BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing U 39 E	Rulemaking 02-06-001 (filed June 6, 2002)

SUPPLEMENTAL PRELIMINARY BUSINESS CASE
FILING OF PACIFIC GAS AND ELECTRIC COMPANY

LINDA L. AGERTER
PETER OUBORG

Pacific Gas and Electric Company
P.O. Box 7442
San Francisco, CA 94120
Telephone: (415) 973-2286
Facsimile: (415) 973-5520
E-Mail: pxo2@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

January 12, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing U 39 E	Rulemaking 02-06-001 (filed June 6, 2002)

SUPPLEMENTAL PRELIMINARY BUSINESS CASE FILING OF PACIFIC GAS AND ELECTRIC COMPANY

Pursuant to the November 24, 2004 Assigned Commissioner's and Administrative Law Judge's ruling issued in this docket (November 24 ACR), Pacific Gas and Electric Company (PG&E) submits this supplement to its October 15, 2004 Advanced Metering Infrastructure (AMI) preliminary business case analysis.[1]

On July 21, 2004 the Commission issued a ruling requiring the utilities to provide by October 15, 2004 their preliminary business case analyses of AMI (July 21 ACR). PG&E filed its preliminary analysis on October 15; the other utilities filed their respective business cases on October 22. The November 24 ACR stated: "The July 21, 2004 ruling identified numerous scenarios to analyze and assumptions to be described or specified. None of the utilities have fully complied with our directives in the July 21, 2004 ruling although all three have completed much of the analysis that was required."

PG&E believes it has complied substantially with the requirements of the July 21 ACR. The purpose of this supplement is to address the following areas that were not fully covered by PG&E in its October 15 filing:

[1] PG&E notes that it is also currently developing its March 15, 2005 filing, directed by the November 24 ACR, in which it intends to supply a comprehensive update of its October 15 filing.

- Outsourced funding of AMI. In its October 15 filing, PG&E did not have sufficient information to evaluate outsourced meter ownership (i.e., leasing). In PG&E's view leasing meters may not be economical; utility ownership and financing is likely to be the least cost solution. The validity of this assumption has been demonstrated by the responses to PG&E's September 27, 2004 Request for Proposals (AMI RFP): PG&E received no bids proposing to lease AMI meters to PG&E. Nevertheless, based on a single bid proposing to lease an AMI communications network to PG&E, PG&E estimates that leasing an AMI meter infrastructure could cost up to 20 percent more than conventional ownership and financing.
- Analysis of the costs and benefits of AMI for customers over 200 kW. PG&E omitted analysis of this group of customers on October 15 since most of these customers already have advanced (interval) meters. Thus the benefits of demand response from dynamic rates are already largely attainable for this group without installing new metering. PG&E further notes that on December 8, 2004 the Assigned Commissioner issued a new ruling requiring that utilities install interval meters for the remainder of this group and that these customers be placed on default critical peak pricing (CPP) rates by summer 2005. Nevertheless, PG&E believes there may be value to including large customers in AMI and is continuing to evaluate the costs and benefits of integration. In addition, irrespective of the question of whether such benefits should be included as part of the AMI business case, PG&E complies with the November 24 ACR by

providing below an analysis of potential demand response benefits for large customers from dynamic rates (including Real Time Pricing (RTP) rates). PG&E has used a similar approach for this purpose to that used by Southern California Edison (SCE) for the estimates that it included as part of its preliminary business case showing.

- Description of factors involved with AMI technology choice. PG&E has not selected its AMI technology or combination of technologies: PG&E is currently involved in an intense process to evaluate the bids received in response to its AMI RFP. PG&E does, however, provide below a general discussion of the types of AMI technologies available.

