new generation). In essence, PG&E is largely asking Marin to accept a black box regarding its own future costs while providing a detailed critique of Marin's alleged future costs.

#### 2. **PG&E's Gas Forecast**

Large portions of PG&E's costs are based on gas prices either directly (for new gas-fired units PG&E is either owning or purchasing under tolling agreements), or indirectly (through gas indexed prices for Qualifying Facilities and spot and short-term firm market prices that generally fluctuate with gas prices). If gas prices increase, PG&E's costs increase significantly. The CCA's costs increase by a much lower lower percentage when gas costs rise because its costs (dominated by the high renewable content) have less sensitivity to gas. As a result, a low gas price forecast makes the CCA look worse relative to PG&E.

PG&E generation pro forma for Marin is based on a gas price scenario, even though PG&E has not divulged the gas price forecast it used to project its own costs).. Therefore it is instructive to understand PG&E's gas forecast. PG&E's forecast from 2011-2020 (given on page 7 of its report) is compared below to recent (March 6) New York Mercantile Exchange (NYMEX) data for the current 12-month strip (April, 2008 to March, 2009) and to NYMEX futures for 2011-2020. It should be noted as a caveat that NYMEX futures markets are not extremely liquid beyond three or four years from the present. A further caveat is that an open futures contract requires collateral which creates

an opportunity cost in foregone interest, so that the futures price quoted below may actually be slightly less than 100% of the expected cost of gas in the future.

**Comparison of PG&E Gas Prices and Recent NYMEX Futures**

|                        | PG&E    | NYMEX<br>3/6/08 |
|------------------------|---------|-----------------|
| 2008 12<br>month strip |         | \$ 10.19        |
| 2011                   | \$ 8.45 | \$ 9.05         |
| 2012                   | \$ 8.36 | \$ 9.04         |
| 2013                   | \$ 8.07 | \$ 9.09         |
| 2014                   | \$ 7.99 | \$ 9.16         |
| 2015                   | \$ 7.91 | \$ 9.25         |
| 2016                   | \$ 7.82 | \$ 9.35         |
| 2017                   | \$ 8.13 | \$ 9.48         |
| 2018                   | \$ 8.23 | \$ 9.61         |
| 2019                   | \$ 8.47 | \$ 9.76         |
| 2020                   | \$ 8.78 | \$ 9.91         |
| 2021                   | \$ 8.95 |                 |

PG&E’s forecast assumes that gas in 2021 will be 14% cheaper than the *current* 12-month strip price of gas, and that gas prices will be cheaper in every year from 2012-2018 than they are in 2011. Essentially this PG&E forecast means that renewable energy would be less cost-effective relative to gas-fired energy in the future than it is now.

NYMEX futures show a slowly rising gas price from 2011-2020 and average gas prices that are 14% higher than PG&E’s prices over the 2011-2020 decade.

**3. PG&E’s Other Generation Costs**

Other issues that were not delineated in PG&E’s forecast of its own costs but that we have identified previously were:

- (1) Hydroelectric costs (both capital and operating) have been escalating significantly since 2000. O&M costs are up 57% from 2004-2009, while capital expenditures per year have more than doubled from the 2001-2004 time frame to 2007-2009.<sup>1</sup>

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<sup>1</sup> PG&E 2007 TY General Rate Case, Exhibit 3, Chapter 4 (Hydro Operations program Costs), Table 3-2, p. 3-63 for O&M costs. PG&E 2007 TY General Rate Case, Exhibit 3, Chapter 4 (Hydro

- (2) Hydroelectric production is likely to decline slowly over time, due to environmental restrictions as projects are relicensed, potential changes due to global climate change, and expiration of cheap hydro-based contracts with irrigation districts over the next 20 years.
- (3) Nuclear O&M costs have been rising; nuclear fuel costs have been increasing rapidly in the last several years; and PG&E is expected to spend over \$1 billion in nuclear capital just between now and 2012.
- (4) Cost of new renewables for PG&E to reach 20% RPS is not clearly stated. If the costs are rising for Marin, as PG&E alleges, then they are also rising for PG&E.
- (5) Cost of new PG&E-built resources and long-term contracts are increasing.
- (6) Cost of Greenhouse Gas compliance (largely included in Marin's costs because of its more extensive use of renewables) will raise PG&E's costs.

