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Pacific Gas and Electric Company

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MAR 27 2009
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March 26, 2009

Melissa Jones, Executive Director
California Energy Commission
Attn: Docket 09-IEP-1
1516 Ninth Street
Sacramento, CA 95814

DOCKET	
09-IEP-1C	
DATE	MAR 26 2009
RECD.	MAR 27 2009

Re: Docket: 09-IEP-1 – PG&E's data response

Dear Ms. Jones,

The accompanying narrative, compact disks, and paper copies contain PG&E's response to the California Energy Commission's request for information related to PG&E's historical and forecast data regarding electricity demand, supply and associated revenue requirements, as the CEC requested by its forms and instructions adopted in December, 2008, in preparation for the 2009 IEPR. We apologize for the delay in sending this information to you. We know you have a challenging schedule ahead of you in this IEPR, but we wanted to be sure that the version we are sending you reflected updated information and was adequately reviewed

We are also providing applications for confidential designation, for a limited subset of the data in these forms. For ease of review, we have provided two different copies of the paper and electronic data sets – one confidential version and one with the confidential cells blacked out. (We have not included paper copies of Form 1.6; the files are too large.) PG&E requests that the Commission promptly grant this request in order to ensure protection of this confidential, proprietary, and competitive-sensitive trade secret information.

We are providing two different scenarios for investing in future electric resources. Scenario 1 has forecasted RPS resources to meet a 20% minimum RPS target by 2013 and beyond, while Scenario 2 accelerates RPS resource additions more quickly beginning in 2015 to achieve a 33% RPS target by 2020. Although we provide forecasted revenue requirements and sales associated with the two cases, it is worth noting that the resultant projected rates could well be different, because we cannot consider any subsequent real-world events and factors that will change the forecast.

Please also note that, as a general matter, the forward looking information contained in this response is preliminary in nature, given that future events and regulatory decisions that have not been taken into account are likely to occur and these events and decisions may significantly affect the information in this response. Thus, PG&E does not purport that the information contained in this response will reflect actual future rates, revenue requirements, or sales.

PG&E has developed this information after discussing the data requirements with Commission staff. We value the cooperative working relationship we have with your analysts, and encourage you to call me at the number above, or Kathy Treleven at (415) 973-4185, with any questions or concerns you might have.

Sincerely,

Mark Krausse

APPLICATION FOR CONFIDENTIAL DESIGNATION
(20 CCR SECTION 2025)

2009 INTEGRATED ENERGY POLICY REPORT
Docket Number 09-IEP-1C

Applicant: Pacific Gas and Electric Company ("PG&E")

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1. **(a) Title, data, and description of the record.**

Electric Demand Forecast forms issued by the California Energy Commission (CEC) for the 2009 Integrated Energy Policy Report, excluding Form 8 (revenue requirement data), separately provided.

(b) Specify the part(s) of the record for which you request confidential designation.

PG&E is requesting confidential designation for three years for the contents of certain data cells in the Electric Demand Forecast Forms 1.1, 1.2, 1.6(a) and 1.6(b), related to near-term forecasted loads, as described in more detail below.[1]

2. **State and justify the length of time the Commission should keep the record confidential.**

PG&E requests that certain data cells in the demand forecast data in Forms 1.1, 1.2, 1.6(a) and 1.6(b) be designated as confidential. PG&E requests that confidential designation of this information herein be maintained for three years. PG&E believes that this is the length of time that is required to ensure that recent near-term forecasts do not reveal PG&E's ongoing and future procurement and competitive positions and strategies, thereby compromising PG&E's ability to secure the most favorable deals for customers and protect its business strategies and proprietary business planning information from disclosure to competitors.

[1] In addition, Form 2.2 contains economic forecasting information from a private consulting company that is proprietary and therefore may not be shared with third parties other than regulators without the permission of the consulting company.

This competitive and market sensitive information should remain confidential for the near term, because of the knowledge it could impart about PG&E's future procurement needs and patterns, competitive position and business plans.

Specifically for Form 1.1, the following categories for the forecast years 2009-2011:

- Residential;
- Commercial;
- Industrial;
- Agricultural;
- Street-Lighting;
- Other (Incl. Railroad);
- Direct Access Plus Other Non-Utility Procurement**; and
- Total.

Specifically for Form 1.2, the following categories for the forecast years 2009-2011:

- Sales To Bundled Customers (from 1.1);
- Direct Access Plus Other Non-Utility Procurement;
- Total Sales;
- Losses;
- Total Distribution System Energy Requirements; and
- Forecast Net of Uncommitted Impacts (Unmitigated for EE Impacts)*.

Specifically for Form 1.6(a), the following categories for all hours for the forecast year 2010:

- Bundled Load;
- Bundled Losses;
- Unbundled Load (DA + BART);
- Unbundled Losses; and
- Total System Load.

Specifically for Form 1.6(b), the following categories for all hours for the forecast year 2010:

- NP_15; and
- ZP_26.

