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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company To Revise Its Electric Marginal Costs, Revenue Allocation, and Rate Design. (U 39 M)	Application 06-03-005 (Filed March 2, 2006)

ASSIGNED COMMISSIONER'S RULING REQUESTING COMMENTS ON DRAFT TIMETABLE AND RATE GUIDANCE AND UPDATING SCHEDULE

This ruling requests comments from parties on draft proposals that are attached to the ruling, assigns a specific follow-up task to Pacific Gas and Electric Company (PG&E), and updates the schedule for the proceeding.

The August 22, 2007 Supplemental Scoping Memo and Assigned Commissioner's Ruling (ACR) included a list of issues related to the design of dynamic pricing rates. Parties were directed to file comments on the issues list. Eleven parties filed opening comments on the list of issues on October 5, 2007.[1] Eight parties filed reply comments on October 19, 2007.[2] Two days of workshops

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[1] The parties that filed opening comments are Building Owners and Managers Association (BOMA); California Large Energy Consumers Association (CLECA); California Manufacturers and Technology Association (CMTA); California Rice Millers (CRM); Division of Ratepayer Advocates (DRA); Ice Energy; Pacific Gas and Electric Company (PG&E); San Diego Gas & Electric Company (SDG&E); Southern California Edison Company (SCE); The Utility Reform Network (TURN); and Western Power Trading Forum (WPTF).

[2] The parties that filed reply comments are BOMA, CLECA, CMTA, DRA, PG&E, SDG&E, SCE, and TURN.

were held on November 5 and 6, 2007 at which key issues identified by parties in comments were discussed. Ten parties filed post-workshop comments on December 11, 2007.[3]

The draft proposals attached to this ruling have been prepared based on the comments filed by parties and the workshops.

1. Draft Timetable and Rate Design Principles

As described in the July 25, 2006 ACR, the primary objective of this phase is to create a year-by-year strategic work plan that will direct PG&E to develop and integrate dynamic pricing rates into PG&E's rate design for all customers by 2011. The strategic work plan should answer three questions:

1) What types of dynamic pricing tariffs should PG&E offer to its customers?
2) When should PG&E offer each type of dynamic pricing tariffs to each customer class?
3) How should the dynamic pricing tariffs be designed and integrated into PG&E's overall rate design?

Attachment A contains draft answers to these questions taking into account comments filed by parties and the workshops.

1.1. Timetable for PG&E Rate Proposals

The first part of Attachment A titled "Timetable for PG&E Rate Proposals" contains draft answers to questions 1 and 2. The first part of the timetable is organized by customer type. For each customer type the timetable summarizes the rate offerings that are currently available and identifies dates by which PG&E

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[3] The parties that filed post-workshop comments are BOMA; California Farm Bureau Federation (CFBF); CLECA; CMTA and Energy Producers and Users Coalition, jointly (CMTA/EPUC); CRM; DRA; PG&E; SDG&E; SCE; and TURN.

should make specific rate proposals. Parties are directed to comment on the draft timetable.

The following sections highlight some of the considerations that went into developing the draft timetable and includes some specific requests for comments:

Real Time Pricing (RTP)

PG&E argues that 12 to 18 months of experience are needed with the California Independent System Operator's (CAISO's) day-ahead market before developing dynamic pricing based on that market.[4] CMTA/EPUC generally agrees with PG&E that the new day-ahead market should be monitored for 12 to 18 months before implementing RTP.[5] BOMA, on the other hand, disagrees and thinks that the utilities should begin developing RTP rates in mid-2008 with the expectation that rates will be modified over time.[6]

The draft timetable would require PG&E to propose its first RTP rate, for large commercial and industrial (C & I) customers, at the beginning of 2009 with an effective date at the beginning of 2010. If the day-ahead market begins operating on April 1, 2008, this timeline would allow for 9 months of experience with the new market before proposing the new RTP rate and 21 months experience before the rate becomes available to customers. At a January 17, 2008 MRTU implementation workshop, the CAISO indicated that the start date will not be April 1, 2008, but the CAISO indicated its desire to implement the new

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[4] PG&E Post Workshop Comments, p. 2.

[5] CMTA/EPUC Post Workshop Comments, p. 3.

[6] BOMA Post Workshop Comments, p. 7.

market before the summer of 2008.[7] A delay beyond the summer could require a delay in the implementation in RTP.