PG&E's forecast also does not include other new relatively expensive resources such as new nuclear power plants<sup>2</sup> at costs as high as \$4500/kW<sup>3</sup> that we know are not included in any PG&E generation cost forecasts.

#### **4. PG&E's Historical Generation Rates**

Instead of providing a detailed forecast of its own generation rates, PG&E attacks Navigant's forecast based on past information. PG&E's report claiming instead that "PG&E suspects Marin's consultant, Navigant may have 'cherry picked' its analysis periods to show PG&E historical rates in their worst light."<sup>4</sup> PG&E provides data on the past 10 years allegedly supporting annual generation rate increases of 0.5% to 2.5% (midpoint 1.5%).

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Operations program Costs), Table 3-1, p. 3-62. and PG&E 2003 TY GRC Exhibit 10, Table 3-1, p. 3-54. for capital costs.

<sup>2</sup> David R. Baker, PG&E Looking at Nuclear Plants, San Francisco Chronicle, November 29, 2006. <http://www.sfgate.com/cgi-bin/article.cgi?f=/c/a/2006/11/29/BUGPNMLIAH1.DTL>

<sup>3</sup> Jim Harding, Economics of Nuclear Power and Proliferation Risks in a Carbon Constrained World, Presentation to California Energy Commission Docket 2006-IEP-1, June 28, 2007.

<sup>4</sup> PG&E comments, page 11, footnote 16.

The starting point of PG&E's most recent estimate is 1998. In 1998, PG&E's generation rates included two components that were unusually high that have subsequently been removed. First, PG&E's 1998 generation costs included about \$1 billion in accelerated depreciation and return and associated income taxes paid on the undepreciated portion of Diablo Canyon due to restructuring. Those costs no longer exist. The return and depreciation for the sunk costs at Diablo Canyon declined to about \$160 million in 2001 and beyond. Second, PG&E's generation costs included \$600 million of fixed rate energy from Standard Offer 4 QF contracts. Had those contracts been converted to variable rate energy at that time, they would have been \$400 million cheaper, though by 2000 and beyond their costs would have risen significantly with higher gas prices. There is thus \$850 million to \$1.25 billion of excess costs in the 1998 base year – which amounts to about 1.1 to 1.6 cents/kWh. In essence, if one does an “apples and apples” comparison of PG&E's generation costs today with PG&E's generation costs in 1998 adjusted downward by 1.1 cents to 1.6 cents/kWh to reflect regulatory and contractual changes that will not recur in the future, the growth rate would have been 3.5% to 4.5% per year – at or above the Navigant estimate.

### ***B. PG&E's Forecast of Marin Generation Costs***

PG&E's forecast of Marin County CCA generation costs, by contrast is more detailed, but it also contains a number of problems.

In the pre-2014 environment, PG&E simply develops a resource plan for Marin assuming it will own or pay under long-term contract for combined cycle and combustion turbines.<sup>5</sup> Marin's actual plan is to acquire generation through a full requirements contract and then substitute its own renewables.

PG&E claims that the full requirements contract that Marin is proposing for 2011-2014 (which it calls a placeholder) will actually be extremely expensive. However, PG&E's calculations do not take into account the results of the San Joaquin Valley Power

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<sup>5</sup> Both of these generation technologies use natural gas. Combined cycle generation is a more fuel-efficient technology than combustion turbines, which are generally used for peaking.