I. ANALYSIS OF OUTSOURCING FUNDING AND IMPLEMENTATION APPROACHES

A. July 21 ACR Outsourcing Requirements

The July 21 ACR stated (Attachment A, p. 4):

> Two different financing/implementation approaches should be analyzed . . . : (1) internal financing/implementation and (2) outsourcing. In the internal financing/implementation analysis, costs of AMI acquisition and installation are considered conventional assets owned by the utility and included in rate base with ongoing operation and maintenance provided in-house or by third parties. In the outsourcing analysis, AMI acquisition, installation, and operations and maintenance are obtained under contract, through leasing agreements, limited partnerships or other business arrangements with third party providers. Contractual arrangements determine the tax implications and whether the AMI asset and related implementation costs are rate based or treated as an operating expense.

As PG&E explained in its October 15, 2004 filing (p. 12, footnotes omitted):

> The Ruling directs that the utilities consider outsourcing of implementation and financing in their analyses. PG&E has incorporated this directive to the extent possible. First, PG&E's meter installation analysis assumes that non-PG&E labor will perform that function. However, PG&E's analysis assumes PG&E will perform operation and maintenance (O&M) of the AMI system after installation. Second, with respect to outsourced financing, PG&E has not yet chosen a technology path or a vendor for AMI. PG&E's acquisition strategy, deployment strategy, and resulting cost information are therefore not sufficiently refined for this purpose and a single set of costs is used in this filing. PG&E's analysis of bid responses from the RFP process will enable PG&E to assess contracting options and the cost difference between utility ownership and outsourcing – if there is any.

B. Responses To PG&E's RFP Signal The Unattractiveness Of Outsourced Financing For Meter Assets

No responses to PG&E's AMI RFP contained an outsourcing proposal for meter ownership.[2] This confirms PG&E's view that it will likely be more efficient for the utility to own and finance the assets.

As PG&E stated in its October 15 filing: "leasing arrangements (one type of outsourced financing option) are traditionally an unattractive source of financing for PG&E due to the additional costs associated with leasing compared with conventional secured debt financing and because many of the traditional benefits of leasing are not applicable to PG&E."

Leases are fixed financial obligations incurred in order to obtain the use of an asset without actually holding title to that asset. The economic substance of leases is that

[2] There are examples from the mid-90's of other utilities in the United States that have deployed advanced metering using outsourced AMI contracts. However, PG&E is unaware of any outsourced AMI ownership contracts since 1999. Presumably this reflects both the utilities' and the vendors' lack of interest in outsourcing as a feasible option.

they are asset financing arrangements. This holds irrespective of their treatment for financial reporting purposes, whether capitalized as on-balance sheet obligations or off-balance-sheet operating contracts. Because they entail fixed future cash outflows, they are treated as debt obligations by credit rating agencies and other creditors. A credit analyst will typically treat the present value of future minimum lease payments as 100% equivalent to a direct debt obligation of a borrower. Accordingly, the correct economic analysis of a lease compares the lease payments with the borrower's conventional cost of debt, not a weighted average cost of debt and equity capital analogous to the rate of return on rate base.

Lease financing is expected to offer an expensive alternative to traditional utility debt financing. Although leases may offer lower up-front cash outflows by providing 100% financing, they are generally more expensive over the long run given the need to compensate the lessor for the use of its assets, asset depreciation, and borrowing costs which are almost certainly higher than PG&E's.

Given PG&E's "BBB" senior secured rating, lenders are unlikely to offer terms that are better than what PG&E could secure through its own conventional borrowing. A lease will be treated as a "100% debt equivalent" with the ratings agencies, displacing lower cost conventional debt. If PG&E were to lease the AMI assets, the company would have to increase the proportion of common equity in its rate base capital structure in order to maintain a balanced capital structure for credit rating purposes. Leasing would therefore simply increase PG&E's borrowing costs and potentially expose customers to higher rates.