The timetable proposes that RTP for large agricultural customers follows one year later in 2011. RTP could also be available in 2011 for residential customers, small and medium C & I customers and small and medium agricultural customers on a voluntary basis.

Residential Rates

The timetable for residential customers includes two different scenarios—one assuming that the AB 1X rate protections remain in place throughout the time period and one assuming that AB 1X rate protections are no longer in place.[8] The timetable does not make any assumptions about when AB 1X rate protections will end or whether AB 1X rate protections should end.

The scenario that assumes AB 1X rate protections remain in effect further assumes that residential customers can only be offered time-of-use (TOU), critical peak pricing (CPP), and RTP on a voluntary basis.[9] Customers could be

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[7] See CAISO, MRTU Implementation Workshop, January 17, 2008 (http://www.caiso.com/1f51/1f5178ef434a0.pdf).

[8] AB 1X refers to Assembly Bill No. 1 from the 2001-2002 First Extraordinary Session as codified by Water Code section 80000 et seq. Water Code section 80110 protects the rates of residential customers for usage up to 130 percent of baseline quantities "until such time as the [Department of Water Resources] has recovered the costs of power it has procured for the electrical corporation's retail end use customers…."

[9] Time-of-use (TOU): A rate in which predetermined electricity prices vary as a function of usage period, typically by time of day, by day of week, and/or by season.

Critical Peak Pricing (CPP): A dynamic rate that allows a short-term price increase to a predetermined level (or levels) to reflect real-time system conditions.

Footnote continued on next page

placed on a peak time rebate (PTR) on a default basis.[10] There is no intention to address legal interpretations as to AB 1X in this proceeding. However, if the Commission determines in any other forum that time variant or dynamic pricing rates could be offered to residential customers on a default or mandatory basis before AB 1X protections are totally removed, this assumption would be reconsidered.

PG&E currently has voluntary TOU and CPP rates for residential customers. A proposal for a new PTR is before the Commission in A.07-12-009, PG&E's application to upgrade its AMI project. The draft timetable would not require PG&E to propose any additional rates while AB 1X rate protections remain in place. The Commission would evaluate PG&E's existing residential CPP rate and new PTR proposal in either A.07-12-009, in this proceeding, or in some other docket.

Parties identified several concerns with the PTR including the accuracy of the customer baselines and the potential for "free riders." These issues and others should be considered by the Commission during the evaluation of an actual PTR rate.

Large C & I Customer Rates

Comments and the workshop discussion clarified that large C & I customers generally do not support CPP as a default rate. Nevertheless, the

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Real-Time Pricing (RTP): A dynamic rate that allows prices to be adjusted frequently, typically on an hourly basis, to reflect real-time system conditions. (Glossary of Retail Electricity Rate Terms, Attachment A to D.03-03-036.)

[10] Peak Time Rebate (PTR): A program that provides customers a rebate for demand reductions below a customer-specific baseline when the program is called due to market or system conditions.

Commission has previously ordered the utilities to propose default CPP for customers with maximum load of 200 kW and above.[11] The draft timetable is consistent with previous Commission directives. However, the timetable also recognizes that with the start-up of the MRTU day-ahead market in 2008, RTP rates can be developed during the next several years. Some large customers expressed a preference for RTP over CPP because RTP more closely reflects marginal cost. Therefore, the draft timetable would require PG&E to propose offering large C & I customers a choice of either CPP or RTP starting in 2010. PG&E would propose making RTP the default rate in 2011.

This proposal does not specify whether CPP or RTP should be the default rate in 2010. One possibility would be to require every large C & I customer to make an affirmative choice between an RTP or CPP rate. Another option would be for PG&E to propose either the RTP or CPP rate as a default and provide an opportunity to opt-out to the other rate. In either case, customers would also have an opportunity to opt-out to a TOU rate following a one-year period on a dynamic pricing rate during which bill protection would be in place. Parties should comment on these alternatives.