3. **(a) State the provision(s) of the Public Records Act or other law that allows the Commission to keep the record confidential, and explain why the provision(s) applies to the record.**

Near term forecasted data contained in Forms 1.1, 1.2, 1.6(a) and 1.6(b) provide competitively and commercially sensitive business and resource planning information and trade secrets. Under the Public Records Act, Govt. Code Section 6254(k), records subject to the privileges established in the Evidence Code are not required to be disclosed. See also Govt. Code Section 6254.7(d). Evidence Code

Section 1060 provides a privilege for trade secrets, which is defined in Civil Code Section 3426.1. That definition includes information, including a formula, technique, and process, that derives independent economic value from not being generally known to the public or to other persons who could obtain value from its disclosure.

There are basically two grounds on which to justify confidential treatment of the electric demand forecasts. First, these forms contain annual or hourly demand forecast information that relatively easily allows a party to calculate PG&E's current energy supply needs on a disaggregated (monthly and hourly, bundled and direct access, and/or weather-adjusted) basis. Additionally, a marketer could use the bundled retail sales from Form 1.1 and the hourly data from Form 1.6(a) to create monthly estimates of PG&E's bundled sales if the data were not confidential. Monthly forecast information would help to reveal seasonal trends in PG&E's procurement needs and potentially, the magnitude of market purchases. Thus, given this information, a marketer could affect market prices either by additional buying or aggressive selling. By thus calculating, directly or indirectly, PG&E's "residual net short" position, potential suppliers achieve a competitive advantage that potentially harms PG&E's customers who may end up paying higher power prices.[2] Second, to release this information publicly would allow market participants to have access to competitively sensitive information that would normally not be available to them in this form or format. As a matter of law and public policy, the CEC should ensure that it does not facilitate availability of such data.

The protection of this forecast information is consistent with the CEC's prior decisions on confidentiality in the 2007 IEPR, as well as the CEC's policies regarding the utilities' resource planning information, which generally provide protection for near-term forecast information for three years, while providing for release of such information on an aggregated basis beyond three years. See, e.g., Letters, CEC Executive Director to PG&E, March 12, 2007 and June 19, 2007, Docket No. 06-IEP-1; "Commission Order Denying Appeals of SDG&E, SCE, and PG&E of the Executive Director's Notice of Intent to Release Aggregated Data," September 7, 2005, Docket 04-IEP-1D, California Energy Commission.

(b) Discuss the public interest in nondisclosure of the record. If the record contains trade secrets or its disclosure would otherwise cause loss of a competitive advantage, please also state how it would be lost, the value of the information to the Applicant, and the ease or difficulty with which the information could be legitimately acquired or duplicated by others.

The public and PG&E's customers have a compelling interest in protecting this information from disclosure to competitors or electricity suppliers who could use

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[2] "Residual net short" refers to the amount of energy PG&E needs to procure in the market after meeting its forecasted load with must-take power and utility retained generation.

the information to manipulate the costs of energy supplies procured by PG&E on behalf of its customers. Because of the ease with which PG&E's net short position can be derived using this hourly or annual peak load data, protection from disclosure to third parties is required. These determinations need not be mathematically exact to cause harm; customers incur substantial risk of higher energy prices (or lower revenues from sales) any time a potential supplier knows that a utility must buy or sell gas or electricity on behalf of its customers at any given time. PG&E believes that it would be relatively easy to perform these calculations if the near-term forecast data in Forms 1.1, 1.2, 1.6(a) or 1.6(b) were disclosed.

In general, PG&E's electricity procurement-related and resource planning forecasts created after January 1, 2003 when the utilities resumed their procurement responsibilities are a prime candidate for confidential treatment because such information could be used to reveal sensitive PG&E-specific data on the net short, spot purchases, spot sales, total bundled sales, and contract purchases. Similarly, if buyers know when PG&E must sell power, PG&E could realize a lower price than it would have been able to obtain if the market assumed PG&E had discretion over whether or not to sell. Such market knowledge is a key reason, for example, for why prices drop during spring hydro run-off periods.

The more detail that is made public concerning a utility's relative annual or hourly peak demand positions, the greater the potential for price volatility and market abuse. Suppliers could calculate adjustments to a utility's resource portfolio and be able to determine more accurately the utility's incremental needs from the market. Suppliers might then inadvertently bid up prices either through additional buying or less aggressive selling, in anticipation of significant purchases by the utility, as compared with prior periods.

Also as noted above, the public interest is served by energy agencies protecting the integrity of energy and capacity markets and information. Moreover, because the information on these forms is preliminary, subject to change, and likely to be inaccurate because of ongoing regulatory proceedings and market developments affecting PG&E's electric and gas rates, the CEC should avoid disclosure of the information to parties, especially customers, who might inappropriately use the information for an unintended use and potentially incur harm as a result.