Authority's full requirements bid, which locked in a contract price starting at a 5% discount from PG&E's generation escalating at 2% per year, with a portfolio that complies fully with California's Resource Adequacy (RA), Renewable Portfolio Standard (RPS) and Greenhouse Gas (GHG) requirements. PG&E points to the alleged high risk of that bid (page 15), but the recipient of the bid (SJVPA) does not believe that the risk is significant,

While the Marin CCA will not receive such a discount because of the considerably higher renewable content (and never planned on receiving such a discount), this full requirements contract does provide information that PG&E has ignored. Instead, PG&E is assuming that any power purchased by Marin must be paid for under long-term contract prices equal to the full cost of new resources without any benefit from municipal ownership. PG&E has also implicitly assumed (without ever stating it clearly) that power prepayment – which will provide a further benefit to ratepayers of SJVPA – would be unavailable to a Marin CCA.

PG&E's 2011 estimate of the Marin CCA Blended Rate in Table 11 of \$125 per MWh appears very high when one considers that PG&E's estimated cost of buying renewable energy as shown in Table 10 is \$96 per MWh. PG&E's analysis appears to indicate that natural gas generation is more expensive than buying renewable energy. If that is the case, then the Marin CCA would likely buy more renewable energy initially than projected in the business plan.

After 2014, PG&E's analysis has significant questionable aspects:

1. PG&E continues to assume that Marin will buy combined cycle and combustion turbine powerplants under long-term contract as well as owning a large block of renewables.
2. PG&E appears to assume that Marin will not be able to use its municipal financing on biomass plants (or presumably any other generating units except windmills – where PG&E did not directly attack municipal financing except to

claim that opt-out creates risk)<sup>6</sup> because owners of those plants would not want to receive less than the CEC's estimate of the market price. This is unreasonable, because the CCA would be owning and operating the plants, not some other "owners."

3. PG&E claims that publicly owned utilities will not sell power to the Marin CCA at cost because they can get higher market prices. (page 15) It appears that PG&E is confusing spot and short-term markets with longer term project financing. PG&E is also ignoring that tax exemption can be lost under certain conditions if more than 25% of the output of a municipal project is sold to a taxable entity. At the time when a project is being developed, Marin could be contractually assigned a long-term purchase contract at cost for part of a project (developed for example by NCPA or SMUD<sup>7</sup>) to enable these entities to spread the cost and impact of a single project among more participants. This type of contract would be similar to the types of contracts currently used among members of the Southern California Public Power Authority and NCPA.
4. PG&E also assumes that wind power will become much more expensive in cost (\$2,500 per kW installed or \$223/kW-year) and will provide energy at only a 23% capacity factor (a figure which PG&E obtained from its entire fleet of wind turbines – including plants installed in the 1980s that have not been repowered and modernized). These figures are considerably more pessimistic than those PG&E and other industry participants are using to justify construction of new transmission lines. For example, PG&E participated in a 2007 study by the Western Regional Transmission Expansion Partnership examining the benefits and costs of the Frontier Transmission line between California and Wyoming. In

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<sup>6</sup> On the one hand, PG&E claims that financing projects will be difficult because of opt-out provisions; on the other hand, it claims that exit fees (designed to mitigate this financing risk) will be risky to Marin residents. Both of these points cannot be completely true at the same time,

<sup>7</sup> NCPA (Northern California Power Authority) is a JPA that finances, builds and operates generation on behalf of its municipal utility members. A CCA would be qualified to use NCPA services. SMUD (Sacramento Municipal Utility District) has expressed interest in collaborating with CCAs on renewable generation projects.

this report, an average capacity factor of 37% was used as a proxy for all California wind generation, and an installed cost in 2015 of \$2,000/kW was used.<sup>8</sup> A study by the same group to evaluate benefits and costs of PG&E's proposed transmission line to British Columbia used a range of capacity factors from 22% to 37% with 30% as the reference case. The study stated that more modern wind installation turbines are expected to average about 36%. The estimated installed cost for wind in California (2015), including transmission needed to connect wind resource areas to the state high-voltage grid, was \$2,000/kW with a range of \$1,500 to \$2,500.<sup>9</sup> These figures are consistent with Navigant's assumptions, whereas PG&E uses the low range for capacity factor and the high range for installed costs in calculating the cost of Marin's wind resource. The high cost cited by PG&E for LADWP's 120 MW Pine Tree Wind Farm is misleading because it includes the costs of a high voltage transmission line and substation that would be rolled into transmission rates and ultimately be credited back to the generator developer under the FERC/CAISO's<sup>10</sup> generator interconnection rules.