Agricultural Rates

CFBF notes the popularity of TOU rates among agricultural customers who has shifted their load to the benefit of agricultural customers and the grid. CRM further argues that large agricultural customers would like new TOU

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[11] See D.05-04-053, Ordering Paragraph (OP) 2 and D.06-05-038, OP 2. Strong peak demand signals 6. In D.05-04-053 the Commission stated that "[a]ll bundled customers should receive price signals, regardless of their load shape or size, that indicate when power is more expensive to procure" (Conclusion of Law 6).

options with more time periods. Both CFBF and CRM believe that any dynamic pricing rates should be voluntary at this stage.[12]

The draft timetable takes into consideration the comments of the agricultural parties that have filed comments in this proceeding. The timetable divides agricultural customers into two categories—large agricultural (defined as those with maximum load of 200 kW and above) and small and medium agricultural (defined as those with maximum load less than 200 kW). The 200 kW cut-off is intended to distinguish between those customers that already have interval meters and those customers that will receive interval meters through PG&E's AMI deployment. According to the draft timetable, small and medium agricultural customers that have interval meters would begin to be placed on a default TOU rate in 2010. Large agricultural customers would be required to move to a CPP or RTP rate starting in 2011. However, they would have the option to opt out to a TOU rate. The date of 2011 is intended to provide time for customer education and the development and deployment of enabling technologies.

1.2. Rate Design Guidance

Do wholesale market prices for energy reflect the total marginal cost of generation?

Parties generally agree that in today's California market some capacity costs are not reflected in wholesale energy prices. Some suggest that because resource adequacy requirements give generators an opportunity to sign contracts for capacity, generators do not need to cover all of their costs through the sale of

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[12] CFBF Post Workshop Comments, pp. 3-4; CRM Post Workshop Comments, pp. 2-4.

energy. However, parties can only speculate as to whether the capacity costs that are not reflected in energy prices are small or large. Several parties recommend that the Commission carefully examine this issue.[13]

Once the amount of capacity costs not reflected in energy prices is estimated, the utilities will have several rate design options to reflect capacity costs including the following:

- a flat adder or a percentage adder that allocates costs across all time periods;
- an on-peak energy cost adder or critical peak price that allocates costs to peak or critical peak periods;
- fixed monthly customer charges; or
- demand charges based on maximum monthly demand during peak periods or during all time periods.

These issues require careful consideration. At this stage, I believe the most appropriate place to determine the relationship between energy prices and the total marginal cost of generation and the appropriate method to allocate capacity costs is during the consideration of specific rate designs such as RTP. This is noted in the draft rate design guidance below.

Hedging Premium

The draft rate guidance does not require inclusion of a hedging premium or discount when developing dynamic pricing rates. The more fundamental concept contained in the guidance is that costs should be based on cost causation. If it is less expensive to serve the customers on a given dynamic pricing rate, then the rate should reflect that lower cost to serve.

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[13] For example, BOMA Post Workshop Comments, pp. 5-6 and CMTA/EPUC Post Workshop Comments, p. 2.

In opening comments TURN put forward a proposal that the planning reserve margin for a load serving entity (LSE) could be reduced if the LSE's customers are on dynamic pricing and are, therefore, willing to face high prices during scarcity conditions. In this case the customers on the dynamic pricing rate should see a rate reduction that mirrors the lower planning reserve margin associated with their load. The Commission may choose to consider TURN's proposal in the upcoming Order Instituting Rulemaking on the planning reserve margin.

Other Issues

CMTA/EPUC emphasized the importance of having timely access to hourly usage information so that customers can take action based on timely pricing signals.[14] I intend to examine this issue further in the context of enabling technologies later in this phase.

2. Assigned Tasks

The schedule contained in the August 22, 2007 ACR indicated that this ruling would assign specific tasks to parties. We have identified one follow-up task which will be assigned to PG&E and is described in this section.

PG&E and several other parties have indicated an interest in revising PG&E's existing large customer CPP rate in order to more fully integrate the CPP rate into the underlying rate design. To that end we direct PG&E to put together an analysis of several straw rate alternatives. This section describes the minimum number of rate types that PG&E should evaluate and the minimum

[14] CMTA/EPUC Post Workshop Comments, p. 7.

analysis. PG&E can provide additional rate options and analysis that it believes would assist parties and Commission.

PG&E should identify the three large customer rate schedules that represent the most load. PG&E's straw rate analysis should be based on rates that are substantially similar to those top three rates.

PG&E should also select at least three typical load shapes for customers on each of the three rate schedules—the average load shape for customers on each schedule, a "peakier than average" load shape, a flatter than average load shape. If the load shapes of the customers on each of the three schedules are substantially similar then PG&E can use the same three typical load shapes for each schedule.