PG&E recognizes that in the 2005 Integrated Energy Policy Report (IEPR) proceeding, in the case of Forms 1.1 and 1.2, PG&E did not previously seek confidential treatment for such data. Since that time, however, the CPUC, the agency charged with the protection of energy utility customers, has issued Decision 06-06-066, in which the CPUC has determined that, in most cases, an investor-owned utility (IOU) may keep confidential the first three years of a demand forecast. (See Appendix 1 of D.06-06-066, category V.) Since the CPUC issued that decision, PG&E has been scrupulous in adhering to the CPUC's confidentiality rules.

4. **State whether the record may be disclosed if it is aggregated with other information or masked to conceal certain portions (including but not limited to the identity of the Applicant). State the degree of aggregation or masking required. If the data cannot be disclosed even if it is aggregated or masked, explain why.**

As explained above, in PG&E's case the near-term forecast data within Form 1.1, 1.2, 1.6(a) and 1.6(b) could allow a party to calculate hourly or annual peak demand and procurement data on a disaggregated basis. Therefore, the peak load forecast data requested herein must not be disclosed to the public or third parties even on an aggregated basis. However, aggregation of data collected by the CEC from all California electric and gas utilities on a statewide basis would be acceptable, as long as not disaggregated by geographic region or service territory in a manner that would permit imputation on a stand-alone utility basis. Also, after the passage of at least three years, release of the data provided herein would not cause as much concern.

5. **State how the record is kept confidential by the Applicant and whether it has ever been disclosed to a person other than an employee of the Applicant. If it has, explain the circumstances under which disclosure occurred.**

As explained above, PG&E maintains access to the above-referenced information in Forms 1.1, 1.2, 1.6(a) and 1.6(b) on a confidential basis. It is only available by hard copy and electronically on a limited basis within certain departments and corporate affiliates, such as PG&E's parent company, that must have access to the information to conduct their procurement, regulatory, and business planning and forecasting activities. In addition, under Standard of Conduct #2 adopted by the CPUC for the utilities' electric procurement activities, PG&E employees are obligated to protect the Company's trade secrets:

> 2. Each utility must adopt, actively monitor, and enforce compliance with a comprehensive code of conduct for all employees engaged in the procurement process that: 1) identifies trade secrets and other confidential information; 2) specifies procedures for ensuring that such information retains its trade secret and/or confidential status [e.g., limiting access to such information to individuals with a need to know, limiting locations at which such information may be accessed, etc.]; ... (See D.02-12-074, pp. 57-58.)

Except as explained above relating to the 2005 IEPR, PG&E has not to the best of its knowledge previously released this information to the general public or to third parties or market participants on an unlimited basis in this format or projecting out over this duration of time. While certain of the information here or similar categories of information may have been provided in part previously under protective order or nondisclosure agreements in various state or federal regulatory filings, PG&E has not to the best of its knowledge previously publicly collated this data into this format.

For all these reasons, PG&E requests that the CEC comply with its obligation under California law to protect this information from disclosure to the public, PG&E's suppliers, or PG&E's competitors.

I certify under penalty of perjury that the information contained in this application for confidential designation is true, correct, and complete to the best of my knowledge and that I am authorized to make the application and certification on behalf of the Applicant.

Dated: March 26, 2009

Signed: Christopher J. Warner

Name: Christopher J. Warner
Title: Chief Counsel
Pacific Gas and Electric Company

Notes of Pacific Gas and Electric Company for Demand, Price and Supply Forms Submittal For the California Energy Commission March 26, 2009 Docket 09-IEP-1

Demand and Price Forms

Form 1. Historic and Forecast Electricity Demand

Form 1.1 Retail Sales of Electricity by Class or Sector (Gwh)

PG&E is providing the requested market sector data in the historic period through 2008 with the exception of direct access information which PG&E does not have prior to 2000. Importantly, PG&E is presenting its “analytic” sales totals (adjusted totals used for modeling purposes), and because direct access amounts are not broken out by class in a like manner, bundled sales cannot be shown by customer class. Therefore, only total retail sales (bundled + DA) are shown by customer class, along with aggregate direct access sales. Columns I and J (electric vehicles and DA loads) are already embedded in the customer class data and are therefore not included in column K total.

In the forecast period PG&E has included the effects of the stated targets of customer energy efficiency programs described in D.04-09-060 (2009-2011) and D.08-07-047 (2012-2020) as reasonably expected to occur, although these targets are regarded as uncommitted. PG&E has also included the impacts the California Solar Initiative as well as customer self-generation programs consistent with those developed for the 2006 Long Term Procurement Plan (2006 LTPP). PG&E uses a regression model to produce its forecast sales and loads and therefore, for the purpose of this submittal PG&E has assumed that direct access remains constant throughout the forecast horizon at its current levels (except for decreases each year due to increasing customer energy efficiency).

PG&E is requesting confidential treatment for various portions of Form 1.1 as discussed in the confidentiality applications submitted with these forms.

Form 1.2 Distribution Area Net Electricity for Generation Load

PG&E has no reason, at this time, to expect a material change in departing load relative to historic trends which are captured in the forecast sales and load figures. As described in Form 1.1, DA is assumed to remain constant at current levels, and this assumption is true for Community Choice Aggregation as well. CCA is currently zero. Load reductions due to customer self-generation programs in the period 2009 through 2020 are included in the forecast consistent with the 2006 LTPP. Column L, uncommitted energy efficiency impacts are the CPUC targets described above. Column M does not include the effects of energy efficiency (unmitigated for EE) but does include load reductions for customer self-generation.

