PROPOSED PILOT PROJECTS AND MARKET RESEARCH TO ASSESS THE POTENTIAL FOR DEPLOYMENT OF DYNAMIC TARIFFS FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS

Report of Working Group 3 to Working Group 1
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SECTION 1 - INTRODUCTION

1.1 Introduction and Summary

Working Group 3 (WG3) has completed its review of current experience with dynamic tariffs.[1] Based on this review, most of the participants in WG3 propose to conduct market research and pilot tests to gather the remaining data necessary to make a decision on the full-scale deployment of dynamic tariffs and interval meters in calendar year 2003. This design integrates several of the pilot concepts proposed by WG3 members over the last two months. The three investor-owned utilities propose to conduct market research to refine the dynamic rate and control technologies to be tested and then to implement a statewide pricing pilot (SPP) to test time-of-use (TOU) and critical peak pricing (CPP) tariffs for a representative sample of residential and small commercial customers on an opt-out basis. Most of the WG3 participants support the adoption of the SPP as is, or with minor modifications (See Appendix A). Supporters include Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), the California Energy Commission (CEC), the Office of Ratepayer Advocates (ORA), California Utility Employees (CUE), The Utility Reform Network (TURN), the San Francisco Community Power Cooperative (SFCPC), the California Consumer Empowerment Alliance (CCEA), Consumers Union (CU), Siemens, and Distribution Control Systems, Inc. (DCSI).

Individual WG3 members also seek adoption of alternative or complementary pilots that are compared to the SPP proposal in **Table 1-1**. Invensys (a meter service provider) proposes an alternative pilot to test the effectiveness of an advanced interactive technology treatment and dispatchable demand response offerings. IMServ proposes a pilot to test the concept of providing customers with cash incentives (based on T&D savings) for a combined integrated demand response/enabling technology and advanced metering open architecture solution directed towards reducing demand on constrained transmission and distribution circuits.

[1] A glossary of electricity rate terms used in this report is provided at the end of this section.

Table 1-1. Summary of Pilot Proposals

Proposal Name & Sponsor	Dynamic Rates to be Tested	Targeted Population and Sample Size	Equipment to be Installed	Proposed Budget
Statewide Pricing Pilot or SPP (Utilities, CEC, SFCPC, others)	2-period TOU, fixed CPP, variable CPP	1,520 residential 540 small commercial	Interval meter, enabling technology for some customers	$9.6 million
Home Control Alternative (Invensys)	None. (Pay for performance)	3,000 residential	Interval meter, gateway, smart thermostat	$5.5 - 7.5 million
T&D Control Pilot (IMServ)	None. (Pay for performance)	1,000 small commercial	Interval meter, gateway	$2 million

The pilots in Table 1 were developed to try and meet Policy Working Group's goal of gathering additional information on the potential to increase demand response from these customers by developing and deploying dynamic tariffs to a small but representative sample of customers. To some extent the research objectives of the Invensys and IMServ pilots may be duplicative of objectives of the SPP.

The SPP will gather data on customer acceptance of various tariff forms and expected changes in customer demand as a function of changing prices, control technologies, and customer information. If all goes well, interim results from the first three months of these tests can be used in September 2003 to begin to assess the cost effectiveness of rolling out dynamic tariffs to some or all customers in the residential and small commercial classes in 2005. Details on the policy, costs, and accuracy tradeoffs involved in making these design choices are included in the body of this report.

1.2 Procedural History

The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) adopted an Order Instituting Rulemaking in July 2002 designed to develop additional demand flexibility or response to increase system reliability, reduce power purchase and individual consumer cost, and protect the environment. The CPUC decided to use a working group process to develop specific tariff and program proposals to achieve increased demand response in the state. This report contains the initial recommendation of one of the three working groups formed to achieve these goals. The mission of WG3 was to seek to expand the demand response capabilities of the current electricity market by developing a tariff or set of tariffs that can be pilot tested for residential and small commercial customers with demands under 200 kW.

Working Group 1 asked WG3 to complete the following tasks:

1. Review the current literature and field experience to identify where significant information gaps exist with respect to customer experience and response to dynamic tariffs or demand response programs.

2. Recommend a strategy to fill these gaps including but not limited to: additional market research, modifications to existing pilots of dynamic tariffs, or the design of new pilots to test dynamic tariffs

3. Propose an implementation plan and schedule to fill the gaps

4. Describe how the results from the pilots will be used to conduct further analysis in Phase 2, which is designed to assess whether these new dynamic tariffs and the infrastructure to support them are cost effective to both participating customers and all ratepayers.

In subsequent rulings, the Policy Working Group (Working Group 1 or WG1) expressed a preference for the design of pilots that would provide the maximum amount of information on how different types of customers respond to different dynamic tariffs and to ensure that customer's had the option to opt out of any pilot test of new tariffs. These topics are addressed in Section 3, which describes the proposed market research and pilots.

This report is organized into seven sections that address these topics.

1. Introduction

2. Information Already Known about Dynamic Tariffs and Price Response

3. Pilot Proposals and Market Research

4. Discussion of the Results of PG&E's Preliminary Business Case Analysis

5. Plan To Evaluate and Link Results from the Pilot to Future Cost Effectiveness Analysis

6. Proposed Cost Recovery Mechanisms

7. Metering and Technology Systems for Small Customers (below 200 kW)

1.3 What is Known About Small Customer Experience with Dynamic Tariffs

The group compiled a database[2] of over 50 previous studies of time of use and dynamic tariff programs and synthesized the following key findings from these studies:

1. Studies have found that small electricity consumers – on average – respond to time-varying prices by reducing usage during expensive time periods and shifting it to inexpensive periods. Price elasticities ranged from -0.82 for high critical peak prices for residential customers to -0.03 for time of use prices for small commercial customers.

2. The level or magnitude of demand response to higher prices varies by class (residential vs. small commercial), usage level, appliance holdings, climate, presence or absence of automated control capability, and program duration. Only one study from Pennsylvania has been completed to measure the elasticity of critical peak prices that are dispatched on a day-ahead basis to small customers. This study, of residential customers only, found an elasticity of -0.35.

3. The literature shows that price responsiveness by small commercial customers is substantially smaller than residential responsiveness. However, given the larger loads of such customers, it is possible that some subgroups (e.g., those between 20 and 200 kW) may have benefits sufficient to offset the incremental cost of metering. In addition, no dynamic pricing programs have been conducted for small commercial customers. These reasons warrant including these customers in the proposed pilot program as well.

Important information gaps remain and are summarized below:

1. What will be the specific level of demand response, or price elasticity, for residential and small commercial customers in California's current energy situation in response to time of use and or critical peak prices? How will these responses vary across a range of household energy usage levels, appliance holdings, climate zones and awareness of local environmental and reliability conditions; for critical peak pricing with and without automated control capability?[3]

2. What are California customer preferences for critical peak pricing implemented via a voluntary opt-out approach, and what information do customers need to ensure that they are fully informed?[4]

3. As a result of the answers to the above two questions, are there specific customer segments where dynamic pricing makes sense and other segments where it does not?

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[2] The database is available as an Appendix to the report.
[3] Critical peak pricing has been tested before only with automated control capability
[4] Voluntary opt-out approaches have been tested before only with time-of-use pricing, not critical peak pricing

These gaps can be filled by implementing the market research and pilot program as described below and in Section 3.

1.4 Providing this Information through Market Research and Pilot Tests

WG3 has designed a plan that consists of preliminary market research in early to mid-2003, deployment of the to the selected sample in the first half of 2003, and analysis of the results during 2003 and 2004. The primary objective of the market research phase is to determine customer preferences for different forms of dynamic pricing, information treatments and control technologies within a focus group setting to ensure customers will not be exposed to technologies or dynamic rates they cannot understand or effectively use. The goal of the focus groups is to identify the most acceptable rates and control technologies from the customer perspective and thus refine the number of new dynamic rates and or technology treatments that will be tested in the statewide pilot.

The primary research objectives of the statewide pilot are to:

1. Estimate expected short term demand elasticities for key customer segments in response to being exposed to three types of time varying and dynamic rates: time of use (TOU), fixed critical peak pricing (CPP-F), and variable critical peak pricing (CPP-V).

2. Develop demand curves that will allow utilities to generalize the results from the pilot to estimate the expected level of demand response that could be expected if all or some of the residential and small commercial customer class were offered the option of using dynamic tariffs.

3. Gather information on customer acceptance and opt out rates for different forms of dynamic rates, control technologies and information treatments.

The SPP is designed to measure the impact of three specific time-varying rates on customer electric consumption and coincident peak demand: (1) TOU rates, (2) CPP-F rates, and (3) CPP-V rates (CPP-V). TOU rates feature higher prices when the costs of providing electricity is typically higher, using one or two peak periods per day, and lower prices during off-peak periods. CPP-F rates resemble a standard TOU rate on most days of the year, and includes a fixed higher rate during ten to fifteen days of the year when wholesale prices are high due to congestion or reliability problems. The higher CPP rate applies to the hours that would otherwise have constituted the highest price period in the TOU rate. CPP-V rates differ from CPP-F rates in that the critical peak period may be called at any hour on the day-of high prices (hence variable term) and it is not confined to a fixed number of hours that are known in advance. On the other hand, customers must receive a day-ahead notification for all CPP-F rate days.

The proposed sampling plan includes the assumption that 20% of the customers will choose to opt out, leading to the need to recruit a gross sample of 2,575 customers across six segments to yield a net sample of 2,060 customers. Four of the six segments are in the residential sector, and are designed to capture the variation in customer price response across the state's four major climate zones. Two of the segments are in the commercial sector, and differ in size.

The total net sample includes 1,500 residential homes and 560 small commercial customers. Of these, about 1,500 will be selected through a stratified random sample on a statewide basis, and are designed to provide statewide price elasticity estimates for TOU rates and CPP-F and CPP-V rates. Another 200 will be selected through a stratified random sample in the San Francisco area, and are designed to measure the effects on demand response of increased awareness of local environmental and reliability issues. Finally, 360 small commercial customers will be selected from the existing population of customers who have opted into the AB 970 program featuring smart thermostats.

In addition, to distinguish responsiveness between large and small residential consumers, customer size will be included as a right-hand-side, interaction variable in the modeling phase of the analysis. Consideration will also be given to stratifying by size in the sample plan (e.g., over sampling larger consumers), so as to ensure that there will be sufficient representation of larger customers in the sample.

The SPP will require funding of $7 million to install the meters and equipment and $2.5 million to perform the market research, manage the project and evaluate the load impact. In Section 3, Charles River Associates (CRA) estimates that the value of conducting the pilot is likely to exceed $225 million based on the expected reduction in the uncertainty of the net benefits from introducing dynamic tariffs resulting from the pilot. Thus the cost of the pilot is roughly 1/20 of its expected benefits. The group has also provided information on the expected benefits and costs from the pilot sample alone in Section 3.1.5. Information on the proposed method of cost recovery is presented in Section 6 of this report.

The market research and pilot tests are expected to produce the following information:

1. Estimates of customer understanding and acceptance of the following types of tariffs: time of use, time of use rates with CPP signal for 50 to 100 hours per year, inverted rate structures (current rates), and a flat rate with fixed monthly hedge.

2. Demand functions (e.g. the expected change in hourly energy usage as a function of the change in price) as a function of the following variables:

    a) weather
    b) customer peak usage
    c) control technologies used
    d) Information or energy use feedback presented to customers

Customer acceptance results will be available by mid-summer 2003 and interim elasticity results will be available in the fall of 2003. The goal is to obtain decision quality data by the end of 2003. However, the pilot may continue past 2003 to allow refinements in the estimation of price elasticities.

These results will be used to perform the following analysis tasks in Phase 2.