PG&E should also consider at least four scenarios in which each typical customer drops load during the CPP period—no load drop, a ten percent load drop, a twenty percent load drop, a thirty percent load drop.

PG&E should evaluate the following straw rate types:

- The current E-CPP rate
- A CPP rate that is consistent with the settlement agreement filed in A.05-01-016 et al. on November 14, 2005
- A CPP rate similar to the rate in the November 14, 2005 settlement agreement that only reduces the generation demand charges to offset the CPP charge

The bill impact analysis should show the impact on each indicative customer of moving between the standard non-CPP rate and each of the alternative CPP rates under each of the load drop scenarios. PG&E should report the results numerically and graphically if PG&E can design a graphical depiction that will help the Commission and other parties understand the impacts.

PG&E should prepare to present the straw rate analysis at a workshop indicated on the attached schedule.

3. Schedule

Attachment B is a revised schedule for the Dynamic Pricing Phase. The schedule is substantially similar to the schedule attached to the August 22, 2007 ACR. Parties are directed to file comments on the draft Timetable for PG&E Rate Proposals and draft Rate Design Guidance by February 14, 2008. February 14, 2008 is also the deadline for PG&E to file its straw rate analysis of alternative CPP rates for large customers. The filing of PG&E's straw CPP rates will be followed by a workshop at which PG&E, other parties and Commission staff can review and discuss the straw rate and related analysis.

Demand Response Research Center (DRRC) Rates Project

The DRRC's Rates Project is ongoing. If the DRRC holds additional workshops and issues reports I will consider whether and how to incorporate those efforts into this proceeding and provide additional guidance.

Customer Education and Enabling Technologies

The issues list attached to the August 22, 2007 ACR identifies several issues related to customer education and enabling technologies. A future ruling will solicit additional comments from parties on these issues which may be followed by a workshop as indicated in the revised schedule.

Evidentiary Hearings

The August 22, 2007 ACR gave parties until November 27, 2007 to file motions for evidentiary hearings. The ALJ extended the deadline until December 11, 2007. TURN filed a conditional motion for evidentiary hearings on December 11, 2007. TURN's motion stated that they would seek evidentiary hearings if the Commission intends to consider policies that would establish default or mandatory time-differentiated rates for residential customers.

At this stage I do not see a need for evidentiary hearings. The issues in this phase, for the most part, involve policy and legal conclusions. Thus far, no party has demonstrated a disputed material issue of fact that would affect our deliberations. Accordingly, the schedule does not provide for evidentiary hearings. If we determine that evidentiary hearings are necessary then the schedule will be revised.

4. Other Matters

TURN's post-workshop comments included an appendix that provided analysis on residential electric consumption for SCE's and SDG&E's customers. TURN requested the opportunity to supplement the appendix with data from PG&E when it becomes available. We hereby grant TURN's request to supplement the record with data from PG&E.

Therefore, **IT IS RULED** that:

1. A draft timetable for Pacific Gas and Electric Company (PG&E) rate proposals, draft rate design guidance and revised schedule are set forth in Attachments A and B of this ruling.

2. Interested parties shall submit comments by February 14, 2008 on the draft timetable and rate design guidance.

3. PG&E shall submit an analysis of straw critical peak pricing (CPP) rate alternatives as described in this ruling by February 14, 2008.

Dated January 23, 2008, at San Francisco California.

/s/ RACHELLE B. CHONG
Rachelle B. Chong
Assigned Commissioner

ATTACHMENT A

Timetable for PG&E Rate Proposals

Residential

While AB 1X rate protections remain in place

Proposal Date	Type of Rate
Current Rate Options	Default five-tier, increasing block rate volumetric energy charge (E-1) Opt-in five-tier TOU (E-6/E-7) Opt-in CPP for customers with interval meters starting 5/1/2008
12/12/2007	In A.07-12-009 PG&E proposed PTR for all bundled customers that are not on CPP. The rate would be available starting in Summer 2010 for customers with interval meters. The existing opt-in CPP rate should also be reviewed in A.07-12-009
by 1/1/2010	Propose opt-in RTP that would be effective on 1/1/2011

After Commission determines AB 1X rate protections end

Proposal Date	Type of Rate
30 days after AB 1X rate protections end	Propose default TOU with CPP with an effective date one year after AB 1X rate protections end. Proposal should give customers the ability to opt out to flat rate or TOU

Small and Medium Commercial and Industrial (maximum demand < 200 kW)

These customers are generally served on A-1, A-6 and A-10 non-TOU.