PG&E is requesting confidential treatment for various portions of Form 1.2 as discussed in the confidentiality applications submitted with these forms.

Form 1.3 LSE Coincident Peak Demand by Sector (Bundled Customers)

PG&E's peak demand forecast is not produced via an end-use model and, therefore, is not built up from sector-level data. For this reason, in Form 1.3, we are only able to provide aggregate forecast data for bundled customer peaks. PG&E's bundled system peak is a July peak. Bundled customer distribution losses are developed consistent with the distribution loss factor algorithms used in the Settlements process. Transmission losses and unaccounted for energy are assumed to be 2.5% and 0.5%, respectively consistent with resource adequacy counting rules. As in Form 1.1 and 1.2, the effects of customer energy efficiency programs and incremental customer self-generation programs in the period 2009 through 2020 are included in the forecast data.

Form 1.4 Distribution Area Coincident Peak Demand

All assumptions are the same as described in form 1.3, above. Column N does not include the impacts of energy efficiency (unmitigated).

Form 1.5 Peak Demand Weather Scenarios

Forecast data are provided for each of the temperature scenarios requested, except for the 1 in 40 scenario for which we currently do not have a multiplier. Scenario forecasts are produced by simulating the peak demand forecast model over varying assumptions of peak temperature conditions. No historical data are available for these scenarios. All assumptions are the same as described in forms 1.3, above.

Form 1.6 Distribution Area Hourly Load

Form 1.6a Distribution Area Hourly Load

The hourly load files are voluminous, and will be provided only on compact disk. All assumptions described for forms 1.3 and 1.4 are also applicable to the hourly loads in form 1.6.

PG&E is requesting confidential treatment for various portions of Form 1.6a as discussed in the confidentiality applications submitted with these forms.

Form 1.6b Hourly Loads by Transmission Planning Subareas or Climate Zone (IOUs Only)

As in 1.6a above, this hourly data will be provided only on a compact disk. PG&E is providing hourly loads for CAISO's transmission congestion zones, NP15 and ZP26. For 2007 and 2008, the data is based on PG&E's historical hourly load log at generation as reported in Form 714 filed with FERC, and therefore includes bundled service and direct access customer load, distribution and transmission losses, as well as unaccounted for energy. PG&E uses its ISO Settlements data and estimated direct access customers energy to develop NP15/ZP26 proportions that are applied to the historical hourly load log.

PG&E is requesting confidential treatment for various portions of Form 1.6b as discussed in the confidentiality applications submitted with these forms.

Form 1.7 Local Private Supply by Sector or Class

PG&E does not examine this area in detail in developing its demand forecast. Currently, there are no reliable historical or forecast data that may be used to complete these tables.

2. Forecast Input Assumptions

Form 2.1 State or National Economic and Demographic Inputs

PG&E does not use national or statewide projections to develop its demand forecasts.

Form 2.2 Planning Area Economic and Demographic Assumptions

Form 2.2 provides the recorded and projected economic and demographic variables used in PG&E’s demand forecasts. The projections are specific to PG&E’s service territory and are from Economy.com’s December 2008 forecast.

Although Economy.com allows us to share these with our regulators, the CEC must receive permission from Economy.com should it wish to publish this data in its report.

Form 2.3 Electricity Rate Forecast

PG&E does not use an electric rate forecast to develop its demand electric sales and load forecasts. Instead PG&E uses simple residential and commercial price drivers. The residential and commercial price drivers are not forecasts of residential and commercial rates. The residential price driver represents the average price faced by the majority of residential customers. The commercial price driver represents the average price faced by the majority of commercial customers. The forecast price drivers are escalated by the consumer price index.

Form 2.4 Customer Count & Other Forecasting Inputs

Form 2.4 provides recorded and projected customer counts by customer class. The data reported is billing data (number of bills), which is used to represent number of customers. The annual numbers reported are averages of 12 months of customer data. Form 2.4 also notes other forecasting inputs PG&E used to derive its customer and demand forecasts.

3. Demand Side Management (DSM) Program Impacts

Energy Efficiency Program Costs and Impacts (Forms 3.1a, 3.1b and 3.2)

The CEE program costs and energy savings impacts provided for programs years 2006 through 2011 in Forms 3.1a, 3.1b, and 3.2 are derived from PG&E's Long-Term Procurement Plan ("LTPP") filing before the California Public Utility Commission in Docket No. R06-02-013, dated March 2007. For program years 2012 through 2020, the gross energy savings goals are those adopted by the CPUC in Decision 08-07-047, August 1, 2008.