Moreover, AMI equipment is not conducive to leasing. Unlike the leasing of most conventional assets (such as autos) AMI hardware does not lend itself to lease financing given the specialized function of the equipment and the strategic role this infrastructure is expected to play in PG&E's daily operations. AMI hardware and software will be tailored to PG&E's technical requirements, and unlike assets such as autos or real estate, its value will not be easily transferable (i.e., since it's value is greatest to PG&E, AMI equipment is not suited to serving as collateral which can be re-sold to a third party). If a lessor was required to provide financing, the charge would be high to compensate for the high technology risk (depreciation/ obsolescence) and low re-sale value for the equipment.

Furthermore, AMI equipment is expected to serve as a critical contact point between PG&E and its customers. The lack of control/ownership of the assets could expose PG&E to significant customer satisfaction issues if there are disputes with the vendor (or other business failures stemming from the vendor managing the AMI equipment) resulting in an interruption of service. Outsourcing the ownership of AMI equipment could also involve high barriers to exit (e.g. once installed, and assuming a 15 to 20 year useful life, the vendor could enjoy a high level of negotiating leverage versus PG&E in future business discussions).

Outsourcing also exposes the utility to the financial stability of the vendor: There are cases where utilities entered into lease arrangements with vendors who subsequently entered bankruptcy. After the discharge of the bankruptcy and the acquisition of the assets by a third party, the acquiring party entered into discussions with the utilities to increase the prices. This type of instability and heightened risk for PG&E and its customers is a factor that must be considered when evaluating the lease financing option.

Even if AMI assets were suitable for leasing, PG&E is unable to benefit from many of the traditional advantages of leasing. For example, many leases are structured to transfer accelerated tax depreciation benefits from a company which has a low marginal tax rate to a leasing company with a high marginal tax rate. As a net taxpayer, PG&E can use 100% of its tax benefits from interest payments and depreciation. However, one tax advantage that may be possible is where a lessor is able to depreciate the assets more rapidly than PG&E, and to reflect that benefit in lease payments. If such a benefit exists PG&E would need to determine if the benefit was sufficient to offset the drawbacks of leasing.

PG&E remains open to the possibility that a vendor could propose leasing terms or a performance-based operating contract that could provide economic benefits to ratepayers. However, based on economic logic, the nature of the assets, and the company's experience, this would appear to be highly unlikely. Moreover, the limited data that vendors provided regarding outsourcing supports this expectation.

C. PG&E's Preliminary Analysis Shows That Lease Financing Would Be Substantially More Costly Than Conventional Financing

PG&E received no offers to provide an overall outsourced ownership solution for AMI metering equipment in either the Request for Information process in the spring of 2004 or the September 27 RFP. However, one of the bidders out of the 48 vendors responding to the RFP proposed to outsource the ownership, maintenance and operation of certain components for the network elements only (excluding meters or IT infrastructure) of the AMI system.

PG&E has not completed the process of evaluating this proposal for reasonableness of the services, the price, or the longevity/viability of the entity making the bid. However, this bid represents the only data point PG&E can use to benchmark the internal cost of owning and operating the system against the cost from an outsourced perspective.

Based on preliminary analysis of this bid, the outsourced cost could represent up to a 20 percent premium over PG&E owning and maintaining the network and would therefore appear to raise the cost of AMI deployment significantly.[3]

II. COSTS AND BENEFITS OF AMI FOR CUSTOMERS WITH DEMANDS GREATER THAN 200 KW

A. July 21 ACR Requirements For Customers Over 200 kW

The July 21 ACR requested that the utilities assume that by 2008: "All large commercial and industrial customers (> 200 kW) [will be on] two part real time tariffs; customers may elect to switch to their currently applicable TOU tariff. . . .Two part real time tariffs include a baseline load shape where customers are charged their current tariff for their baseline usage but a marginal (real) price for increases above the baseline." Attachment A, p. 11.

In its October 15, 2004 filing, PG&E explained that it was excluding customers over 200 kW from its preliminary AMI analysis both from a costing standpoint and a benefits standpoint since most customers over 200 kW already have advanced meters (many of which were funded under AB 29X). PG&E pointed out that in an Assigned Commissioner's Ruling dated November 24, 2003, the Commission deferred the issue of providing the remaining customers in this group with interval meters.