1. Estimate the anticipated changes in household and system wide peak demand that would result from the introduction of a mix of dynamic tariffs in 2005.

2. Estimate the cost effectiveness of introducing dynamic tariffs and the infrastructure to support them as part of the business case to specific sets or all customer groups.

1.5 Preliminary Business Case Findings

In advance of these proceedings, Pacific Gas and Electric (PG&E) and Charles River Associates (CRA) completed a preliminary business case study including a cost-benefit analysis associated from deploying advanced metering and implementing various forms of TOU and dynamic pricing options. PG&E shared the results their cost-benefit analysis at the October 31, 2002 Working Group 3 (WG3) meeting. Additional details of their assumptions, analysis and findings are located in Section 5 of this report.

The key findings of their analysis were threefold. First, their analysis determined that the benefits of introducing dynamic rates and thus more demand response were highly uncertain and ranged from $561 million to $2.637 million. Second, reducing the uncertainty in the anticipated level of demand response is critical because the business case identified a financial gap of approximately $1,080 million (pre-tax, $640 million after-tax) over a 15-year study period that must be bridged by the demand response benefits to make the investment cost effective. This gap was quantified by taking into consideration the implementation costs as well as the anticipated utility operational benefits associated with universally rolling out an advanced metering system. Thirdly, for each utility, the actual deployment costs and resulting benefits will be different. Therefore, each utility must explore these costs and benefits more fully in Phase II of this proceeding. The development of analysis quality costs will need to be supported by a thorough Request for Proposal (RFP) process conducted by each utility with advanced metering technology suppliers. A robust cost/benefit analysis of advanced metering system deployment and dynamic pricing can then be made based on the improved information gained through the recommended statewide pricing pilot coupled with each utility's specific advanced meter system deployment costs and resulting operational benefits.

1.6 Infrastructure Needed to Support Dynamic Tariffs

There are a wide variety of meters and network configurations that can be used to support various forms of dynamic tariffs. Section 7 describes these choices and identifies the key functional differences between different networks and their ability to support different tariffs. This appendix also presents information on the range of costs to install and operate these systems for a range of tariffs ranging from simple time of use to complex hourly tariffs that in some cases require two way communication between meters and utility billing centers. The key variables affecting future system deployment costs are:

a) Fraction of customers who choose dynamic tariffs and expected turnover rates

b) Meter density - costs are lower in urban, high density areas

c) Meter function - billing only or messaging system for demand response signals

d) Assumed linkage from meter to various types of automated control technologies

1.7 Importance of Getting Field Trials Started by June 1, 2003

The Policy Working Group has informed Working Groups 2 and 3 that they placed a high priority on deploying some form of dynamic tariffs before the summer of 2003. WG3 has attempted to respond to this direction by producing a very compressed schedule that requires market research to begin in the beginning of 2003 before the final sample design is set. WG3 requests that the CPUC consider authorizing immediate establishment of a regulatory account by each utility to record up to $1 million (total for all three utilities) of expenditures over the next two months to conduct the limited market research described in Section 3, and the costs of other prudent advance activities necessary to try and ensure the SPP can be implemented by June 2003. . This early decision is needed to ensure that the market research, and pilot design refinement and sample design, can be finished in time to allow the utilities to order and install the necessary meter infrastructure to support the pilot test starting in mid-February of 2003 and finish before June 1, 2003 when the pilot is scheduled to begin.

1.8 Implementation Process

WG3 proposes to form an advisory committee composed of representatives from WG3 and the CPUC's Energy Division to provide advice to the utility project managers on the implementation of the pilot project. Utilities will make the final decisions related to rate treatments, technology treatments and the types of information to be made available to customers consistent with the advice provided by the committee. The group will meet once a month and provide quarterly status reports on the progress of the pilot project to the CPUC.

1.9 Summary of Requests for Commission action

WG3 requests following Commission actions:

1. Authorize spending up to a cap of $10 million to conduct the statewide pilot test of dynamic tariffs. The estimated cost of the SPP is $9,590 million but this may change as a result of information gathered during the market research phase, or if other key assumptions fail to hold true (e.g., the opt out rate is significantly higher than expected). Therefore the utilities may seek an increase in the $10 million cap if later circumstances warrant.

2. Authorize one or more of the specific pilot designs discussed in Section 3 and the formation of an advisory committee to meet periodically to review progress and provide advise to the joint utility program managers.

3. Specify or authorize the relevant cost recovery mechanisms discussed in Section 6, including the authorization as soon as possible of regulatory accounts to record the costs of reasonable preparatory work, such as market research, that needs to be done prior to the Phase I decision.

Prior to a significant commitment of expenditures, the utility distribution companies (UDCs) request explicit Commission authorization to spend such amounts and define the explicit cost recovery mechanism and process that will provide UDC funding within a reasonable period of the expenditures incurred by the UDC. The UDCs should (1) be allowed to established regulatory accounts to record incremental one-time and on-going program costs not currently covered in rates, (2) utilize established balancing accounts to recover under-collected revenues, and (3) utilize established balancing accounts to recover customer incentive payments. Of immediate importance, the UDCs request that the CPUC authorize as soon as possible the filing by each UDC of a regulatory account to record the costs of various activities which will occur between now and February 2003, when the CPUC is expected to issue its Phase I decision. These activities include certain market research and refinement of the statewide pilot design necessary to optimize the chance that the SPP study (expected to be approved in the Phase I decision) can be implemented by June 2003.

1.10 Glossary of Retail Electricity Rate Terms

This glossary is intended to describe terms used in this report only. It is not intended to take the place of existing rate glossaries, such as those put out by the CPUC, the Rate Design Study, EEI, NARUC, or NRRI.

Automatic control technology	Any technology that allows the customer or electric service provider to pre-program a control strategy - for an individual electric load, group of electric loads, or an entire facility - to be automatically activated in response to a dispatch.

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. In a *fixed-period* CPP, the time and duration of the price increase are predetermined, but the days are not predetermined. In a *variable-period* CPP, the time, duration and day of the price increase are not predetermined.
Demand rate	A per-kW rate, typically applied to the peak demand during each month.
Demand response (DR)	The ability of an individual electric customer to reduce or shift usage or demand in response to a financial incentive.
Dispatch	A broadcast signaling the initiation of a control strategy or price adjustment.
Dynamic rate	A rate in which prices can be adjusted on short notice (typically an hour or day ahead) as a function of system conditions. A dynamic rate cannot be fully predetermined at the time the tariff goes into effect; either the price or the timing is unknown until real-time system conditions warrant a price adjustment. *Examples: real-time pricing (RTP), critical peak pricing (CPP)*
Flat rate	A per-kWh rate in which the same price is charged for all hours during a predetermined time period, usually a season or year.
Information	Facts and data that facilitate consumer response to energy prices. 'Basic information' describes a tariff and its potential impact on expected monthly energy costs. 'Technical information' describes technologies that can be used to respond to the tariff. 'Energy information' describes the consumer's energy consumption patterns on an ongoing basis, to help the consumer adjust behavior and infrastructure to reduce monthly energy costs.
Interval meter	An electricity meter or metering system that records a consumer's load profile by storing in memory each consecutive demand interval, which typically consists of a period ranging from 5 minutes to an hour, synchronized to the hour. The meter can be read through a hand-held device (typically monthly) or through a data link to a central metering master station (typically daily).
Notification	Information provided to customers regarding price adjustments or system conditions. 'Day-ahead' notification provides at least 24 hours advance notice. 'Hour-ahead' notification provides at least one hour advance notice.
Price elasticity	A measure of the sensitivity of customer demand to price. Price elasticity is expressed as the ratio of the percent change in demand to the percent change in price; e.g. a 10% load drop in response to a 100% price increase yields a price elasticity of -0.10. 'Own-price' elasticity relates changes in peak period demand to changes in peak period price. 'Cross-

	price' elasticity relates changes in usage in one period to changes in price in another period.
Rate	The retail price of electricity per-kW demand or per-kWh usage. A rate may vary as a function of usage (tiered rate), demand (demand rate), period of use (time-of-use rate), or as a function of system conditions (dynamic rate).
Real-time pricing (RTP) rate	A dynamic rate that allows prices to be adjusted frequently, typically on an hourly basis, to reflect real-time system conditions.
Revenue neutrality	A regulatory requirement that any alternative rate design must recover the same total revenue requirement as the default rate design, assuming that customers make no change in their usage patterns.
Seasonal rate	A rate in which the price of electricity changes by season.
Smart thermostats	A heating, ventilation and air-conditioning (HVAC) thermostat that: (1) automatically responds to different electricity prices by adjusting the temperature set point or the operation of the HVAC equipment using pre-programmed thresholds that have been specified by the customer; (2) displays energy information and rates, and notifies the customer of rate changes; and/or (3) can be programmed to control devices other than the HVAC system.
System conditions	Any or all of the following: wholesale electricity costs, reliability conditions, environmental impacts, and/or the relationship between supply and demand.
Tariff	A public document setting forth the services offered by an electric utility, rates and charges with respect to the services, and governing rules, regulations and practices relating to those services.
Tiered rate	A rate in which predetermined prices change as a function of cumulative customer electricity usage within a predetermined time frame (usually monthly). Prices in an 'inverted tier' rate increase as cumulative electricity usage increases. Prices in a 'declining tier' or 'declining block' rate decrease as cumulative electricity usage increases.
Time-of-day (TOD) rate	A rate in which predetermined electricity prices vary across two or more preset time periods within a day.
Time-of-use (TOU) rate	A rate in which the price of electricity varies as a function of usage period, typically by time of day, by day of week, and/or by season. *Examples: TOD rate, seasonal rate.*
Time-varying rate	A rate in which prices change or can be changed within a 24-hour period. *Examples: TOD rate, dynamic rate*.

SECTION 2 - INFORMATION ALREADY KNOWN ABOUT DYNAMIC TARIFFS AND PRICE RESPONSE

2.1 Introduction and Summary of Findings

The Administrative Law Judge's Ruling Following the First Meeting of WG3 1 directed WG3 to identify "where significant information gaps exist in knowledge of small customer response to demand response programs or dynamic tariffs." (at 13) This section of the WG3 report fulfills that directive, presenting information on four major areas:

- Customer acceptance of time-varying pricing, including time-of-use and dynamic pricing (the latter differs from time-of-use rates in that pricing is typically not known until the day before the event)
- Customer response to dynamic pricing, in the form of load shape changes
- Information required to design demand response programs
- Data regarding demand response technologies and cost of those technologies

The discussion below is a summary of extensive information gathered on over 100 experiments and programs conducted in California, other states, and internationally over the past quarter century. Our collective conclusion is that this information provides a valuable resource regarding time-of-use and dynamic pricing tariffs, but that significant information gaps remain that are best addressed through conducting the pilot program proposed in this WG3 report.

The following conclusions can be drawn from the existing information:

Across a wide variety of geographical locations, a variety of researchers from academe, think tanks, utilities, and other organizations have found that consumers – on average – respond to time-varying prices by reducing usage during expensive time periods and shifting it to inexpensive periods.[5] However, the majority of the studies were conducted outside of California. Also, the conclusions from these studies should be tempered by the fact that the bulk of the studies were conducted more than a decade ago. Much has changed in the California market during just the past two years, with the introduction of additional residential rate tiers and rate surcharges and a utility supply portfolio that is a combination of utility-owned generation, long-term contracts signed by the Department of Water Resources (DWR), and spot market purchases. In addition, the studies do not include what WG3 proposes to test in the pilot, namely small commercial customer response to critical peak pricing generally and residential customer

[5] Faruqui, Ahmad and Stephen S. George, "The Value of Dynamic Pricing in Mass Markets," *Electricity Journal*, July 2002.

response to critical peak pricing without automated response technology.[6] Thus, while these studies have generated useful information on price elasticities, it is unreasonable to rely only on such elasticities in evaluating major new programs in today's climate without conducting a current, comprehensive, and well-planned pilot program as proposed by WG3.