<u>For Program Years 2006 through 2008</u>

The CEE program costs and impacts provided in Forms 3.1a, 3.1b, and 3.2 are derived from PG&E's recently filed LTPP. In that filing, PG&E used the CPUC's adopted levels for 2007 and 2008. For 2006 in the IEPR, PG&E used the difference between the levels adopted by the CPUC for 2006-2008, and the levels shown for 2007 and 2008.

<u>For Program Years 2009 through 2011</u>

Currently, there is no CEE program funding adopted by the CPUC for program years cycle from 2009 through 2011, pending CPUC's approval on PG&E's CEE 2009-2011 Amended Application filed on March 2, 2009. However, the effective annual and cumulative energy savings goals for program years 2009 through 2011 listed in Forms 3.1a and 3.2 are adopted by the CPUC in Decision 04-09-060. The CPUC has stated it plans to revisit these adopted goals based on updated savings potential studies, changes to mandatory efficiency standards and, other evaluation studies.

For PG&E, the annual energy savings goals from 2009 through 2011 are as follows (annual peak derived as the difference in the adopted cumulative figures):

	Peak Savings (MW) (Annual)	Annual Electric (GWh/yr)	Annual Gas (MMTh/yr)
2009	231	1,067	20.3
2010	220	1,015	21.1
2011	236	1,086	22.0

For Program Years 2012 through 2020

The effective interim annual and cumulative energy savings goals for program years 2012 through 2020 were adopted by the CPUC in Decision 08-07-047, August 1, 2008. As stated in D.08-07-047, the CPUC may adjust the schedule for updating and establishing new energy savings goals for 2012 through 2020 after the 2006-2008 Impact Evaluation studies are completed (expected to be March 2010) and the inquiry shall be completed by October 2010. Currently, there is no CEE program funding adopted by the CPUC for program years from 2012 through 2020. For PG&E, the annual energy savings goals adopted in D.08-07-047 from 2012 through 2020 are as follows:

	Peak Savings (MW) (Annual)	Annual Electric (GWh/yr)	Annual Gas (MMTh/yr)
2012	253	978	20
2013	237	867	32
2014	228	793	31
2015	241	765	32
2016	257	787	32
2017	258	797	31
2018	270	814	32
2019	270	816	32
2020	269	817	33

Energy Efficiency Program Costs Calculations and assumptions (Forms 3.1a, 3.1b and 3.2)

For Program Years 2006 through 2008

As stated above, the CEE program costs provided in Forms 3.1a, 3.1b, and 3.2 are derived from PG&E's recently adopted 2006 LTPP. In that filing, PG&E used the CPUC's adopted levels for 2007 and 2008. For 2006 in the 2007 IEPR submittal, PG&E used the difference between the levels adopted by the CPUC for 2006-2008, and the levels shown for 2007 and 2008.

Although the 2006-2008 program costs are known, the energy savings for this period are unknown. Since energy savings impacts cannot yet be updated, from those reported in the 2007 IEPR, PG&E opted for consistency for all of the data within Form 3 by keeping the 2007 IEPR reported dollars, which are also consistent with the prior long-term plans for these three years.

For Program Years 2009 through 2011

PG&E used the same approach used in the 2006-2008 for the 2009-2011 period. That is, in Forms 3.1 and 3.2, PG&E opted for consistency by keeping the 2007 IEPR reported expenditures, which are also consistent with the prior long-term plans for these three years. PG&E recently refilled its 2009-2011 filing on March 2, 2009. PG&E has reflected this new 2009-2011 energy efficiency filing in limited ways in this IEPR response, as discussed below, and will work with the CEC staff in this forum and in its Demand Forecast Energy Efficiency Quantification Project (DFEEQP) working group to assure that our CEE 2009-2011 Amended Application filed on March 2, 2009 is widely available and well understood.

For Program Years 2012 through 2020

For this period, 2012-2020, PG&E has updated program costs from what was reported the 2007 IEPR filing. For CEE impacts for these years, we use the energy savings goals adopted by the CPUC in Decision 08-07-047, August 1, 2008. However, since the program funding for these years has not been adopted by the CPUC yet. We used preliminary information from our recent CEE filing to derive an approximation of what it would cost to deliver those energy savings targets.

To estimate the program cost for units reported in the 2007 IEPR filing, PG&E used a multiplier that consists of the average cost per kWh from the 2009-2011 CEE filing of March 2nd. Program costs per year for the 2012-2020 years were calculated by dividing the 2009-2011 projected program cost by the 2009-2011 KWh gross energy savings targets. PG&E then used this average unit cost and multiplied by the LTPP energy savings impacts reported in the 2007 IEPR filing

The same method above was used for computing the project cost associated with gas savings. PG&E used a multiplier that consists of the average cost per therm fro the 2009-2011 CEE filing. PG&E calculated program costs per year by dividing the 2009-2011 projected program costs by the 2009-2011 gross therm targets. PG&E then used this average unit cost and multiplied by the gas energy savings impacts reported in the 2007 IEPR filing. It should be noted that these electricity costs values are different than those used in the Revenue Requirement Form 8.1. In Form 8.1, as described below, we attempted to better model expected revenue requirements by reflecting our preferred scenario for the program years 2009-2011 as filed in our March 2, 2009 CEE filing, and extrapolated future year expenditures as the average of those three years.