Proposal Date	Type of Rate
Current Rate Options	Flat volumetric energy charge with customer charge (A-1) Flat volumetric energy charge with customer charge and demand charge (A-10 non-TOU) Opt-in TOU without demand charge (A-6) Opt-in TOU with demand charge (A-10 TOU, E-19) Opt-in CPP for customers with interval meters starting 5/1/2008
By 1/1/2009	Propose default opt-out TOU with CPP for customers with interval meters starting on 1/1/2010. Also propose an opt-in RTP rate available starting 1/1/2011. Proposal should give customers the option to opt-out to a TOU rate

Large Commercial and Industrial (maximum demand of200 kW and above)

These customers are generally served on E-19 and E-20.

Proposal Date	Type of Rate
Current Rate Options	TOU with demand charges Opt-in CPP
By 6/2/2008	Propose a revised CPP rate in which the CPP rate reduces generation demand charges effective 1/1/2009
By 1/1/2009	Propose CPP effective 1/1/2010 Propose RTP effective 1/1/2010[1] Customers must choose CPP or RTP with opt-out to TOU
By 6/1/2010	Propose making RTP default with opt-out to CPP or TOU, effective 1/1/2011

1 Assumes that the CAISO's day-ahead market is running by the summer of 2008.

Agricultural

Proposal Date	**Type of Rate**
Current Rate Options	*Small and Medium Customers (maximum demand < 200 kW)* Non-TOU volumetric energy charge with demand charge (AG-1A, AG-1B) Opt-in TOU with demand charge (AG-4A, AG-4B) *Large Customers (maximum demand of 200 kW and above)* TOU with demand charge (AG-4B, AG-5B, AG-5C)
By 1/1/2009	Propose opt-in CPP for all agricultural customers with interval meters effective 1/1/2010. Propose default TOU effective 1/1/2010 for all small and medium agricultural customers with interval meters. Proposal should give small and medium customers the option to opt out to flat rate or CPP.
By 1/1/2010	Propose opt-in RTP for small and medium customers effective 1/1/2011. Propose that large customers must choose CPP or RTP with the option to opt-out to TOU

Summary

If the Commission adopts rates according to the timetable above, then the following time differentiated rates would be applicable to customers. The table assumes that all customers will have interval meters by the end of 2011:

Customer Group	2008	2009	2010	2011	2012
Residential (Assuming AB 1X rate protections remain in place)	For customers with interval meters: opt-in TOU or opt-in CPP	For customers with interval meters: opt-in TOU or opt-in CPP	For customers with interval meters: default PTR with flat rate, opt-in TOU, or opt-in CPP	For customers with interval meters: default PTR with flat rate, opt-in TOU, opt-in CPP, or opt-in RTP	Default PTR with flat rate, opt-in TOU, opt-in CPP, or opt-in RTP
Residential (post AB 1X)	One year after AB 1X rate protections end: Default CPP with ability to opt-out to TOU or flat rate				
Small and Medium C & I (< 200 kW)	For customers with interval meters: opt-in TOU or opt-in CPP	For customers with interval meters: opt-in TOU or opt-in CPP	For customers with interval meters: default CPP with ability to opt out to TOU. No flat rate option.	For customers with interval meters: default CPP with ability to opt out to TOU or RTP. No flat rate option.	Default CPP with ability to opt out to TOU or RTP. No flat rate option.
Large C&I (200 kW and above)	TOU or opt-in CPP	TOU or opt-in CPP	Choice of CPP or RTP with ability to opt out to TOU	Default RTP with ability to opt out to TOU or CPP	Default RTP with ability to opt out to TOU or CPP
Small and Medium Agricultural (< 200 kW)	For customers with interval meters: opt-in TOU	For customers with interval meters: opt-in TOU	For customers with interval meters: default TOU with ability to opt out to CPP or flat rate	For customers with interval meters: default TOU with ability to opt out to CPP, RTP or flat rate	Default TOU with ability to opt out to flat rate, CPP or RTP
Large Agricultural (200 kW and above)	TOU or opt-in CPP	TOU or opt-in CPP	TOU or opt-in CPP	Choice of CPP or RTP with ability to opt out to TOU	Choice of CPP or RTP with ability to opt out to TOU

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Rate Design Guidance

When PG&E proposes rates pursuant to the timetable above the proposed rates should be consistent with the following guidance. This guidance refers to the generation portion of the rate. The rates for distribution, transmission and non-bypassable costs are not the focus of this guidance.