Customer demand response to time-differentiated prices varies by class (residential vs. small commercial), usage level, appliance holdings, climate, presence or absence of automated control capability, and program duration. Table 2-1 indicates the general trends:

Table 2-1. General Trends in Demand Responsiveness

Variable	**Higher elasticity**	**Lower elasticity**
Customer class	Residential	Small commercial
Usage level relative to others in same customer class	Higher monthly kWh per customer	Lower monthly kWh per customer
Appliance holdings	More appliances; air conditioning	Fewer appliances; no air conditioning
Climate	Hotter or colder	Milder
Automated control capability	Automated control present	Automated control absent
Program duration	Long-term	Short-term

With regard to automated control, while it can be said safely that enabling control technologies enhance customer response, it is not possible to say with confidence that the benefits of enhanced response can cover the greater cost of any specific technology.

The level of demand response, or price elasticity, has been tested and measured for a wide variety of customers and programs, primarily time-of-use programs but also several dynamic pricing programs. However, significant gaps and uncertainty remain, as can be seen in Table 2-2.

[6] Only one American study has derived price elasticities for critical peak pricing; it pertains to a pilot program offered by GPU in Pennsylvania. The GPU program involved critical peak pricing offered in conjunction with a smart thermostat. In work conducted for PG&E, Charles River Associates (CRA) showed that this type of dynamic pricing is likely to be substantially more cost-effective than simple time-of-use pricing. CRA found similar results in projects conducted for Xcel Energy and Puget Sound Energy. In any case, there is considerable uncertainty as to the actual level of benefits that can be achieved, as such benefits are dependent on key drivers such as marginal capacity costs, price elasticity, and participation (opt-out) rates.

Table 2-2. Customer Demand Response Estimates

Program Type	**Range of elasticities**	**Range of peak demand reduction**	**Range of total usage reduction**
Residential time-of-use	**-0.05 to -1.3** *(SCE; North Carolina)*	**4% to 35%** *(Ontario; Duke)*	**0% to 23%** *(PG&E; Connecticut)*
Residential critical peak pricing	**-0.35 to -0.82** *(GPU; EdF France)*	**42% to 59%** *(Gulf Power; AEP)*	**0% to 6.5%** *(AEP; Gulf Power)*
Small commercial time-of-use	**-0.03 to -0.04** *(SCE; PG&E)*	None reported	**2.1% to 5%** *(McKinsey multi-utility data; Finland)*
Small commercial dynamic pricing	No studies	No studies	No studies

The statewide pilot that is proposed in Section 3 is designed to fill these gaps and reduce the uncertainties inherent in the ranges of response. The results of the existing literature, when combined with results from the pilot, will provide the CPUC with a database that can be used to accurately predict demand responses for new California programs.

Customer participation in dynamic pricing programs depends heavily on program design, with participation rates ranging from less than 1 percent to over 90 percent. Customer satisfaction levels for most programs are high, largely because most programs are voluntary. Importantly, poorly designed programs can result in angry customers and large drop-out rates, leading to early program termination.

A wide variety of metering and appliance control technologies have been utilized successfully in prior studies and their costs and performance have been well documented.[7]

Access to additional energy usage information generally results in consumers using less total energy. However, little is known about the impact of information technologies (such as a Web-based display of usage and pricing by time period) on customer response. Preliminary findings from the Puget Sound Energy Personal Energy Management program, while encouraging, are inconclusive about the impact of information on customer behavior.[8] Also, the costs of Web-based information treatments must be considered in determining whether they are cost-effective. However, since there is substantial interest in their perceived capability, it warrants testing in the scientifically controlled environment of the proposed pilot.

[7] See Goldman, C. et al., "Impact of Information and Communications Technologies on Residential Customer Energy Services," Lawrence Berkeley Laboratory Report LBNL-39015, October 1996.
[8] Only six percent of the participants viewed their energy usage on the program website.

The literature shows that price responsiveness by small commercial customers is substantially smaller than residential responsiveness. However, given the larger loads of such customers, it is possible that some subgroups (e.g., those between 20 and 200 kW) may have benefits sufficient to offset the incremental cost of metering. In addition, no dynamic pricing programs have been conducted for small commercial customers. These reasons warrant including these customers in the proposed pilot program as well.

In spite of the breadth and depth of the database, as noted above, important information gaps remain that can be filled by implementing the pilot program described in Section 3 of this report. These gaps can be summarized as follows:

- What will be the specific level of demand response, or price elasticity, for residential and small commercial customers in California's current energy situation; across a range of usage levels, appliance holdings, and climate zones; for critical peak pricing with and without automated control capability?[9]

- What are California customer preferences for critical peak pricing implemented via a voluntary opt-out approach, and what information do customers need to ensure that they are fully informed?[10]

As a result of the answers to the above two questions, are there specific customer segments where dynamic pricing makes sense and other segments where it does not?

Moreover, customers' awareness about California's energy issues has changed since the crisis of 2000-01, and no study has been conducted since then to capture this potential underlying shift in consumer perceptions, preferences, and responses.

The group expects that these gaps can be filled by implementing a combination of the market research and pilot program described in Section 3 of this report. The selection of these three information gaps was also reinforced by a preliminary PG&E analysis that the most uncertain factors in estimating the cost effectiveness of deploying dynamic tariffs and the meters to support them were the estimated price elasticity of the customers, the value, and level, of demand response expected, and the fraction of the customers who would willingly remain on a dynamic peak pricing tariff. Thus a focus on obtaining more information on customer price elasticities, the related level of demand response, and customer willingness to at least accept if not choose to opt into a dynamic tariff is vital to making a good decision about the merits of deploying dynamic tariffs and the infrastructure to support them.

In addition, the proposed pilot would generally fulfill the requirements for a dynamic pricing pilot contained in SB 1388. While the pilot does not implement each feature of SB 1388 as

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[9] - Critical peak pricing has been tested before only with automated control capability
[10] - Voluntary opt-out approaches have been tested before only with time-of-use pricing, not critical peak pricing

written, the pilot does fulfill the general objectives of SB 1388, and SB 1388 allows the CPUC to determine the specific details of the pilot.

A more detailed discussion follows.

2.2 Methodology

To conveniently summarize existing information on demand response from across the country, WG3 utilized the Small Customer Summary Matrix provided to the CPUC on October 1, 2002.

The Matrix is a summary of dynamic pricing, demand response, and advanced metering studies. It summarizes over 100 research papers and reports. It includes utility studies, government agency reports, and peer-reviewed academic papers. It also includes as an appendix a compendium of all of the papers and reports, which has the specific literature citations and abstracts or summaries of most of the papers and reports. Each of the papers or reports includes a detailed description of the methodology of the experiment or program. The time period covered is the past 25 years. The focus of the Matrix is the response of customers to time-of-use and dynamic pricing. It includes studies and programs for California, including all three major investor-owned utilities. It covers over 200 utility projects and programs, primarily in the U.S., but also internationally. With most projects having multiple rate or experimental treatments ("cells"), the Matrix represents an estimated 1,000 or more cells. While very extensive, the Matrix is not comprehensive; at least as many utility programs were not included as were included. However, a significant majority of the programs and studies most relevant to this proceeding was included.

With respect to price elasticity, scores of studies were documented in the Matrix. They included a range of rate structures: tiered, time-of-use, and dynamic prices, with most of the studies focused on time-of-use prices. The studies also included a range of major variables known to affect price elasticities:

- Customer class (residential, small commercial)
- Varying income, usage, and appliance ownership levels
- Climate, including summer vs. winter-peaking areas
- Short-term vs. long-term demand response
- Various participation approaches (mandatory, voluntary opt-in, voluntary opt-out)

To prepare the Matrix, each of the papers and reports was read from the perspective of the issues raised in this proceeding, with the results summarized in the Matrix. The format of the Matrix was developed by the Energy Division, except for the right-most column, which was added to identify the specific source of the information included in the matrix. Data was included only for actual experience and specific results. Papers and reports were included for qualified academic researchers, government agency researchers, utility analytical staff, and other industry experts. Preference was also given to published reports, reports filed with regulatory agencies, and presentations made in public forums.

2.3 Information Results: Customer Acceptance of Dynamic Pricing Tariffs

Customer acceptance of dynamic pricing tariffs is found to vary widely, with participation rates in voluntary programs ranging from below 1 percent to above 99 percent. Customer acceptance is also often expressed as preferences in the context of market research.

2.3.1 Issues Regarding Customer Acceptance

Successful demand response programs require that customers reduce peak usage in response to higher peak or critical peak prices or other incentives. However, customers must participate in a program before they can respond. Customer preference is one indicator of likely program participation, but customer acceptance provides a more meaningful indicator for demand response program design. In setting rates for electricity, the CPUC must balance various public policy objectives. If given the option, consumers would always choose lower rates and higher reliability, but these two goals conflict with each other. In light of these realities, the CPUC sets rates that customers will accept – not necessarily prefer – and that meet the cost, reliability, and other policy objectives of the CPUC. In light of this, our emphasis in the pilot design is to test acceptance rather than preference. Customer acceptance is defined as customer willingness to participate in a tariff and is best measured by actual participation. Nevertheless, customer preference, as measured by market research, provides valuable input to program design and is, thus, a key element of the proposed pilot.

In reviewing the customer acceptance literature, two issues are important to consider. First, customer inertia dramatically affects participation. Stated another way, most customers will stay with their current rate unless they are forced to choose another rate. One way of doing so is via a random assignment, followed by giving the customer the opportunity to opt out. This inertia results in part because most customers are not used to being offered choices or making active decisions about tariff selection. Automatic assignment to a tariff has been the norm for virtually all customers for the past 100 years in the industry. Thus, to the extent a customer remains on his or her current tariff when offered a dynamic pricing option, the customer is often expressing a lack of interest by, for example, not reading informational materials. Moreover, remaining on the current tariff is often the result of a preference for simply not changing rates as opposed to a preference for the existing rate. One factor in customer inertia is that the importance of energy usage for many residential customers is low compared to other household budget items. In sum, customers display strong inertia bias in their decision making.[11]

Second, customer preferences for and customer acceptance of tariffs are very different. Market research and opt-in participation to voluntary rate programs are often used to gauge customer preference. Market research is limited by the common result that customer statements of intent frequently differ from customer action. Opt-in participation is limited by customer inertia. Customer acceptance is better assessed when the customer's action takes these factors into account. Ways of more completely assessing customer acceptance include opt-out voluntary rates (with customer acceptance equated to remaining on the rate) and neutral choice options, where a customer chooses between tiered rates and dynamic prices equally, with no automatic assignment to either rate (in practice, this is best done when the customer first signs up for electric service).

2.3.2 Customer Preference Results – Market Research

Market research surveys have found consistent interest by residential customers in time-of-use and other demand response options. Typically, about half of such customers are interested in time-of-use pricing options when surveyed.[12] Customers have also been surveyed on a very limited basis regarding preferences for rate design options and information sources to assist them in saving on their bills. The results suggest preference for simple rate designs and for access to information via additional sources, including the Internet. According to latest surveys, 61.5% of California households own computers, and 55.3% of California households have access to the Internet [13] with low-income and ethnic customers lagging other customers in computer ownership and access to the Internet.[14] Thus, about half of the customers that prefer additional information on energy usage cannot receive that information via the Internet at home. Also, Puget Sound Energy noted that only about six percent of its program participants logged onto its website to view their data.[15]

2.3.3 Customer Acceptance Results – Program Participation

Customer actions are a more reliable indicator of acceptance than are market surveys. Such action includes both initial participation in a program and ongoing participation, as measured by customers adding to or dropping out of programs.