Recently, on December 8, 2004 the Assigned Commissioner issued a ruling in this

[3] PG&E will provide upon request workpapers explaining how it arrived at this estimate to regulatory staff and to parties that have executed PG&E's AMI non-disclosure agreement.

docket directing the utilities to move immediately to supply interval meters to the remaining customers above 200 kW and that all customers above 200 kW should be moved onto default CPP rates by summer 2005. (December 8 ACR).

PG&E will continue to evaluate the costs and benefits of integrating large customer metering with AMI and provide an update in future filings. PG&E has also performed additional analysis of the benefits of dynamic rates (which could include RTP rates) for this customer group as explained below.

B. Supplemental Analysis Of Costs and Savings Of AMI for Customers Over 200 kW

1. PG&E's Above 200 kW Customer Group

Please refer to Tables 1 and 2 (attached) for a summary of PG&E's current population of customers with at least 200 kilowatts (kW) of demand.[4] As shown in Table 1, PG&E currently provides service to approximately 8,700 customers with demands at this level or above. However, approximately 1,300 of these customers currently receive direct access, and so are subject to interval metering protocols applicable to direct access. Of the approximately 7,400 bundled service customers with at least 200 kW of demand, approximately 5,700 are already interval-metered. All of these meters are read remotely using either telephone modems or radio-frequency communications, the former using a system operated entirely within PG&E, and the latter using contracted services from an external vendor. All of these meters are read daily, at either a 5 or 15 minute interval resolution. Customer accounts in the >200 kW group who have an interval meter are currently billed on a time-of-use tariff, participate in a demand response program, or

[4] For purposes of this analysis, PG&E defines customers having at least 200 kW of demand as customers who have had an average billing demand of at least 200 kW per month over the last 12 months.

both. This leaves approximately 1,700 customers with at least 200 kW of demand who have not yet received interval meters. However, as a group, PG&E estimates that these last 1,700 customers account for less than 10 percent of total electric consumption in the above 200 kW customer category.

The existing infrastructure provides customer data, in hourly increments, via PG&E's InterAct II website, on a "day after" basis. This web application provides customers with detailed information on their electric usage, including sophisticated tools to enable load profiling, account aggregation, display of hourly local weather conditions, and hourly wholesale electric pricing data. The application also supports customer notification of and response to load curtailment events, including submission of load reduction bids for event participation and the calculation of program incentives, where applicable.

2. RTP Benefits (Or Any Dynamic Rate Benefits) Are Not AMI Benefits For Most Customers Over 200 kW Since They Are Largely Attainable Under Existing Metering; Nonetheless, PG&E Submits An Estimate Here For Such Benefits In Order To Comply With The November 24 ACR

In its October 15 submission, PG&E did not include the >200 kW meters and systems as a separate group in the AMI business case, but rather considered them embedded as part of the base case assumption. Since most of these accounts are already equipped with real time meters, no incremental costs or incremental savings were anticipated in the business case. Even "filling out" the remaining 1,700 meter installations for this customer category, as contemplated in the December 8 ACR, would not qualify as incremental costs or savings for the business case if different metering technology and communications systems are used for customers of this size. However, as noted previously PG&E is currently assessing the benefits of integrating large customer meters with AMI.

Setting aside the question of whether dynamic pricing load reduction benefits for large customers should be included as part of the AMI business case, PG&E complies with the November 24 ACR by providing a new analysis here for potential dynamic pricing load reductions that might be contributed by large customers under future RTP programs. PG&E has used a similar approach for this purpose to the approach that was used by SCE for the dynamic pricing demand reduction estimates that SCE submitted as part of its own preliminary business case showing (filed in this docket on October 22, 2004). Both SCE and PG&E have relied in large part on a January 14, 2004, Christensen Associates study titled "Potential Impacts of Real-Time Pricing in California" for the purpose of preparing these estimates.