5. PG&E shortened the term over which bonds issued to finance Marin's renewable resources are repaid from the 30 years used in the business plan to 20 years. Shortening the financing term increases the estimated costs of the Marin CCA program during the first 20 years. However, PG&E's analysis is truncated even assuming that debt was only issued for 20 years. It shows allegedly higher costs in earlier years but fails to show that the CCA costs would be significantly reduced for the duration of the renewable plants' useful lives once the bonds are paid off.

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<sup>8</sup> Western Regional Transmission Expansion partnership Economic Analysis Subcommittee, Benefit-Cost Analysis of Frontier Line Possibilities, Final Report, April 27, 2007, Page 15. A PG&E employee is the Chair of the Economic Analysis Subcommittee that produced this report.

<sup>9</sup> Western Regional Transmission Expansion partnership Economic Analysis Subcommittee, Benefit to Cost Ratio Screening Analysis, Final Report, October 23, 2007, Pages 11-12. Four PG&E employees are represented on the Economic Analysis Subcommittee that produced this report.

<sup>10</sup> The Federal Energy Regulatory Commission (FERC) and California Independent System Operator (CAISO) have regulatory jurisdiction over transmission lines.

6. PG&E undervalues the capacity of Marin's wind resource by assuming that it has no resource adequacy value due to the fact that Marin is winter peaking and wind production tends to peak during the summer. PG&E overbuilds the resource portfolio attributable to Marin with natural gas combustion turbines which drives up the cost. PG&E's approach fails to consider that the resource adequacy requirement is a monthly obligation, so the wind resource would meet at least some of Marin's resource adequacy needs. Furthermore, even if Marin did not need all the capacity, as PG&E assumes, Marin could sell any excess resource adequacy capacity to other load serving entities that do have summer peaking profiles. Such sales would generate revenue that PG&E's analysis does not account for.

### *C. Estimates of Greenhouse Gas Emissions Avoided by Marin CCA*

PG&E's critique of the Navigant Report's discussion of greenhouse gas emissions is muddled. PG&E puts forward two different positions on the same page and a third position two pages earlier.

Navigant used a range of 400-707 tons of Carbon dioxide per million kWh (gigawatt-hour or GWh), based on a mix of combined cycle and other resources.

On page 21, PG&E claims that none of Navigant's calculations should include any existing fossil resources with GHG emissions higher than combined cycle gas (so that a maximum figure of 400 tons/GWh should be used), rather than the range.

On page 21, PG&E provides a second calculation. PG&E inconsistently implies that that the Marin GHG profile (nearly all renewable) should really be compared to PG&E's entire portfolio (160-200 tons per million kWh or GWh). But PG&E's portfolio includes large hydro and nuclear plants. We know that PG&E will use its hydro and nuclear plants to serve its remaining customers. It would be absurd to assume that PG&E will spill water at hydro dams or turn down Diablo Canyon just because Marin County sets up a CCA. Therefore, the appropriate comparison is only with the fossil resources that will be displaced by CCA operations.

In fact, PG&E itself made the **correct** comparison two pages earlier in its comments. On page 19 (when discussing the benefits of its energy efficiency programs), PG&E made the correct calculation (14,040 tons of CO<sub>2</sub> for 25 GWh of energy efficiency savings or 561 tons/GWh). This figure reflects only fossil energy and is almost exactly the midpoint between Navigant's low and high assumptions.

### III. Other Risks Identified by PG&E

#### A. *Opt-Out Rates and Exit Fees*

PG&E raises concerns that opt-out rates are too low, particularly for commercial customers, and that exit fees propose great risks.