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[11] - Hartman, et al., "Consumer Rationality and the Status Quo," Quarterly Journal of Economics, 1991.
[12] - Power Perceptions, "The Energy Consumer, A Survey of Residential Electricity Consumers," Aug 2000.
[13] - US National Telecommunications and Information Agency (www.ntia.doc.gov/ntiahome/dn/hhs/TableH2.htm) and Iowa Workforce Development Department (www.iowaworkforce.org/trends/data/computers.xls)
[14] - "California's Digital Divide", Public Policy Institute of California, November, 2000.
[15] - Presentation in Experiential Workshop at the CPUC, September 10, 2002.

Most time-of-use and dynamic pricing programs conducted over the past 25 years have been voluntary. They included a mix of opt-out and opt-in programs. The opt-out programs included the time-of-use rate experiments conducted under the auspices of the Department of Energy during the late 1970s and 1980s. These experiments were set up to have mandatory placement on time-of-use rates by customers, but customers who complained about the programs were typically allowed to opt out of the experiments. The opt-in programs have included numerous time-of-use and critical peak pricing programs in which customers were typically recruited by direct mail.[16]

Opt-out programs typically have participation rates of over 90 percent, ranging to over 99 percent. However, customer expectations regarding opt-out programs are crucial. When Puget Sound Energy changed the rate design for its large-scale residential time-of-use program, the opt-out rate skyrocketed, customers were unhappy, and Puget had to cancel the program 10 months early. These customers had been saving money on the program in its first year but began losing money after a rate design change in July 2002 that increased the customer charge by $1 a month and reduced the ratio between peak and off-peak prices. With approximately 90% of the customers losing money and after receiving a large number of complaints, Puget terminated the program in November 2002 and is now reevaluating it.

Opt-in residential programs have participation rates from below one percent to over 18 percent, with most programs having participation rates below five percent (PG&E's residential time-of-use program has about two percent participation). One study estimated that under optimum conditions, an opt-in time-of-use or dynamic tariff program would have participation of approximately 20 percent.[17] Optimum conditions are defined as customers having 100 percent awareness of the program, zero transaction costs, and no inertia. Opt-in small commercial programs have similar participation rates, except that one program has over 30 percent participation.[18]

Fewer data exist on the effect of customer characteristics on program participation in time varying or dynamic tariffs. Where such data exist, they indicate that program participants span the full range of education, income levels, and appliance ownership. However, opt-in program volunteers tend to have slightly higher education, income, and appliance ownership levels than non-volunteers, based on the limited data available.

In California, time-of-use rates have been available to residential customers for over twenty years, though most customers are not aware of this option. Currently, about two percent of PG&E's residential customers are served on time-of-use rates (Schedule E-7). On average, they consume twice the electricity (approximately 12,000 kWh/year) consumed by PG&E's

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[16] - Another source of data would be customer choice of variable vs. flat prices in Georgia's natural gas market. So far, such data are not publicly available.
[17] - EPRI study reported in Wood, "Effective Demand Response Programs for Mass Market Customers," presented at NYSERDA Time Sensitive Electricity Pricing Workshop, October 3, 2002.
[18] - Baladi, "Voluntary Time-of-Use Customer Participation," EPRI Load Management Conference, May 1994.

average residential customers (approximately 6,000 kWh/year). Customers with higher usage levels are able to achieve greater savings on the rate. In this program, for customers who do not already have a time-of-use capable meter, there is an up-front installation charge of $277 as well as a monthly meter charge of approximately $1.50 (customers with pre-existing time-of-use meters pay a monthly meter charge of approximately $4).

Finally, again based on limited data, customers prefer simpler rate structures to more complex structures.

2.3.4 Customer Acceptance: Information Gaps and Suggested Actions

The information gaps regarding customer acceptance have to do with obtaining more information on the following specific areas:

- What acceptance levels will customers show with respect to opt-out, critical peak prices and what type of characteristics are associated with those customers that either remain on the program or opt-out?
- What are customer preferences for different specific tariff structures, different technology options, and different information options?
- What information do customers need to ensure that they are fully informed regarding their tariff choices and that they have realistic expectations?

Information on the first question is partly obtained through actual customer choices made in a pilot rate program, because it addresses the problem of customers saying one thing and doing another. The proposed pilot will provide some information on this issue. The market research portion of the pilot will be used to screen out undesired rate structures; this, followed by actual implementation, is to definitively determine customer acceptance. Information on the last two questions is best obtained through a combination of market research and a pilot program. The reason is that a very large number of options is available, and pilot testing all of them would be extremely expensive. Also, many of the options, such as technology, are evolving. Market research will be used to narrow the options, with a very small number of treatment options included in a pilot. The market research will include some combination of focus groups, phone surveys, and/or mail surveys, as best determined in the final research design.

2.4 Information Results: Customer Demand Response

As summarized in the table above, the studies found that customers, on average, reduce electricity demand in response to higher electricity prices and in response to having more information about their energy usage. The specific level of demand response is the critical determinant of cost effectiveness of demand response programs. Reported elasticities and demand reductions range widely – and are not available at all for small commercial dynamic pricing programs – thus supporting the need to perform the rate pilot recommended by WG3.

2.4.1 Information Results: Price Based Demand Response

The studies found that customers, on average, reduce peak electricity demand in response to higher on-peak prices. In parallel with the reductions in peak demand, most studies found a reduction in average total consumption when customers switched to dynamic prices. Also, the studies found that customers reduce total electricity demand in response to higher overall electricity prices. Within these general trends, the following specific findings are also of interest:

Price elasticities ranged broadly, depending on a variety of factors such as type of customer, load, income, appliances, type of business, and climate. This broad range increases the difficulty of forecasting actual demand response.

- Residential customer elasticities were higher than those for commercial customers
- Residential customer elasticities were typically higher for customers with higher usage, more appliances, and air conditioning load
- Commercial customer elasticities varied widely by business type
- Price response was typically significantly higher – approximately double – when automated control capability was available
- Customers typically reduced total consumption by around three percent, with the range from zero percent to as high as 23 percent
- Customers reduced peak demands by a four percent (low end of time-of-use range) to 59 percent (high end of critical peak pricing range)

2.4.2 Information Results: Effect of Information on Energy Usage

Many studies examined whether simply providing residential customers with more information about their usage and electric bills would result in these customers reducing their consumption. A report summarizing 17 of these studies stated the following: “Several investigators analyzed the effects of feedback alone or in conjunction with other factors, such as goal setting and monetary incentives. Findings show that feedback alone and in conjunction with other factors can be effective in reducing electricity consumption… The bulk of the literature provides evidence that information feedback can play a role in reducing electricity consumption on the order of from 5% to 20%."[19] It should be noted that these findings included both time-differentiated and non-time-differentiated rates. The same study emphasizes that additional research is needed.

2.4.3 Demand Response: Information Gaps and Suggested Actions

The information gaps regarding demand response have to do with obtaining more information on the following specific areas:

- What is the specific demand response curve for dynamic pricing in California (can the range of responses be narrowed)?
- How will that curve vary by customer usage level, appliance holdings, control technology, and climate?
- What is the demand response curve for small commercial customers in California?
- How will the provision of different levels of information, in combination with dynamic prices, affect total consumption?

2.5 Information Results: Program Design

The studies cover a range of demand response programs and provide extensive information on program design. These studies include information on rate design, metering requirements, other technology requirements, information options, customer recruitment, and other program design elements.

2.5.1 Rate Design

The studies offer data on rate designs having different goals. Some rates are class revenue neutral. Others are rate schedule revenue neutral, with the dynamic pricing tariff reflecting the relative costs associated with customers participating on the tariff, based on the aggregate loads of those customers. Some rates include metering costs in customer charges or distribution rates; others have a separate meter charge. Rates that have the goal of affecting customer usage should not include large fixed charge components (high customer charges) since these charges are unavoidable and dilute incentives to reduce energy usage. As was learned from the Puget experience, it is important that customers have a reasonable opportunity to benefit from dynamic pricing rate design.

[19] - Farhar, B.C. and C. Fitzpatrick, "Effects of Feedback on Residential Electricity Consumption: A Literature Review," by Solar Energy Research Institute for the U.S. Department of Energy, 1989.

Most of the rate studies and programs were for time-of-use prices or air conditioner load control. Only a handful were for critical peak prices. However, critical peak prices were found to result in much higher load reductions than time-of-use rates and to be more cost-effective than time-of-use rates alone.

2.5.2 Equipment Requirements

Equipment requirements are a function of the rate design. For example, a time-of-use rate requires a time-of-use meter, while a critical peak pricing rate requires an interval meter. In some cases, customers are provided with automated control capability, such as smart thermostats, to assist in responding to critical peak pricing. In other cases, customers have sole responsibility for obtaining and utilizing control equipment. One simple example is appliance timers, which many customers use in responding to time-of-use rates (however, such timers would not respond to critical peak prices having fluctuating critical peak hours). A large variety of metering and controls technologies are available and have been utilized to support the implementation of demand response programs. A more detailed discussion of technology requirements is included in Section 7, the report of the Technology Subcommittee of WG3.

2.5.3 Value of Demand Response

In most programs, researchers examined the question of cost effectiveness, if only briefly. These studies generally concluded that demand response pricing programs, including time-of-use rates, resulted in significant savings in specific situations. These savings occurred in avoided generation costs, avoided transmission and distribution costs, and environmental benefits, including avoided power plant siting and construction and reduced air pollution emissions.[20] A commonly used measure of avoided generation capacity costs was a natural gas-fired combustion turbine peaker. Another consideration would be to incorporate not only the costs of alternative resources, but also the beneficial externality of reduced peak period prices created for all customers through the actions of a specific set of customers reducing their peak demands.

Overall cost-effectiveness of the tariffs or programs generally depended on whether the savings exceeded the higher cost of providing metering that could support time-based pricing. Some studies found that the benefits exceeded those costs; a smaller number of studies found that the benefits were less than the costs. In all cases, the cost-effectiveness depended on the specific demand response measured for or expected for a given set of customers (in turn, a function of a specific tariff), the value of avoided capacity, and the

[20] - Some commenters have noted that time-of-use rates have the potential to trade off reduced natural-gas fired generation during peak hours with increased coal-fired generation during the off-peak hours. The literature reviewed did not include any findings on this issue one way or another.

specific metering and other implementation costs for that set of customers. Thus, cost-effectiveness is highly specific; the rate pilot and detailed analyses are essential in evaluating cost-effectiveness for California's small commercial and residential customer classes.

2.5.4 Program Design: Information Gaps and Suggested Actions

The information gaps regarding program design have to do with obtaining more information on the following specific areas:

- What specific rate designs for dynamic pricing should be implemented in California and for what customers?
- What is the cost-effectiveness of dynamic pricing in California to the participating customers, the utility, and California? How will those costs and benefits be shared and allocated among customers and utilities?

Information to answer these questions can be obtained partly from the pilot proposed in Section 3, including market research and actual implementation. Answering the second question also requires an estimate of avoided costs. This estimate is to be provided by WG3 1.[21] Combining the demand responsiveness results with the avoided cost estimate will yield an estimate of overall cost-effectiveness. The process of conducting a cost-effectiveness analysis is more fully described in Section 4 of this report.

2.6 Information Results: Available Technologies

Implementing demand response programs requires three basic sets of technology: measurement, notification, and control. Section 7, the report of the Technology Subcommittee, summarizes the technology requirements for specific tariff types (time-of-use, critical peak pricing, etc.).

The first technology, metering, is required to measure the results of demand responsive actions, *i.e.* how many megawatts of load reduction resulted from a specific pricing or other demand response program activity? Response can be measured individually or by sampling a larger group of customers. The former approach is required for pricing programs. The latter is often used for highly homogenous populations and programs, in particular air conditioner load control programs.