The results of PG&E's analysis are summarized in Tables 2 and 3 (attached), which show estimated demand reductions of approximately 300 MW as possibly being achieved through new dynamic pricing programs that might be developed for the approximately 4,000 MW of total bundled service load of the over 200 kW customers.[5] PG&E excludes direct access customer loads from this analysis, under the assumption that dynamic pricing programs for such customers (if any) would most appropriately be offered by their own direct access service providers. After excluding direct access loads, PG&E uses the same methodology that was used in the SCE preliminary business case filing to estimate dynamic load reduction potential from these customers, based on the composition of the large customer population served by PG&E. Depending on how these

[5] PG&E assumes that these 300 MW would be realized through some combination of future dynamic pricing tariffs, presumably including a combination of both Real-Time and Critical Peak Pricing. The January 2004 Christensen Associates study does not describe specific tariffs or prices.

rates interact with existing programs, this may or may not be incremental demand reduction to existing demand response from these customers.[6]

If future dynamic pricing programs for the large customer population produced 300 MW of new load reductions, this would represent capacity savings of approximately $25 million per year at the $85/kW-year avoided capacity cost level specified in the July 21 ACR.

3. Possible Additional Benefits of AMI For Customers Over 200 kW Involve Data Collection And Communications (Backhaul) Savings

PG&E is continuing to review any potential operational savings in the areas of metering and data acquisition that might be applicable to this group resulting from an AMI deployment. Specifically, data acquisition (back-haul) utilizing a PG&E-owned and operated network infrastructure, such as a fixed radio network or power line carrier, may offer reduced costs compared to the private radio and public telephone networks in use today. Likewise, there may be potential for savings in the area of interval meters and associated hardware, and/or back-office system processing, in either a partial or full AMI deployment. PG&E is currently reviewing the bids submitted by vendors in response to PG&E's September 27, 2004 RFP. At this point, it is too early in the review process to cite any potential for or definitive estimate of incremental savings for large customers. PG&E will address this issue further in future filings.

---

[6] However, Table 2 shows that only approximately 6 percent of PG&E's current bundled service load in the large customer category is supplied to non-firm rate customers, so by far the largest part of the 300 MW load reduction estimate developed in Table 3 would be attributable to current firm service customers.

III. METER NETWORK FUNCTIONALITY ANALYSIS AND TRADEOFF DISCUSSION

A. Current Status of PG&E's AMI Technology Choice

The November 24 ACR stated that some utilities did not "include a description of the functionality of meter and network systems they analyzed and discuss the tradeoffs they made to reach their decision on meter and network functionality."

On October 15, PG&E explained its approach to technology choice for purposes of preliminary analysis:

> There are several AMI technologies capable of meeting the requirements outlined in the July 21 ACR. In selecting a combination of technologies for its preliminary analysis, PG&E considered costs and whether the technology has been deployed successfully on a commercial scale. Specific detailed costs that may be required for other types of technology or system interfaces are therefore not estimated. PG&E stresses that these working assumptions do not imply that the technologies assumed in this preliminary business case will ultimately be chosen. They were used in the business case only because specific technologies must be assumed for the sole purpose of developing a preliminary cost estimate. The assumptions used in this filing should not prejudge what technology PG&E may ultimately recommend after reviewing the results of its RFP. PG&E's technology choice assumptions are shown in Appendix B.

PG&E has still not made any decisions about what AMI technology, or combination of technologies it will use. Numerous factors will play into the decision. At a minimum PG&E's AMI technology will be capable of the Commission's functionality requirements referenced in the July 21 ACR. In addition, numerous other factors will determine the ultimate choice. As was stated in the RFP: "PG&E will evaluate the merits of each Supplier's proposal with regard to price, functionality, performance, vendor maturity, business terms, product maturity, schedule and overall risk."

Now is an especially critical time in PG&E's process of selecting vendors and negotiation of contracts. Accordingly, to ensure that PG&E has the opportunity to negotiate aggressively, it would be inappropriate for PG&E to reveal any further detail about its bid selection process. However, in the spirit of complying with the Commission's request for a discussion of AMI technology, PG&E provides the following generic discussion.