While opt-out rates are indeed uncertain, there is experience with programs similar to CCAs in Massachusetts and Ohio. Massachusetts experienced an opt-out rate of 1%, while Ohio saw a 3% opt-out rate initially.<sup>11</sup>

PG&E points to a problematic situation in Ohio as a risk for both the CCA and for customers (who would conceivably pay exit fees). "A significant return to utility service, as happened in Ohio when utility rates fell, is a distinct possibility."<sup>12</sup> PG&E cited a paper by Stephen Littlechild in support of this contention.<sup>13</sup> However, PG&E uses Ohio as a scary example while failing to inform the readers of the true complexity of the situation in Ohio. But Dr. Littlechild laid out all of the complexity elsewhere in the document cited by PG&E. He also published another version of this paper as a working

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<sup>11</sup> Brown, Matthew. "An Analysis of Opt-Out Aggregation in Ohio and Massachusetts," September 2002. Prepared for the National Center for Appropriate Technology's National Energy Affordability and Accessibility Project, as cited in Garance Burk, Chris Finn and Andrea Murphy, "Community Choice Aggregation: The Viability of AB 117 and its Role in California's Energy Markets" an analysis for the California Public Utilities Commission, June, 2005.

<sup>12</sup> PG&E comments, page 22, citation omitted in quotation.

<sup>13</sup> 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.

paper at the Kennedy School of Government at Harvard.<sup>14</sup> The paper tells a more complete story than PG&E did. The exodus of customers to the incumbent utility occurred at the transition point of another failed deregulation scheme – not a decline in utility rates due to market forces as PG&E implies. The municipal aggregators in Ohio faced this problem in the aggregation process when a multi-year contract and a multi-year rate freeze ended simultaneously. The incumbent utility offered a new rate stabilization plan in response to political pressure, rather than letting rates go up to even higher market levels. The plan, for First Energy in particular, caused shopping credits for customers to fall while rates went up.<sup>15</sup> The Ohio Consumers Counsel stated that aggregation and competition declined because of regulation, not the market:

This [outcome] is due in large part to the structure of the Rate Stabilization Plans which produce artificial shopping credits<sup>16</sup> that are below the market price and are below the electric utilities' true generation costs. With this reality, competitive retail electric suppliers are reluctant to commit their companies' resources in a state where they are hindered from offering a competitive product. In order for the free market to work, the full generation prices of the utility company need to be avoidable, as was intended by Senate Bill 3, and which has yet to occur.<sup>17</sup>

Dr. Littlechild summed up the situation as follows:

Holding electricity rates below market levels had a predictable effect on retail competition generally as well as on municipal aggregation in particular. Competitive providers could no longer beat or even match the prices set by incumbent utilities. Not only were new competitors deterred from entering the market, existing suppliers were driven to exit.<sup>18</sup>

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<sup>14</sup> Stephen Littlechild, "Municipal Aggregation and Retail Competition in the Ohio Electricity Sector," Paper No. CWPE0739 and .EPRG 0715. August, 2007.  
<http://www.hks.harvard.edu/hepg/Papers/Ohio%20paper%20eprg0715.pdf>.

<sup>15</sup> *Id.*, page 25.

<sup>16</sup> "Shopping credit" is the amount that the incumbent utility credits a customer who purchases electricity from an alternate provider.

<sup>17</sup> *Id.*, page 26

<sup>18</sup> *Id.*, page 22.

This is not the circumstance where California finds itself, so PG&E's extrapolation of a difficult situation from Ohio is of limited applicability.<sup>19</sup> California has already been through a failed deregulation scheme that started with a rate freeze that ended unsustainably due to the market manipulation in the energy crisis. California is still paying for that mistake.

The Marin CCA has a different focus with a heavy focus on ownership of clean energy choices that are not tied to fossil fuels and their volatile prices. It is possible that the percentages of customers who sign up for the CCA might be somewhat lower than experienced in Ohio and Massachusetts (as has been projected in the Business Plan), but it is the intention of the CCA that the customers who do sign up will be given information as to what they will be buying and why they are buying it and would therefore be unlikely to bolt if gas prices decline for a short period of time.