The second technology needed to achieve demand response is notification of customers to communicate pricing and program information and to notify customers of "dispatch" events. This "technology" ranges from letters and bill inserts to emails, smart thermostats, and Web displays of information. Mass media are also used, such as press releases and radio announcements of California ISO system emergencies. In some cases, such as with air

[21] - R.02-06-001 ALJ Ruling the Second Meeting of Working Group 1, at 7.

conditioner load control programs, customers are not notified at all; naturally, this would not work for pricing programs, where some form of notification is necessary.

The third demand response technology is the control technology used to turn down or off appliances or equipment in response to a dispatch signal or pricing incentive. As with notification, automated technology is helpful but not required. Appliances and equipment are often controlled manually in time-of-use programs, while automated control – an example is smart thermostats – has been used in the load control and critical peak pricing programs implemented in the U.S. to date. In this regard, the proposed pilot specifically addresses, for the first time, the level of customer demand response to critical peak prices in the absence of automated controls.

The focus of the analysis culminating in the Matrix was on customer response rather than technology. However, the studies do provide important information regarding technologies available and utilized. Additional information is provided in the Summary Report of the Experiential Workshops held at the CPUC on September 9 and 10, 2002.

2.6.1 Metering Technologies

Typical electricity meters, applicable to over 95 percent of electricity customers in California, record electric usage continuously and allow only manual meter reading. By reading these meters monthly, the investor-owned utilities are able to implement rates based on monthly charges, including monthly total consumption, monthly consumption by time-of-use period (presently available only on a limited number of specific meters capable of time-of-use functionality), and monthly maximum demands (presently available on a limited number of meters capable of demand functionality and installed on medium to large commercial customers). Advanced metering includes the ability for meters to record usage more frequently than monthly and usually includes the ability to retrieve the data remotely via a communications network.

Programs included in the matrix were implemented using a variety of metering technologies. Some used monthly read time-of-use meters or data recorders (for usage intervals as short as every 15 minutes); others used advanced metering with wireless, telephone, or power line carrier communications.

Metering can be done for each individual participant in a program or on a sampling basis for a large population of customers with similar characteristics. An example of the former is time-of-use pricing; an example of the latter is residential air conditioner load control programs. When meters are implemented on a sample basis, incentives are paid based on average demand response. Individual customer response in such programs may vary widely, especially if the population is heterogeneous. For the programs assessed in the Matrix, individual meters were utilized for all price-based programs and all programs for which payment was directly dependent on the amount of load relief provided.

A range of metering costs is provided in Section 7, the report of the Technology Subcommittee.

2.6.2 Control Technologies

Control technologies include utility-dispatched and operated controls and customer-controlled controls. The former is more common for reliability-based demand response, while the latter applies more frequently to price-based demand response. The technologies vary widely and many apply to both residential and to small commercial customers (such as a smart thermostat). The current generation of devices vary by whether they use outbound-only communication (from the central system to the device) or two-way communication. One-way systems use either one-way paging networks or piggyback on existing VHF/UHF communication systems. Two-way systems use two-way paging networks, telephone combined with paging, two-way power line carrier, two-way wireless data systems, or other communications. Two-way communication provides the ability to monitor device operation. The majority of currently installed devices use only outbound communication.

Utility-dispatched control for small commercial and residential customers usually consists of utility-operated load control of residential and commercial air conditioners, swimming pool and spa pumps, and, less commonly, residential electric water and space heaters. This technology uses a radio signal to turn off or cycle customer loads during times of system peak. It consists of a switch wired into the control circuit of the air conditioner or water heater. Newer control switches are relatively “smart” and are able to adapt control levels to each dwelling based upon duty cycle. A newer development is the use of a smart thermostat. These have communications capability and can be used to control the customer’s temperature based on a signal received from the utility or parameters programmed by the customer, such as response to price signals.

Both smart thermostats and smart control switches can offer customers the ability to override the utility signal and opt out of control. Smart thermostats typically have an override button. Many smart thermostats and load control switches can be overridden by going to a website or calling a toll-free number.

Smart thermostats, because they can operate in terms of dwelling temperature, add the option of allowing a customer to choose a dwelling temperature to correspond to a varying energy price. Thermostats also provide the option for either the customer or the utility to “pre-cool” in anticipation of control. Precooling by a degree or two can allow the utility to curtail the air conditioner for a longer period of time without an adverse affect on comfort.

To date, there has been no implementation by utilities of load control beyond air conditioning, water heating, pool pumps, and electric space heating. Control of other appliances and lighting has been done by customers only. There has been discussion and product announcements associated with centrally controllable refrigerators, washing machines, dishwashers, and other appliances. However, no large-scale installations exist.

On the price-response side, the programs included in the Matrix included many without control technologies, such as the majority of time-of-use programs. The simplest control technology utilized in these programs – beyond manually turning off appliances or equipment – was appliance timers and programmable thermostats. The next higher level of automated customer control was a smart thermostat. Smart thermostats used in price-response programs can be programmed to adjust temperature according to the customer's desires and based on a price (not control) signal received from the utility. Smart thermostats can also display the rate in effect, such as a critical peak price, providing customer notification capability. Beyond smart thermostats, more capable systems include home control gateway systems – some using a personal computer – that can control multiple appliances, and energy management systems for commercial buildings and facilities.

Control technology costs can be deployed by utilities or left to consumers to choose which should be implemented. Further, the selection of control technologies can be tailored to specific customer situations. The literature shows that control technologies are helpful but not essential. An important consideration is the importance of customer education and notification. All of these factors need to be included in any cost-effectiveness analysis for implementing control technologies, as well as policy choices about dynamic pricing programs.

2.6.3 Technologies: Information Gaps and Suggested Actions

The information gaps regarding technology have to do with obtaining more information on the following specific areas:

- What are the capabilities and costs of technologies available to Californians?
- What types of technologies are customers most comfortable using to respond to critical peak prices for day ahead and hourly dispatch?

The former question can be addressed through the collection of information from various technology providers. This information was collected by the Technology Subcommittee of WG3 and is included as Section 7. The latter question is expected to be further investigated and understood as a result of the market research to be conducted in the proposed pilot.

2.7 Conclusion

In order for the CPUC to be able to assess the cost-effectiveness of small commercial and residential dynamic pricing and demand response programs, the CPUC requires reliable and specific data on price elasticities and customer preferences. Our conclusion is that, in spite of a large amount of good data being available, major information gaps exist that can be filled only by implementing the pilot proposed in this report.

To reach this conclusion, WG3 reviewed extensive information gathered on a wide range of programs conducted in California, other states, and internationally over the past quarter century. This information provides a valuable resource regarding time-of-use and dynamic pricing tariffs, but significant information gaps remain. The gaps relate to information specific on price elasticities and customer preferences that WG3 proposes to gather through the scientific, well-planned, comprehensive pilot program documented in this report. The specific information to be gathered includes price elasticities and customer preferences accounting for the following features:

- California's current regulatory, energy, and economic climate
- Critical peak pricing with and without automated response
- Preferences of Small commercial and residential customers
- A variety of electricity usage levels, appliance holdings, and climate zones
- Voluntary (opt-out) rates

WG3 is confident that the proposed pilot can fill the information gaps and urges the CPUC to approve the pilot expeditiously.

SECTION 3 - PILOT PROPOSALS AND MARKET RESEARCH

3.1 The Statewide Pricing Pilot

This section presents the design for a Statewide Pricing Pilot (SPP) to determine the amount of demand response that can be triggered by dynamic pricing in the small customer (<200 kW) market in California. The design integrates several of the proposals that were presented to WG3. SPP embodies a comprehensive approach that satisfies the goals and objectives of the OIR; balances the interests of the majority of the stakeholders involved in WG3; leverages resources across the state; maximizes the likelihood that rate options are in place by June 2003; and is expected to produce valid preliminary results by the fall of 2003.

SPP is designed to measure the impact of three specific time-varying rates on customer electric consumption and coincident peak demand: (1) time-of-use (TOU) rates, (2) fixed critical peak pricing rates (CPP-F) and (3) variable critical peak pricing rates (CPP-V). TOU rates feature higher prices during one or two peak periods and lower prices during an off-peak period. CPP-F rates resemble a standard TOU rate on most days of the year, and a fixed higher rate during ten to fifteen days of the year. The higher rate applies to the hours that would otherwise have constituted the highest price period. Customers receive day-ahead notification for all CPP-F days. CPP-V rates differ from CPP-F rates in that the critical peak period may be called on the day-of the event, and it is not confined to a fixed number of hours that are known in advance.

The remainder of this section is organized as follows. Section 3.1 provides an overview of SPP's research objectives. Section 3.2 discusses the specific experimental and sample design of SPP. Section 3.3 provides background information on the scientific principles of experimental design that have guided the development of this pilot proposal. Section 3.4 addresses the market research that will be done in conjunction with SPP. Section 3.5 contains a cost benefit analysis of SPP.

3.1.1 Overview of Research Objectives

WG3 meetings identified the need for a pilot program to test a variety of innovative rate options, with and without enabling technologies and information treatments. This SPP proposal is intended to:

- Provide the information required for policy making by WG1 (i.e., fill the "information gaps" identified in Section 2);
- Integrate the effort statewide, thus eliminating duplication of effort across utility service areas and allowing better use of financial resources and time; and

- Be implementable by June 1, 2003. Priority will be given to installing the necessary metering for customers with existing smart thermostats in the SCE and SDG&E service areas, to ensure that these customers will be ready to receive time-varying price signals by June 1, 2003.

SPP is designed to yield estimates of price elasticities associated with these three types of rates, which can be used by each of California's three investor-owned utilities (IOUs) in constructing their business plans in Phase II of this proceeding. In order to contain pilot costs, the IOUs and the CEC are not proposing to test all of the possible combinations of weather, dynamic rates and technology treatments for each IOU's area. SPP is based on the understanding that even though certain rate, information, or technology treatments are not conducted in each IOU's service territory, the cells and treatments will be designed in such a way as to allow the results to be generalized across IOU service territories. With this caveat, each IOU would be willing to use the elasticity results for rate or technology treatments obtained for randomly sampled cells from another IOU's service territory as part of its business case analysis. Accordingly, neither the utilities, the CEC, nor any other WG3 participant (unless noted in a dissent to this section 3) anticipates the need to ask for a substantial amount of additional funding later in 2003 to test all combinations of rates and technologies in each discrete service territory.

While SPP is designed to test customer response to dynamic pricing signals, it is not designed to test the effect of “incentive” or pay for performance programs. A few WG3 participants have advanced such incentive programs, and their proposals are presented elsewhere in this report. However, WG3 decided that the focus of SPP should be on dynamic pricing tariffs.

From a pricing strategy perspective, the objective of SPP is to help California avoid two types of potentially costly policy mistakes that are possible in light of the current uncertainty associated with customer response (see Section 2) and the resulting benefits (Section 4) associated with wide scale deployment of advanced metering and alternative rates. Full-scale deployment of advanced metering across California is a multi-billion dollar decision and, as such, must be based on substantial evidence regarding resulting benefits. In the absence of such evidence, one type of mistake would be to require such implementation only to learn that the resulting benefits are less than the cost of implementation. A second type of mistake would be not requiring such implementation when the benefits of doing so significantly exceed the cost.