All Dynamic Pricing Rates

- Rate design should promote economically efficient decisionmaking.
- Rates should reflect marginal cost.
- Prioritizing and balancing marginal cost with other objectives such as energy efficiency and baseline allowances should be addressed when designing specific rates.
- Rates should also seek to provide stability, simplicity, and customer choice.
- If customers on a particular rate reduce their usage in a manner that reduces a utility's costs then the customers on that rate should see a commensurate reduction in their bills.
- Residential rates must compliant with all relevant laws including Public Utilities Code Sections 739 and 739.7 pertaining to residential rates.
- Mandatory and default opt-out dynamic pricing rates should include a capacity reservation charge that allows a customer to pay a fixed monthly charge for a predetermined amount of its load and pay the critical peak price for consumption in excess of the reserved capacity.

Critical Peak Pricing

- Critical peak pricing rates should include a critical peak price during critical peak periods and time-of-use rates for non-critical periods.

- The critical peak price should represent the marginal cost of capacity used to meet peak energy needs plus the marginal cost of energy during the critical peak period.
- The critical peak price should be derived from the cost of a new combustion turbine (e.g. the avoided generation capacity cost per kW-year).
- If a centralized capacity market or bulletin board is established in the future, the critical peak price should be derived from prices established in the centralized capacity market or bulletin board.
- The utilities should be able to call critical peak events on weekends and holidays.
- The utility should be able to call a variable number of events each year, and the rate should be designed based on the number of events that would be called during a typical year.
- Once the CAISO implements scarcity pricing, the Commission should evaluate using scarcity pricing as an additional trigger for CPP events.

Real Time Pricing

- Real-time pricing rates should be developed soon after the CAISO's day-ahead market begins operating.
- The energy charge should be indexed to the CAISO's day-ahead hourly market prices.
- At least initially, RTP should be based on day-ahead hourly market prices that have been aggregated across PG&E's service territory. PG&E should not propose rates that differ by location. As the market develops locational prices should be considered.
- Once the CAISO implements scarcity pricing, the scarcity price should be added to the real-time energy charge if feasible.

- The Commission should determine the degree to which the marginal cost of capacity is not incorporated into the CAISO's day-ahead hourly market prices and propose a combination of demand charges and adjustments to the energy charge to reflect any incremental capacity costs.
- Customers should be offered an opportunity to hedge some of their usage through a mechanism similar to the capacity reservation charge.

(END OF ATTACHMENT A)

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ATTACHMENT B

Schedule

The following is a revised schedule for the Dynamic Pricing Phase:

Date	Action
Feb. 14, 2008	Parties file comments on straw timeline and rate design guidance PG&E files straw CPP rate
Feb. 21, 2008	Workshop on straw CPP rate
Mar. 6, 2008	Post-workshop comments on straw CPP rate
February 2008	Ruling on customer education and enabling technologies
March 2008	Workshop on customer education and enabling technologies
April 2008	Parties file comments regarding customer education and enabling technologies
May 2008	Proposed Decision on Dynamic Pricing policy

The following is a potential schedule for consideration of a new CPP rate for PG&E's customers with maximum demand greater than 200 kW.

Date	Action
June 2, 2008	PG&E files new CPP rate for customers > 200 kW
Nov. 2008	Proposed Decision on new CPP rate for customers > 200 kW

(END OF ATTACHMENT B)

INFORMATION REGARDING SERVICE

I have provided notification of filing to the electronic mail addresses on the attached service list.

Upon confirmation of this document's acceptance for filing, I will cause a Notice of Availability of the filed document to be served upon the service list to this proceeding by U.S. mail. The service list I will use to serve the Notice of Availability of the filed. Document is current as of today's date.

Dated January 23, 2008, at San Francisco California.

/s/ SANDRA M. JACKSON
Sandra M. Jackson