Form 3.3 Renewable and Distributed Generation Program Costs and Impacts

PG&E has included the impacts the California Solar Initiative as well as customer self-generation programs consistent with those developed for the 2006 Long Term Procurement Plan.

Form 3.4 Demand Response Program Costs & Impacts

The Demand Response (DR) program impacts ("load impact estimates") included in Form 3.4 for the years 2009 through 2020 are based on Table 5-7 of PG&E's 2009-2011 Demand Response Programs and Budgets Application (A.08-06-003), which was filed with the CPUC on September 19, 2008. For a discussion of the derivation of the numbers in the Application, see Chapter 5 of the Amended Prepared Testimony, pp. 5-10 to 5-25. The figures presented in the Application only cover years 2009-2011, therefore PG&E made modifications to the estimates (discussed below) to fulfill the CEC's request.

Pursuant t o CPUC Decision D.08-04-050, PG&E is preparing a forecast of ex ante load impact estimates for its DR portfolio for years 2009-2020. This forecast, as directed by the CPUC in its decision (Ordering Paragraph 5), will be used across all PG&E filings that require forecasted information regarding DR programs (e.g. LTPP and Resource Adequacy filings). The CPUC's annual filing deadline for the ex ante load impact estimates is April 1st unless otherwise extended by the CPUC. Energy Division has granted PG&E an extension on the ex ante portion of its 2009 load impact evaluation filing until May 1, 2009 (with the exception of SmartAC ex ante load impact estimates for years 2009 and 2010, which are due April 1, 2009). As such, the updated 2009-2020 load impact estimates were not available for use in development of the 2009 IEPR forecast. Instead, PG&E took the ex ante load impact estimates from Table 5-7 of the 2009-2011 DR Application and extended them through 2020, with the following exceptions:

- For 2009, adjustments were made to the Aggregator Managed Portfolio (AMP) and SmartAC programs to reflect operational realities. For years 2010-2020, the figures for these programs reflect a simple extension of the figures in Table 5-7.

- For 2012-2020, the PeakChoice program reflects 8% annual growth of the non-Base Interruptible Program (BIP) component of the program, while the BIP component is assumed to remain constant.

- For all years, SmartRate Program figures are based on the case presented in PG&E's Proposed Upgrade to the SmartMeter Program (A.07-12-009), and adjusted to reflect the uncertainty surrounding program performance of a brand new program deployment. Since SmartRate became operational in summer 2008, PG&E did not develop formal load impact estimates for this program for use in the 2009-2011 DR Application. PG&E is therefore continuing to use the figures presented in A.07-12-009 (uncertainty adjusted) until the 2009-2020 ex ante load impact estimates are finalized in May 2009.

Additionally, the DR forecast presented in this 2009 IEPR filing does not take into consideration the ramifications of CPUC D.08-07-045, which mandates that PG&E file proposed default dynamic pricing rates for all non-residential customers and new optional dynamic pricing rates for residential customers. On February 27, 2009 PG&E filed A.09-02-022, which contains the proposed dynamic rates. The 2009-2020 ex ante load impact estimates that PG&E will file with the CPUC pursuant to D.08-04-050 will reflect rates proposed in A.09-02-022.

The entire DR forecast presented in this 2009 IEPR filing will be updated to reflect PG&E's portfolio forecast of DR ex ante load impacts through 2020. PG&E will provide the CEC with an updated DR forecast as it becomes available.

Form 4 Report on Demand Forecast Methods and Models

An overview of the forecast methodology may be found in the testimony provided in PG&E's 2009 ERRA filing (A.08-06-011 (Chapter 2)). Details regarding the forecast including forecast equations, etc. may be found in the workpapers associated with the above referenced filings. If the CEC does not already have these documents, please contact PG&E and we will provide them to you.

Form 5 Committed Demand-Side Program Methodology

Efficiency Program Costs and Impacts

See the discussion under Form 3.1a, 3.1b, and 3.2 above and PG&E's 2006 Long-Term Procurement Plan (R.06-02-013), March 5, 2007, Volume 1, Section IV.

In general, the assumptions used to calculate net energy savings impacts such as the effective useful lives of energy efficiency measures, net-to-gross ratios, per-unit energy savings, and incremental measure costs are derived as described in the CPUC Energy Efficiency Policy Manual. Also, PG&E uses the Database for Energy Efficiency Resources (DEER) for some of the per-unit energy savings assumptions and incremental measure costs. If the source of the per-unit energy savings assumption or incremental measure cost is not in the DEER, documentation supporting the inclusion of the new information is identified in PG&E's work papers.

Demand Response

See the discussion under Form 3.4 above.

Form 6 Uncommitted Demand-Side Program Methodology

Energy Efficiency

See the discussion under Form 3.1a, 3.1b, and 3.2 above and PG&E's 2006 Long-Term Procurement Plan (R.06-02-013), March 5, 2007, Volume 1, Section IV.