The best way to insure that the state does not make either of these potentially costly mistakes is to conduct a well-designed pilot consistent with scientific principles of experimental design. Because time and resources are limited, no pilot can hope to address all conceivable objectives, and it is therefore useful to prioritize objectives. SPP’s primary objectives are to:

- Estimate period-specific energy usage and peak demand impacts of specific innovative rates and/or technology and information options

- Estimate own-price and cross-price price elasticities of demand for various pricing periods[22]

Important secondary objectives are to:

- Assess the impacts of and customer preferences for rates, control technologies and feedback about the impact of shifting energy use patterns

- Assess the impact of giving customers access to more detailed usage information on their usage patterns

There are two key issues in developing dynamic pricing options and evaluating the benefits of advanced metering systems. One concerns the impact of new rates, information and technology treatments on the average participating customer. This issue can be addressed through a well-designed experiment, which is often the only way to estimate the impact of rate treatments (coupled with information and technologies) on energy usage and peak demand for the average participating customer. Technology treatments for the pilot will be designed following the results of a market research program to identify customer preferences. This market research is described in Section 3.1.4.

The second key issue concerns customer preferences for rate and other treatment options and participation in rate programs. Participation rates will vary depending on whether a program is an opt-in or opt-out program, with participation rates being much higher in the latter than in the former. Participation rates can be estimated directly as part of the pilot structure itself, i.e., by making the pilot a true opt-out pilot, or they can be estimated through ex post market research (though market research results are less reliable than observed actual customer behavior). SPP is designed to estimate participation rates for opt-out programs as part of its design. Additional market research among pilot participants will be performed at the end of SPP, as discussed in Section 3.1.4.

3.1.2 Design of Statewide Pricing Pilot (SPP)

3.1.2.1 Conceptual Approach

Econometric analysis will be used to measure the impact of rate and other treatments on usage and peak demand patterns of participants who are subject to various treatments and of suitable control groups. The data collected during the pilot will be used to estimate

[22] See glossary.

mathematical functions (e.g., demand equations) that relate usage during specific time periods and coincident peak demand to a variety of determining variables, including:

- Price level
- Housing type for residential customers and commercial business type for commercial customers
- Customer size, measured by usage amount
- Equipment holdings
- Variations in climate and weather conditions over time
- Demographic and firmographic characteristics, including income.

An example of such a functional relationship is provided in the following equation.

Ln (On-peak kWh) = A + B1*Ln (On-Peak Price)

+ B2*Ln (Off-Peak Price)
+ B3*(A/C Ownership)*(Cooling Degree Hours)*Ln (On-Peak Price)
+ C1*(A/C Ownership)*(Cooling Degree Hours)
+ C2*(Persons Per Household)
+ C3*(Dwelling Type)
+ C4*(Pool/Jacuzzi Ownership)
+ C5*(Electric Clothes Dryer Ownership)
+ C5*(Household Income)

In this equation, B1 and B2 are the own-price elasticity and cross-price elasticity of demand. B3 is an interaction term that is designed to measure the impact of air conditioner ownership and weather conditions (cooling degree hours) on the own-price elasticity of demand. Once these functional relationships are established based on the pilot results, they can be used to predict how customer responsiveness will vary across price levels and rate treatments that were not specifically included in the pilot. Entering the appropriate values for each explanatory variable on the right-hand-side of the demand equations can do this. Similarly, response estimates for a wide variety of customer populations (e.g., typical residential customers for specific utilities, high users in hot climates, etc.) can be estimated by entering the average values representing these populations on the right-hand-side of the demand functions. This ability to extrapolate outside the specific rates tested in the pilot and to alternative sub-populations is a key feature of the pilot design and will provide policy makers with a robust and valuable tool for assessing the cost-effectiveness of meter deployment and rate strategies.

3.1.2.2 Target Population

The primary target population for the pilot is the residential customer class. The emphasis and the bulk of the pilot resources are appropriately directed at residential customers for two primary reasons:

- Other experiments have shown that residential consumers, on average, demonstrate much greater responsiveness to time-varying rates than do commercial consumers; and
- Decisions regarding full-scale deployment of advanced metering hinge more on estimates of the potential operational and demand-response benefits of residential consumers than on that of other customer groups because residential customers account for about 90 percent of all meters.

Nevertheless, some attention toward small commercial consumers is warranted. In spite of the fact that other studies show that price elasticities for small commercial and industrial (C&I) customers are substantially lower than those of residential consumers, the aggregate response from C&I customers can still be significant, as average usage for these customers is much larger than for residential consumers. Furthermore, all other known studies for such customers have only examined demand responsiveness to static, TOU rates, and not to the dynamic CPP-F and CPP-V rates that will be tested in this pilot. Thus, inclusion of some C&I customers in the pilot will break new ground with regard to the tariffs tested.

3.1.2.3 Population Segmentation

Segmentation is required when one wishes to make statistically valid statements about certain sub-populations with a specified degree of precision. For example, if one wishes to know how the responsiveness of households in a specific climate zone differs from that of households in a different climate zone, one could draw separate samples from each climate zone. Potential segmentation characteristics include service territory, housing type, climate zone, income level, size (as measured by annual consumption), and age of house.

It is still possible to predict how responsiveness might vary across sub-populations in the absence of segmentation using the demand-modeling approach as illustrated by the equation in section 3.2.1. As long as there is sufficient variation in the pilot sample across the sub-population characteristics of interest and the demand-model is specified with the appropriate interaction terms, one can estimate the equation coefficients with adequate statistical precision and then predict responsiveness for the desired sub-populations by entering values for the population averages on the right-hand-side of the equation.

The precise segmentation scheme that will be used in the SPP continues to be under investigation. Currently, there is a reasonable consensus that segmentation should be done by climate zone for residential consumers, and preliminary data analysis indicates that three or four climate zones statewide are likely to be sufficient.[23] Background information on climate zones is contained in **Table 3-1** for three IOU service areas and five climate zones. Preliminary analysis indicates that it may be possible to rely on just three climate zones, since they contain 97% of the state's population of customers. For

[23] We note that even though only four climate zones may be used for the segmentation process, the demand-modeling will rely on greater granularity in climate and weather information to more accurately capture the influence of micro-climates and weather variation on demand.

commercial consumers, segmentation by size (e.g., <20kW and 20kW to 200kW) will be implemented.

Table 3-1. Mapping of Climate Zones

Baseline Mapping

New Zone	Utility	Baseline Territory First Cut	Baseline Territory - Second Cut	Population Count - Basic Service	Population Count - All Electric Service	Total Population	CDD Average	CDD Range *	Summer Basic kWh/day	All-Electric kWh/day
	SCE	16	Low-population zones of SCE & PG&E combine with zone 2 (don't know about SDG&E)	59,400	17,600	77,000	674	4 - 2398	10.0	14.3
	SDG&E	Mountain		6,000	6,000	12,000	746	455 - 935	15.5	18.4
	PG&E	V		39,448	7,575	47,023	19	3 - 47	8.7	15.1
		Y		19,703	35,572	55,275	410	81 - 995	10.8	14.3
		Z		1,709	4,202	5,911	125	8	7.3	10.6
1				**126,260**	**70,949**	**197,209**	**432**		**9.9**	**14.5**
	SCE	10	10	1,428,200	203,600	1,631,800	624	301 - 1079	10.2	10.0
	SDG&E	Coastal	Coastal	503,000	128,000	631,000	837	719 - 814	10.2	9.8
	PG&E	T	T	893,839	154,350	1,048,189	171	6 - 542	8.5	10.4
2				**2,825,039**	**485,950**	**3,310,989**	**521**		**9.7**	**10.1**
	SCE	-	-	-	-	-	-	-	-	-
	SDG&E	Inland	Inland	348,000	119,000	467,000	1273	1002 - 1580	11.8	11.6
	PG&E	X	X	1,402,529	226,059	1,628,588	655	287-1083	12.2	11.4
3				**1,750,529**	**345,059**	**2,095,588**	**793**		**12.1**	**11.5**
	SCE	13	Combine zones 4 & 5, but will lose extreme desert	124,200	7,600	131,800	1558	1386 - 1793	19.4	29.0
		14		227,700	21,900	249,600	1797	1196 - 2805	17.0	20.6
		17		1,516,100	120,200	1,636,300	1227	473 - 1539	15.4	16.9
	SDG&E	-		-	-	-	-	-	-	-
	PG&E	P++		65,506	86,630	152,136	901	781 - 1146	15.8	19.5
		R		370,345	66,239	436,584	1767	1495 - 2109	17.5	22.1
		S		572,409	89,999	662,408	1322	949 - 1628	15.8	19.5
		W		189,246	13,347	202,593	1941	1784 - 2236	18.7	23.8
4				**3,065,506**	**405,915**	**3,471,421**	**1394**		**16.2**	**19.5**
	SCE	15	Combine zones 4 & 5, but will lose extreme desert	97,900	13,900	111,800	3183	2938 - 3786	47.6	42.7
	SDG&E	Desert		1,200	2,000	3,200	3515	3515**	17.3	19.5
	PG&E	-		-	-		-	-	-	-
5				**99,100**	**15,900**	**115,000**	**3192**		**47.2**	**39.8**

* CDD range is range of weather stations in zone
** Only one weather station (Borrego) in zone
\+ Data from filings in Baseline OIR 01-05-047 Summer Season CDD Base 65
++ P (Lake County) belongs to the same climate zone as X, while P (Foothill) is merged with S for load studies

A number of WG3 participants have suggested that the pilot focus specific attention on selected market segments. For example, the San Francisco Community Power Cooperative (SFCPC) has requested that the pilot include a module focused on a specific sub-population within the PG&E service territory and The Utility Reform Network (TURN) and others have expressed an interest in being able to distinguish responsiveness between large and small residential consumers. Also, TURN has expressed an interest in a pilot focused on new construction.

SPP incorporates the SFCPC's proposal by including one additional segment in the San Francisco Bay Area. This segment will include two cells, one that will receive a treatment (discussed in the following section) and one that will act as a control for this special segment. With respect to the TURN request for a pilot that focused on larger homes in the new construction market, this issue will be handled by including customer size as a right-hand-side, interaction variable in the modeling phase of the analysis. Consideration will also be given to stratifying by size in the sample plan (e.g., over sampling larger consumers), so as to ensure that there will be sufficient representation of larger customers in the sample. However, in the interest of keeping the overall pilot costs reasonable, the residential sample will not be segmented by customer size.

3.1.2.4 Experimental Treatments

The number of possible tariff options, information treatments and complementary technology options that are of interest to policy makers is vast and, with unlimited funding and no time pressures, all of these options could be tested through an experimental pilot. However, prioritization and focus are essential to keeping overall pilot costs reasonable. Investigating the relative effectiveness of five to ten rate types, each with and without multiple information and technology treatments, would be very expensive and, with certainty, would jeopardize the ability to implement the pilot in time for summer 2003. The SPP proposal seeks to strike a reasonable balance in selecting the number and type of treatments that will be implemented.

California's electricity consumers currently face a complex, multi-tiered rate structure. Such a design may provide customers an incentive to conserve, but it does not encourage them to shift usage from expensive peak periods to comparatively less expensive off peak periods. Several studies have quantified the substantial benefits that can flow from instituting easily understood time-varying rates. In Section 4, PG&E and CRA present an analysis that shows the net benefits of CPP-F range from half a billion to a billion and a half dollars, measured in net present value terms over 15 years.