B. General Description Of Available AMI Technologies

1. Overall Structure of an AMI System

An AMI deployment includes four main functional elements. Each functional element is a system or a set of services connected to a system. These elements are described briefly below. PG&E divided its September 27 RFP along these functions and sought separate bids on each functional area.[7]

AMI System: All of the meter equipment, software, communications networks and connectivity, implementation support, training, documentation and other services required to supply a fully functioning AMI System. This includes the provision of "installation ready" new and/or refurbished meters and AMI modules, the AMI communication network modules, and the AMI System Controller. The heart of the AMI System is the AMI System Controller that provides three critical functions: the management of all communications between users and end devices such as meters; the management of the communication system itself to ensure its reliable operation; and the processing and storage of raw data.

[7] Further, PG&E is also seeking a load control solution as an additional element of its RFP.

AMI Interface System: All of the equipment, software, communications connectivity, implementation support, training, documentation and other services required to supply a fully functioning AMI Interface System. The AMI Interface System takes the raw data from the AMI System Controller and prepares it for use by other utility systems such as billing and outage management.

The AMI Interface System is the software that will perform the data "framing" function to translate the interval meter readings into billing determinants. No other utility has implemented dynamic pricing for billing purposes on the scale and volume contemplated by the Commission (i.e., default dynamic rates for all customers). As a result significant advance development work and testing will be necessary to validate scalability and operational capability of these systems.

Installation Services: All of the equipment, software, labor, management and other services and resources required to (i) install new and refurbished electric meters, (ii) retrofit gas meter modules and install new gas meters, and (iii) install local network equipment (repeaters, concentrators, etc.).

Project Management and Systems Integration: The provision of overall project management and systems integration services and support to achieve the successful deployment of PG&E's selected AMI solution, including managing the implementation of all of the products and services covered by the other functional areas. This may include the provision of IT integration and project management support to integrate AMI functionality with PG&E's existing billing, outage management, SAP and related systems.

2. Types of AMI Systems and Networks

Below, PG&E further expands on the technology and certain functional capabilities of these systems.

a. Meter Modules

Most AMI meters or meter modules included in customer meters have similar capabilities, but there are differences. For example:

- Battery lives and replacement costs for modules may be different across vendors, resulting in a significant impact on life cycle costs.
- Some modules store hourly data and transmit that data once or several times per day. Other modules transmit at least hourly, but store no historical data at all.
- Some modules track time, while others simply transmit the consumption data and count on the network receiving the data to keep track of the time.

Careful business case analysis can reduce the differences in features to differences in costs and performance.

b. Communications Architecture

The four major AMI system communication architectures include:

Mobile Systems: Mobile systems rely on a van driven throughout the service area. The van uses a short-range radio to collect data from meter modules.

Hierarchical Wireless Networks: In hierarchical networks, meters communicate with repeaters that in turn communicate with concentrators that then use public wireless networks or telephone lines (Wide Area Network, or WAN) to pass messages to/from the central information hub. These networks can have from 2 to 10 or more communication layers.

Star Networks: Meters in star networks report directly to an access point where public wireless or public telephone access (WAN) exists to communicate back to the central information hub. Star networks can use radio or power line carrier communications.

Mesh Networks: In mesh networks, electric meters or load control devices communicate with each other in a self-organization process to establish a path to a concentrator that has a WAN link to the central information hub. Gas meters as well as water meters may communicate via the electric meters in order to communicate with the AMI System Controller.

c. One-Way vs. Two-Way Communications

Communications between the meters and load control devices and the central information hub can be "one-way" or "two-way." Information flows only from the meters to the central information hub in AMI systems with a one-way "multipoint-to-point" architecture, while information flows only from the central information hub to the meter premises in load control systems with one-way "point-to-multipoint" architecture. Two-way systems support the flow of information both ways between the center information hub and the customer premises. Two one-way systems (point-to-multipoint plus multipoint-to-point) are not necessarily equivalent to a single two-way system because of gaps in functionality, geographic coverage and other factors. Further the cost of two one-way systems may be lesser or greater than the cost of a single two-way system. The desirability of a one way or a two-way system will depend on a variety of factors.