In general, the assumptions used to calculate net energy savings impacts such as the effective useful lives of energy efficiency measures, net-to-gross ratios, per-unit energy savings, and incremental measure costs are derived as described in the CPUC Energy Efficiency Policy Manual. Also, PG&E uses the Database for Energy Efficiency Resources (DEER) for some of the per-unit energy savings assumptions and incremental measure costs. If the source of the per-unit energy savings assumption or incremental measure cost is not in the DEER, documentation supporting the inclusion of the new information is identified in PG&E's work papers.

PG&E has developed energy efficiency programs for the 2009-2011 supplemental filing submitted to the CPUC on March 2. The CPUC's plan is to approve the supplemental filing this year. The energy savings impacts given in this data response reflect the most recently Commission adopted targets and are consistent with the targets assumed in the development of the load forecast in this data response. PG&E's new impact projections associated with the 2009-2011 supplemental filing are designed with the same regulatory mandated targets in mind. In some cases the "design target" of the recently filed programs may have a value higher than the current adopted targets; PG&E has not reflected any incrementally higher possible impacts in this data response.

Demand Response

All PG&E DR programs included in this IEPR forecast (both dispatchable and non-dispatchable) are considered "committed" according to the definition in the Demand Forecast Forms and Instructions for the 2009 Integrated Energy Policy Report: "For the IOUs, committed conservation programs are those programs to be included in the 2009-2011 program plans anticipated to be approved in…CPUC decisions" (p.5).

Form 8. Revenue Requirement and Sales Forms

Form 8.1a asks for both historical and forecasted prices. In our response, PG&E has provided authorized revenue requirements for 2006 through 2009,, and then two differing forecasts for 2010 through 2020. As with most forecasting exercises, these forecasts are predicated on a number of assumptions, and will be impacted by future events and regulatory decisions that have not been taken into account. Future regulatory filings may contemplate or propose different costs or rate treatments. Thus, PG&E does not purport that the information contained in this response will reflect actual future rates, revenue requirements, or sales.

Years 2006-2008 – PG&E is providing authorized revenue requirements. The following is a list of sources of authorized revenue requirements:

- 2006 - AL 2706-E-A, Annual Electric True-up Filing, page 9
- 2007 - AL 2895-E-A, Annual Electric True-up Filing, page 9
- 2008 – AL 3115-E-A, Annual Electric True-up Filing, page 8

The Utility Retained Gen (URG) excludes fuel. URG fuel is included in the Energy Resource Recovery Account (ERRA) Revenue Requirement (RRQ) which is included with the Supply Contracts costs. Provisions for franchise fees and uncollectibles (FF&U) are included with each cost component except for DWR Power and Bond costs. The DWR-related provisions for FF&U are shown on the line for "Taxes and Franchise Fees".

Year 2009 - Revenue Requirement projections in 2009 reflect PG&E's authorized revenue requirements as of March 1, 2009.

Years 2010-2020: Generation Revenue Requirements -- the generation costs are provided for two scenarios. The costs rely on numerous assumptions such as load growth, gas prices, the timing and type of demand-side resources, the timing and type of renewable resources, assumptions about retirements of existing generation, and the timing and type of new, operationally flexible conventional generation. These scenarios can be characterized as:

- Scenario 1 – 20% RPS target by 2013
- Scenario 2 – 33% RPS target by 2020

There are 4 2009 IEPR forms that are affected by these scenarios (forms S-1, S-2, 8.1a, and 8.1b). These scenarios represent alternative views of future RPS resource levels. The effective difference between the two scenarios in Form 8.1a can be seen in these forms only in the 2013-2020 time-horizon since the percentage of RPS resources in PG&E's portfolio is assumed to be the same through 2014 in both scenarios but transmission requirements diverge between the scenarios starting in 2013. Scenario 1 has forecasted RPS resources to meet a 20% minimum RPS target by 2013 and beyond, while Scenario 2 accelerates RPS resource additions more quickly beginning in 2015 to achieve a 33% RPS target by 2020.

PG&E combined a limited number of generation subtotal lines in both 8.1a forms. Specifically, PG&E combined "Qualifying Facility" costs with "Non QF Renewables" costs, and merged "residual market transactions" with "other resources."

PG&E assumed non-generation costs would be largely unaffected by electric procurement decisions, except for transmission construction.

PG&E did not break out CTC for the years beyond 2009 in the form 8.1a. After 2009, CTC is an unspecified component of the generation revenue requirement.

Years 2010-2020 - Non-generation Revenue Requirements -- PG&E drew from internal forecasts of capital expenditures, rate base additions, depreciation, and operating expenses to forecast revenue requirements for non-generation costs for transmission, distribution, and other charges and fees. For some line items, PG&E simply applied an escalation factor. All data is shown in thousands of nominal dollars.

PG&E is requesting confidential treatment for various portions of Form 8.1a as discussed in the confidentiality applications submitted with these forms.