The SPP is designed primarily to test the extent of shifting that can be induced by time-varying rates, and secondarily to obtain data on customer opt-out rates. Different time-varying rates allocate different shares of the risk of wholesale price volatility between the utility distribution company and its retail customers. For example, a flat rate imposes significant risks on the utility and almost no risk on the customer. At the other end of the spectrum, a day-ahead hourly spot price rate imposes no risk on the utility and a significant risk on the customer. Ideally, one would design a pilot to test a variety of time-varying pricing options, including:

- Seasonally-varying rates; these rates are fairly common throughout the country, and do not involve any metering expense
- Two-period and three-period TOU rates; about 100,000 residential customers are on such rates in California, and a couple million residential customers are on such rates around the country; several million customers are on such rates in France
- CPP-F rates that raise prices during the normal peak period when extreme conditions are encountered in wholesale markets, along the lines of the *tempo* tariff offered by EDF; several hundred thousand French customers are on the *Tempo* tariff
- CPP-V rates that can dispatch critical prices at any time of the day and during any day of the year when extreme conditions are encountered in wholesale markets, along the lines of Gulf Power's program; about 3,000 Floridians are on the Gulf Power tariff, and the number is targeted to grow to about 40,000 customers in ten years

- Day-ahead and hour-ahead real-time pricing rates, in which the price of electricity varies on an hourly basis; a handful of residential customers are on such rates in California; it is not known whether such rates have been offered to residential customers anywhere else in the country, even though they have been offered to a few thousand large customers in the southeastern United States

Rate Treatments

As noted in Table 3-1, the SPP will test three primary rate types, a static TOU rate, a CPP-F rate and a CPP-V rate. A static TOU rate could be implemented using manually-read standard TOU meters whereas a dynamic rate requires daily reads and, thus, remote meter reading capability. Thus, if only a dynamic rate is tested, an important question would remain unanswered—namely, “Are the incremental benefits of a dynamic rate sufficient to offset the incremental cost when compared to both the existing rates as well as to a traditional, static, TOU rate?” To answer this essential question, it is necessary to include both static and dynamic rates in the experiment.

The precise characteristics of the CPP-F rate to be tested will be developed over the coming months. However, it is likely to have the following elements:

- For all days other than CPP days, a TOU rate would be in effect
- The CPP rate would be announced to consumers by one or more means (to be discussed in the next section) the day before it is to go into effect
- The rate could only be called a maximum number of times a year (e.g., 15), but these days would not necessarily be constrained to the summer period as defined by the seasonal TOU rate (e.g., the CPP rate could be called for the winter peak period time block as well as for the summer)
- Each time it is called, the rate would apply to the peak period time block for the day (e.g., if the peak period for the TOU rate was for the six-hour block from noon to 6:00 pm, the CPP rate would apply to that entire time block on the CPP day).

The CPP-V rate would have a variable-length critical pricing period that would be invoked during the day-of the crisis.

A rate issue that is still under discussion concerns whether the TOU rates should include two or three time periods. The two-period rate is considered preferable both because it is consistent with the existing TOU rates and because it is simpler for consumers to understand and manage. Including both two- and three-period rates in the pilot would substantially increase sample size and cost. However, some WG3 members feel that a three-period rate should be tested in lieu of the two-period rate because this would give customers a stronger financial incentive to shift load from the peak to the off peak period as opposed to the partial peak period and potentially save more on their bills by switching to a CPP rate. This issue will be resolved during the ex ante market research phase of the pilot design.

In order to econometrically estimate demand equations, it is necessary to include multiple rate levels for each rate type. Specifically, for a two-period rate, it is necessary to have two different price combinations (plus the current tariff in effect for each control group) in order to estimate the demand equation. For a three-period rate, three price levels are required, which will expand the sample size significantly.

The specific price levels that will be tested are yet to be determined. They will be developed to ensure that:

- there is sufficient, independent variation across rates to support the estimation of price elasticities
- the range in prices included in the experiment is wide enough to bracket future supply conditions in the wholesale market
- rates are transparent and customer-friendly.

As an example, a price for the critical price period may be set based on the marginal cost of peak capacity and energy usage. Say the former is $85/kW-yr and the latter is $.14/kWh. If the critical peak period is expected to last 90 hours (15 days times six hours a day during the normal peak period, which might run from noon to six), and the rate was designed to exactly reflect marginal costs, the price during the critical peak period would be $1.08/kWh (equaling $.14/kWh and $.94/kWh, where $.94/kWh times 90 hours/year equals $85/kW-year). In order to statistically estimate a price elasticity of demand, a minimum of two points are needed along the demand curve, in addition to the starting price. Thus, a high value of $1.25/kWh and a low value of $.75/kWh may be selected for the CPP-F prices. It is important to note that customers on the CPP tariff would receive a discount for all or most non-critical hours in the year and that their total bill, on average, would be the same or less were they to make no change in their usage. Of course, by reducing critical peak usage, the customer would save compared to non-CPP rates.

Assuming a two-period TOU rate, the current plan is for one of the two price combinations for each rate option to have a relatively high peak-off-peak price ratio (say 2.5 to 1) and the other to have a more modest peak-or peak-off-peak price ratio (say 1.5 to 1). Again, customers not changing their usage would pay, on average, the same or lower bill as on non-TOU rates. This approach will allow us to determine if relatively modest prices and/or price ratios will provide adequate demand response or whether more dramatic prices are necessary in order to stimulate adequate response. It will also allow us, through supplemental survey research, to assess customer satisfaction with and preferences for these "high" and "low" alternatives.

Information Treatments

Information treatments refer to the type of information that would be presented to customers before, during and after the pilot. There are a large number of potential information treatments that could be tested. These vary with respect to content, timing, delivery mechanism and cost. When examining information issues, it is important to distinguish between general information and education about the rates and other treatment options that a customer will face, and more personalized and/or detailed information provided as input to the customer's ongoing usage decisions. The first type of information is essential for all consumers in the pilot (and for any large-scale roll out of new rates). This type of information is not a treatment effect, but an essential element of the pilot and will be provided to all consumers. The specific content of this information will be determined through further discussions between the utilities, the CEC, and other interested parties in December.

The second type of information, on the other hand, will be handled as an experimental treatment. This type of information can be costly to deliver in a timely and personalized manner, and therefore, it is important to test whether the incremental, demand-response impact of such information justifies the incremental cost. Such a test will be limited to one treatment cell in one climate zone. Consideration will also be given to offering all customers access to such information for a monthly service fee.

General agreement has been reached with the SFCPC to include a special information treatment effect for one hundred consumers that are randomly selected from electricity customers residing in the Bay View, Hunters Point, and Potrero Hill districts of San Francisco (zip codes 94107 and 94124). This area consists of a mixed income, demographically diverse population. It is home to two aging power plants, both of which generate above-average levels of air pollutants. For this segment, pilot participants will be provided with information about the economic and environmental consequences (e.g., polluting air emissions, reduced local service reliability) associated with peak power use, and informed of the potential to reduce reliance on a locally polluting power plant through adoption of the CPP-F tariff. Participants will receive educational information regularly and periodically to reinforce this message. In addition, participants will be contacted using various means to communicate when the critical peak periods are occurring.

Because of the unique, socio-demographic characteristics of this population, and the fact that it would be impossible to constrain the information dissemination to a subset of the target population, it will be necessary to draw a separate “control” group for this information treatment. The control group will consist of one hundred customers that are randomly selected from another community situated close-by a known and publicized environmental hazard, with similar socio-economic and demographic characteristics (e.g., Richmond or West Oakland) as well as similar climatic and other demand-driving conditions.

This SFCPC pilot module will enable policy makers to explore how environmentally oriented information, provided to a population with heightened sensitivity about air quality issues, may increase responsiveness to CPP-F. Results from the pilot can be used to develop targeted, cost-effective and beneficial CPP-F in communities facing challenges associated with polluting air emissions and geographic-specific reliability issues. Likewise, the pilot could assist policymakers in developing appropriate environmental education materials to the broader population that may serve to increase the cost-effectiveness of demand response programs. The pilot will also provide valuable data with which to evaluate how best to involve low income and diverse communities in CPP-F programs without costly investment in advanced metering and billing infrastructure.

Email represents an interesting information treatment option and is used as a standard critical peak notification method in the EdF tempo residential critical peak pricing program. Email's advantage is that it can be used to deliver specific and individualized information at very low cost; its disadvantage is that only about half of customers utilize email regularly (see Section 2). This option will be considered in further discussions.

Technology Treatments

There are also a large number of complementary technology treatments of potential interest, which range significantly in terms of cost, load-shifting potential, consumer friendliness and other important factors. Studies have shown that dynamic rates in combination with enabling technologies can produce substantial load shifting. However, studies have also shown that substantial shifting can occur even in the absence of enabling technology (e.g., in France). The SPP will examine the relative responsiveness to dynamic rates with and without enabling technology. The specific technology treatments that will be administered during the SPP will be identified during the focus groups that are conducted during the ex ante market research phase.

An idea under consideration is whether customers on the CPP-V rate should be offered a choice of technologies, including direct load control, timers for swimming pool pumps, and a smart thermostat technology that is currently being tested by SDG&E and SCE under existing pilots. This will be resolved in December through further discussions between the utilities, the CEC, and other interested parties. Customers may be charged a leasing fee for using these technologies during the duration of SPP.

Several WG3 participants have suggested testing more sophisticated automated control technologies involving always-on gateway systems that essentially provide home automation services in addition to serving as enabling technologies for dynamic pricing. These technologies also allow incentive based programs such as the one proposed by Invensys, as summarized later in this section. Such technologies may have merit but are not proposed as part of the statewide pilot for several reasons:

- The majority of WG3 participants agree that the focus of the pilot should be on dynamic rates rather than incentive programs
- Doing so would add significantly to implementation complexity, adding additional risk to the schedule
- These technologies are primarily suited to very high-use consumers rather than to the population as a whole and, therefore, are less important to the general decision regarding wide scale deployment of advanced metering; and
- The simpler technologies described above are sufficient to support the CPP-V rate that is being tested.

It is noted that the more advanced technologies might qualify for funding and field-testing through the CEC's PIER funding program, and their proponents may wish to approach the CEC with their ideas.

In summary, the SPP pilot will test three different rate structures, a static TOU rate, a CPP-F and a CPP-V. It will also, at a minimum, assess the impact of one information treatment and one complementary technology treatment. The specific characteristics of these treatment options will be refined based in part on input from the ex ante market research that is described n Section 3.4 as well as practical issues associated with implementation capabilities and schedule.

3.1.2.5 Participation Requirements

The primary purpose of SPP is to simulate the effects of large-scale rollout of time-varying prices, and to help narrow down the uncertainty in estimates of net-benefits. Results presented in Section 4 indicate that the net-benefits are heavily influenced by uncertainties in price elasticities of demand and in the rate of customer participation in dynamic pricing programs. In a large-scale rollout all customers could (or might) be placed on a time-varying tariff (such as a simple time-of-use rate) by default. They would have the choice of staying on that rate, or opting-out to another time-varying tariff (such as critical peak pricing) or to a non-time varying tariff (that may be an inverted tariff with as many tiers as the existing rates or with fewer tariffs).

In SPP, the overwhelming majority of customers would be selected using stratified random sampling techniques that are described in the next sub-section, and randomly allocated to various treatment and control cells. Each customer would be placed on a time-varying rate or a control rate, depending on the cell they have been allocated to. Those on a time-varying rate would be able to opt-out of the rate if they so desire, just like they would in any full-scale rollout. The opt-out decision would be made either at the beginning of the pilot or after a certain number of months have elapsed. This is an important implementation detail that needs further thinking and development. SPP would thus generate data on customer opt-out rates, by type of rate, in addition to generating estimates of price elasticities, thus addressing two of they key uncertainties in net-benefits.

In addition to the customers that are randomly selected from the general population, about 400 customers would be selected from the ongoing Smart Thermostat pilot that is being conducted in the SCE and SDG&E territories under AB 970. These customers have opted into the program, which provides them significant financial incentives in exchange for agreeing to raise their thermostat setting during critical peak periods by a few degrees. For these customers, the program structure would be changed so that the financial incentive is not given to them in the form of a cash payment, but is structured around a CPP-V price. While these customers do not constitute a random sample, and therefore analysis of their usage changes would not be generalizable to the population from which they have been drawn, such analysis would nevertheless provide unique insights about how voluntary customers respond to pricing incentives in the presence of enabling technology.