One-way and two-way AMI systems each perform the task of collecting regular monthly meter readings from customers. In one-way systems, the meters broadcast readings on a frequent basis, and the central information hub simply listens carefully to capture the needed information. In two-way systems, the central information hub queries each meter when information is required, and captures the information when the individual meters respond.

3. Basic Functionality Provided By All Technologies

All technologies being considered by PG&E support a wide variety of potential rate structures and customer service options. All can provide the following:

- Remote meter reading;
- Price responsive tariffs;
- Collection and distribution of interval usage data to improve customer understanding of usage and energy costs; and
- Interfacing to a load control system.

4. Advanced Features

Some of the AMI systems under consideration can provide various additional advanced features including:

- Load research data;
- Power outage event information;
- Load control device operational data;
- Feeder voltage monitoring data.

* * *

Perhaps the biggest difference among the various systems is not related specifically to the technical design and features of the solution, but to vendor stability and expertise and product maturity, i.e., the likelihood that the vendor will be able to deliver a system or service that meets the contract terms. PG&E's strategy for minimizing risk will be to choose vendors who have a successful track record in providing AMI solutions to utilities. Further, PG&E plans to employ an aggressive acceptance test program to minimize performance risk.

CONCLUSION

PG&E respectfully submits that the preceding discussion supplements PG&E's October 15, 2004 preliminary AMI business case filing in accordance with the November 24, 2004 ACR. These and other issues will also be addressed further in future filings.

Respectfully Submitted,

LINDA L. AGERTER
PETER OUBORG

By:____
PETER OUBORG

Pacific Gas and Electric Company
P.O. Box 7442
San Francisco, CA 94120
Telephone: (415) 973-2286
Facsimile: (415) 973-5520
E-Mail: pxo2@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: January 12, 2005

TABLE OF CONTENTS

Page

CERTIFICATE OF SERVICE BY MAIL

I, the undersigned, state that I am a citizen of the United States and am employed in the City and County of San Francisco; that I am over the age of eighteen (18) years and not a party to the within cause; and that my business address is Pacific Gas and Electric Company, B8R, PO Box 770000, San Francisco, CA 94177.

I am readily familiar with the electronic service protocols set forth in Appendix A attached to the Order Instituting Rulemaking issued June 6, 2002 in Docket R.02-06-001.

On January 12, 2005, I served a true copy of:

SUPPLEMENTAL PRELIMINARY BUSINESS CASE FILING OF PACIFIC GAS AND ELECTRIC COMPANY

by electronic transmission to all parties on the official service list r.02-06-001 who provided e-mail addresses.

I certify and declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct and that this declaration was executed on January 12, 2005, at San Francisco, California.

KAREN THERESA ABALOS

January 12, 2005

VIA HAND DELIVERY

Docket Office
State of California Public Utilities Commission
505 Van Ness Avenue, Room 2001
San Francisco, CA 94102

Re: Pacific Gas and Electric Company
Rulemaking 02-06-001

Dear Sir/Madam:

Enclosed for filing are an original and five copies of SUPPLEMENTAL PRELIMINARY BUSINESS CASE FILING OF PACIFIC GAS AND ELECTRIC COMPANY. Please place a file-stamped copy of this filing in the PG&E box for pick up. Thank you.

Very truly yours,

Peter Ouborg

PO:ka

Enclosures

cc: CPUC Commissioner Michael R. Peevey
CEC Commissioner Art Rosenfeld
ALJ Michelle Cooke
Julie Fitch
Moises Chavez
Bruce Kaneshiro
Michael R. Jaske
Mike Messenger
Service List