Form 8.1b Revenue Requirements Allocation by Bundled Customer Class and for Direct Access Service Customers (provided as two forms)

These values apportion the revenue requirements in 8.1a (for both scenarios) to the different rate classes. Allocations were based upon class average data as of 3/1/2009.

Form 8.2 Seasonal Residential Electricity Sales by Baseline Percentages in 2006, 2007, and 2008 for Basic Accounts and All-Electric Accounts (provided as ten forms)

The completed forms are supplied in the excel sheets. Please note that the customer count represents the number of customer bills that contributed to the kWh shown in the corresponding tier. An individual customer bill may be counted multiple times in any month depending on the total kWh for that bill. For example, if a customer bill reached kWh equal to 30% of baseline usage during a month, then that bill would be counted three times - once in the 0 to 10% of baseline tier, once in the 10% to 20% of baseline tier and once again in the 20% to 30% of baseline tier.

Supply Forms

Form S-1, Capacity Forecasts

For the forecast period (2009-2020):

Annual peaks are represented by the month of August for all years as this is the month that the forecasted procurement load, Line 14 “Firm LSE Peak-Hour Resource Requirement,” is forecasted to be the highest.

PG&E is submitting two scenarios in this 2009 IEPR filing:

- Scenario 1 – 20% RPS target by 2013
- Scenario 2 – 33% RPS target by 2020

There are 4 2009 IEPR forms that are affected by these scenarios (forms S-1, S-2, 8.1a, and 8.1b). These scenarios represent alternative views of future RPS resource levels. The effective difference between the two scenarios in Form S-1 and S-2 can be seen in these forms only in the 2015-2020 time-horizon since the percentage of RPS resources in PG&E’s portfolio is assumed to be the same through 2014 in both scenarios. Scenario 1 has forecasted RPS resources to meet a 20% minimum RPS target by 2013 and beyond, while Scenario 2 accelerates RPS resource additions more quickly beginning in 2015 to achieve a 33% RPS target by 2020.

Specifically for Form S-1, the differences between the scenarios are limited to Line 26 “Generic Renewable Resources.” To contrast the two scenarios, PG&E has modified Form S-1 by adding Lines x26-x28 (which represent Scenario 2) and are analogous to the original Lines 26-28 (which represent Scenario 1). All other lines for all years (i.e., Lines 1a-25) are exactly the same in both scenarios and are only represented once.

For the historical period (2007-2008):

PG&E does not have the data required to populate Line 9 “Adjusted-Peak-Hour Demand: End Use Customers” on a historical basis. Therefore, this line as well as all subsequent lines that use this value as part of a calculation (i.e., Lines 12a, 14, 25, & 29-33) are either blank or zero.

For supply resources, values do not necessary represent actual peak capacity that was realized in the historical period. Rather, they represent a reasonable approximation of likely peak capacity.

PG&E is requesting confidential treatment for various portions of Form S-1 as discussed in the confidentiality applications submitted with these forms.

Form S-2, Energy Resources

For the forecast period (2009-2020):

As discussed in Form S-1, PG&E is submitting 2 scenarios in this 2009 IEPR filing:

- Scenario 1 – 20% RPS target by 2013
- Scenario 2 – 33% RPS target by 2020

Specifically for Form S-2, the differences between the scenarios are limited to Lines 23-29c. To contrast the two scenarios, PG&E has modified Form S-2 by adding Lines x23-x29c (which represent Scenario 2) and are analogous to the original Lines 23-29c (which represent Scenario 1). All other lines for all years (i.e., Lines 1a-22) are exactly the same in both scenarios and are only represented once.

The hydroelectric data for 2009 was based on current precipitation and generation forecasts for calendar year 2009. While the forecast for 2010 though 2020 is based on average year generation, the current forecast for 2009 depicts generation which is lower than average, and is much closer to an extreme 1-in-5 forecast.

For the historical period (2007-2008):

The data required to populate Line 9 "Adjusted Energy Demand / Consumption" on a historical basis can be calculated from the data presented on Form 1.2 and are not shown in Form S-2. Therefore, this line as well as all subsequent lines (i.e., lines 11, 22, 26h, & x26h) that use this value as part of a calculation are either blank or zero.

While the historical energy for each QF technology is not disaggregated on Lines 17b-17h, PG&E shows the requested historical renewable energy associated with QFs on Lines 26b, 29a, x26b, & x29a. These energy values are subsumed in Line 17a "Total Energy Supply from QF Contracts."

PG&E is requesting confidential treatment for various portions of Form S-2 as discussed in the confidentiality applications submitted with these forms.

Form S-5 Bilateral Contracts

Form S-5 provides the requested categorical and numeric information regarding electricity supply through bilateral contracts. PG&E is submitting this information for a total of 49 contracts (10 non-renewable energy, 39 renewable energy). The input data for the "Capacity of the Unit(s)" category provides a reference to a line item in Form S-1 of this 2009 IEPR filing.

In the limited areas where information is marked as "N/A," this implies that the category was not applicable or not available.

PG&E is requesting confidential treatment for various portions of Form S-5 as discussed in the confidentiality applications submitted with these forms.