Finally, as noted in JBS Energy's original review of the business plan (page 5), exit fees are a backstop, *not a routine part of system operations*. They would come into play under specific conditions if large amounts of CCA loads shifted at one time to other suppliers. Those conditions could be caused either by major market shifts (rapidly falling gas prices and less emphasis on greenhouse gas emissions) or major regulatory changes (e.g., approval of direct access with a short-term spot market emphasis; or regulatory decisions changing to become more adverse to CCAs after start-up such as requiring CCAs to beat a price below the market price of utility generation – what happened in Ohio). They are more likely to be needed early in the program than later on, when embedded costs of CCA-owned renewable resources are fixed and/or declining.

However, Marin should evaluate the risk of differences opt-out rates, particularly among medium commercial customers, in the sensitivity analyses that is being performed by Navigant. Such a review would determine the extent to which the assumed opt-out rates

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<sup>19</sup> The only way in which California could end up with a similar situation as Ohio is if regulators make decisions that artificially give advantages to incumbent utilities – by setting the price that a CCA must beat (through CCA CRS calculations) based solely on a very short-term spot market price that is below the cost of generation that the utility has built or is planning to build – whether renewable or conventional.

affect the viability and economics of the CCA. While it does not appear likely as a matter of first impression that increases in opt-out rates within a reasonable range would jeopardize CCA economics or viability, the issue should be examined to determine whether this impression is correct.

### ***B. Early JPA Debt***

At page 17, PG&E suggests that Marin County and the member cities of the JPA would be at risk for repayment of the initial \$6.4 million in startup financing identified in the business plan 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. According to the schedule shown in Table 5 of the business plan, this financing would not occur until **after** bids are received from suppliers, so the risk that PG&E paints appears to be a non issue. The JPA agreement and the CCA project agreement (described as Project Agreement No. 1 in the business plan) would define whether members are liable in any way for the debts of the JPA. The San Joaquin Valley JPA agreement, for example, explicitly states that unless otherwise agreed, the debts, liabilities or obligations of the Authority shall not be debts, liabilities or obligations of the Parties (Section 2.3).

### ***C. Rate Design***

PG&E points to some language in the business plan indicating that it might be possible for the CCA to develop a different residential rate design, suggesting that generation rates will ultimately be flat in the residential class. In this area, PG&E is likely to be correct that flat generation rates are likely to be implemented over time. However, this issue has previously been specifically examined by Navigant. The rate design that PG&E is discussing has a small adverse impact (about \$1/MWh) relative to the rate design included in the business plan. Therefore, while changes in rate design may mean that the CCA may not have some flexibility that it might otherwise have had (and which was not factored into any of its business plan results in any event), the issue is simply not important.

#### *D. Pro Forma in Appendix A*

PG&E makes much of the fact that Navigant's pro forma is presented differently for the 2009-2013 period shown in the main body of the business plan and the longer term 2014-2025 shown in Appendix A. Navigant has confirmed that the 2009-2013 pro forma shown in Table 3 shows projected program revenues and costs, whereas the pro forma in Appendix A shows projected program costs relative to costs at PG&E rates. The revenues in Table 3 are net of franchise fees surcharges that would be paid by CCA customers, as these are assumed to be credited back to customers through the CCA's rate design. Franchise fees are shown as a program cost line item in Appendix A. In essence, the two tables were prepared differently for different purposes – with the later pro forma designed to show that the program could compete with PG&E rates in the long run. When making any kind of projection for business plans, it should be recognized (as Navigant has recognized) that extremely detailed projections of operations (e.g., exactly how many administrative staffers would be hired by the program) beyond the first five years are likely to be less reliable. What is important in the long-term pro forma is the relative cost between the two options based on the strategic investment decisions, and that is what Navigant has presented in the business plan.