3.1.2.6 Sampling Plan

As shown in the Table 3-2, the proposed sampling plan is for a sample size of 2,575 customers across six segments. Four of the six segments are in the residential sector, and are designed to capture the variation in customer price response across the state's four major climate zones. Two of the segments are in the commercial sector, and differ in size.

Table 3-2. Sample Design of the Statewide Pricing Pilot

12/04/02

Track A: Random Sampling With Opt Out Design

	Control	CPP-F	CPP-F (Info)	CPP-V (SDG&E) [1]	Info Only [1]	TOU	Total	Cost
Residential								
Zone 1	50	120	0	0	0	30	200	
Zone 2	50	120	0	0	0	30	200	
Zone 3	50	120	0	150	100	30	450	
Zone 4	50	240	0	0	0	30	320	
Total	200	600	0	150	100	120	1170	
w/Opt Out	250	750	0	188	125	150	**1463**	**$3,796,875**
Commercial								
<20 kW	50	0	0	60	0	30	140	
>20 kW	50	0	0	80	0	30	160	
Total	100	0	0	140	0	60	300	
w/Opt Out	125	0	0	175	0	0	**375**	**$1,300,000**
All Sectors								
Total	300	600	0	290	100	180	1,470	
w/Opt Out	375	750	0	363	125	150	**1,838**	**$5,096,875**

Tracks B: SF Cooperative

Residential	Control	CPP-F	CPP-F (Info)	CPP-V (SDG&E)	Info Only	TOU	Total	Cost
PG&E [2]	0	100	100	0	0	0	200	
Total	0	100	100	0	0	0	200	
w/Opt Out	0	125	125	0	0	0	**250**	**$625,000**

Track C: AB 970 Sub-Sample

Residential	Control	CPP-F	CPP-F (Info)	CPP-V (SDG&E)	Info Only	TOU	Total	Cost
SDG&E [3]	50	0	0	100	0	0	150	
Total	50	0	0	100	0	0	150	
w/Opt Out	62.5	0	0	125	0	0	**188**	**$468,750**
Commercial	**Control (SCE)**	**CPP-F**	**CPP-F (Info)**	**CPP-V (SCE)**	**Info Only**	**TOU**	**Total**	**Cost**
<20 kW	50	0	0	60	0	0	110	
>20 kW	50	0	0	80	0	0	130	
Total	100	0	0	140	0	0	240	
w/Opt Out	125	0	0	175	0	0	**300**	**$900,000**
All Sectors								
Total	150	0	0	240	0	0	390	
w/Opt Out	188	0	0	300	0	0	**488**	**$1,368,750**

SUMMARY

	Control	CPP-F	CPP-F (Info)	CPP-V (SDG&E)	Info Only	TOU	Total	Cost
Total Sample Size	**450**	**700**	**100**	**530**	**100**	**180**	**2,060**	
Total Sample Size with Opt Out	**563**	**875**	**125**	**663**	**125**	**150**	**2,575**	
Total Variable Cost								**$7,090,625**
Total Fixed Cost [4]								**$2,500,000**
Grand Total								**$9,590,625**

Notes:

(1) Entries are to be spread across various climate zones.

(2) This row corresponds to a proposal made by the San Francisco Cooperative and will be based on an opt out random sample located in the Hunter's Point/Potrero Hill districts of San Francisco and West Oakland/Richmond.

(3) These customers will be selected on an opt-out basis from the existing AB970 sample, which has an opt-in structure.

(4) Total fixed cost includes:

0.80 million: Market Research
0.75 million: Impact Evaluations
0.65 million: Project management
0.30 million: Refinement of Treatments and Sample Design

The sample size net of an estimated opt-out rate of 20% is 2060. Of these, about 1,500 will be selected through a stratified random sample on a statewide basis, and are designed to provide statewide price elasticity estimates for TOU rates and CPP-F and CPP-V rates. Another 200 will be selected through a stratified random sample in the San Francisco area, and are designed to measure the effects of information and CPP-F pricing in a community setting. Finally, 390 will be selected from the existing population of customers who have opted into the AB 970 program featuring smart thermostats. In the summer of 2002, CEC staff had identified the possibility of piggybacking off of an existing demonstration of smart thermostats in the small commercial and residential sectors to measure customer response to dynamic rates and comfort level with the smart thermostat control technology. This proposal has been incorporated into the SPP. One hundred and fifty residential customers located in SDG&E's service area will be included in SPP, and 240 commercial customers located in SCE's service area. By including these 390 customers in the sample, SPP leverages ongoing demand response programs, and increases the probability of scoring a "quick win" in the summer of 2003, as suggested by the Policy Working Group. In addition, customers opting out would be metered to determine if there are any systematic differences in their usage as compared to customers remaining on the tariffs.

Given the emphasis of the OIR on dynamic pricing, three-quarters of the customers have been allocated to the CPP-F and CPP-V rates. A total of 800 customers have been allocated to the CPP-F rate (inclusive of the customers in the San Francisco Cooperative area) and 580 customers to the CPP-V rate. TOU rates will be placed on 180 customers and 100 customers will be given information only. The rest would be in control groups.

Methodology

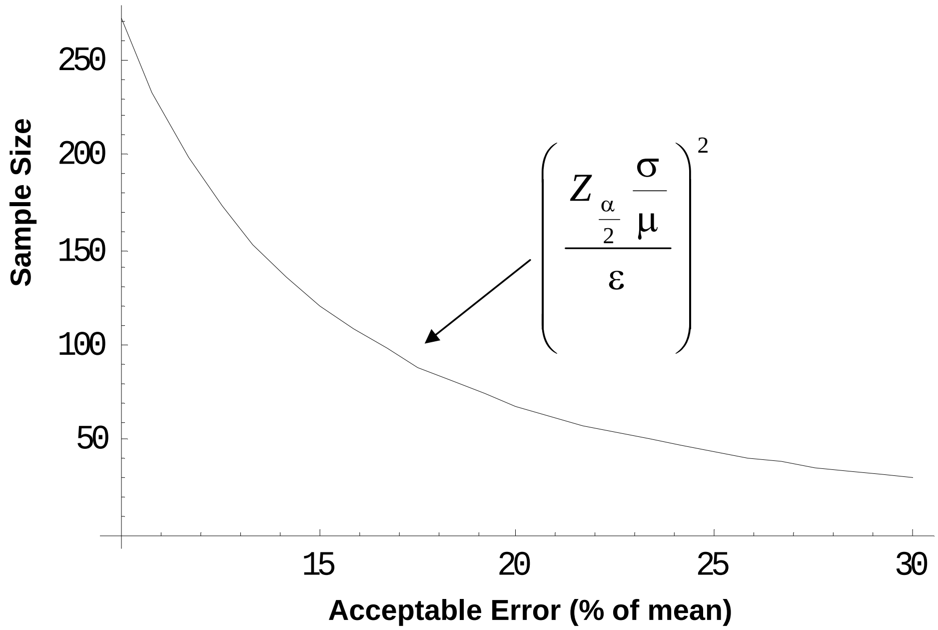
There are two primary approaches to developing a sample. In the first approach, based on classical statistics, the size of each treatment and control group cell is determined analytically, using information on the population mean and variance, the desired level of confidence in the results, and the acceptable level of precision. **Figure 3-1** provides an illustration of how sample size depends on the desired precision level.

This approach is widely used in cost-of-service studies to estimate the coincident peak demand for a class of customers. It has also been used in analysis of variance studies that seek to estimate the change in coincident peak demand associated with TOU pricing. However, it has not been widely used in estimating price elasticities of demand.

The main limitation of this approach is that it does not explicitly factor in the value of information coming from the sample and its impact on a key policy decision. The key policy decision to be addressed by policy makers is whether or not to proceed with full-scale implementation of dynamic pricing. Using Bayesian statistics and the tools of Decision Analysis, the sample size can be estimated using prior knowledge on the net-benefits associated with dynamic pricing.[24] This approach is described in the remainder of this section.

[24] *Applied Statistical Decision Theory* by Howard Raiffa and Robert Schlaifer, MIT Press, 1961.

Figure 3-1. How Accurate is "Accurate Enough"



Curve assumes 90% confidence interval and std. dev/mean ratio of 1

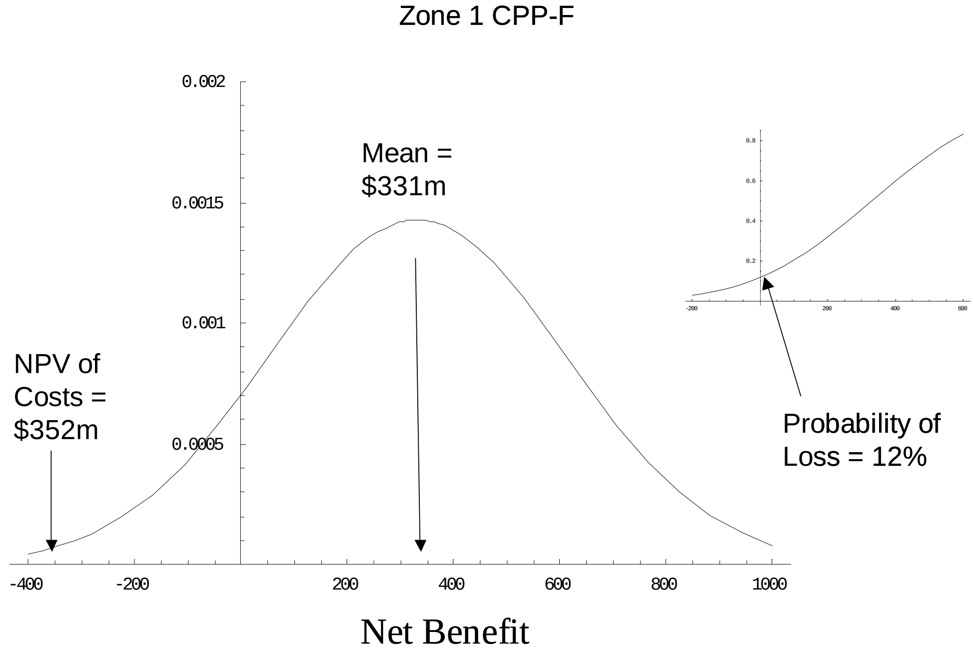
To place the approach in perspective, it is useful to recall that prior to the sample being drawn, there is a wide range in the estimated net benefits of dynamic pricing, as seen in the PG&E case study described in Section 4. In one of the climate zones, CPP-F has an expected net-benefit of $331 million, but there is a 12% probability that the program would generate negative net benefits, as shown in **Figure 3-2**.

Thus, there is a reasonable probability that the state will make the wrong decision in the absence of better information. It may proceed to implement dynamic pricing when it is not warranted, thereby incurring costs in excess of a billion dollars associated with deploying automated metering infrastructure. Or it may chose to stay with the status quo, thereby denying Californians the benefits of dynamic pricing.

A properly drawn sample should improve the probability of making a correct decision on full-scale implementation of dynamic pricing. This involves three major steps:

- Estimate the net benefits from implementing dynamic pricing for each of the treatments that look promising based on *a priori* information
- Estimate the costs of implementing each treatment during the sampling phase of the study
- Draw the sample to maximize the probability of making the right decision, taking into account the tradeoff between value of information and cost of sampling.

Figure 3-2. Pre-Sample Distribution of Net Benefits



The estimation of net benefits involves a computation of benefits and a computation of costs, usually as discounted present values over a planning horizon of 15 years.[25] Benefits are estimated from the following equation:

Benefits = (Existing usage per customer x Percent change in price x price elasticity) x Number of participants

Costs are estimated from the following equation:

Costs = Unit cost per participant x Number of participants

Both calculations involve several variables that cannot be predicted with certainty, and are best modeled in probabilistic terms. Monte Carlo simulation was used to develop the appropriate probability distributions.

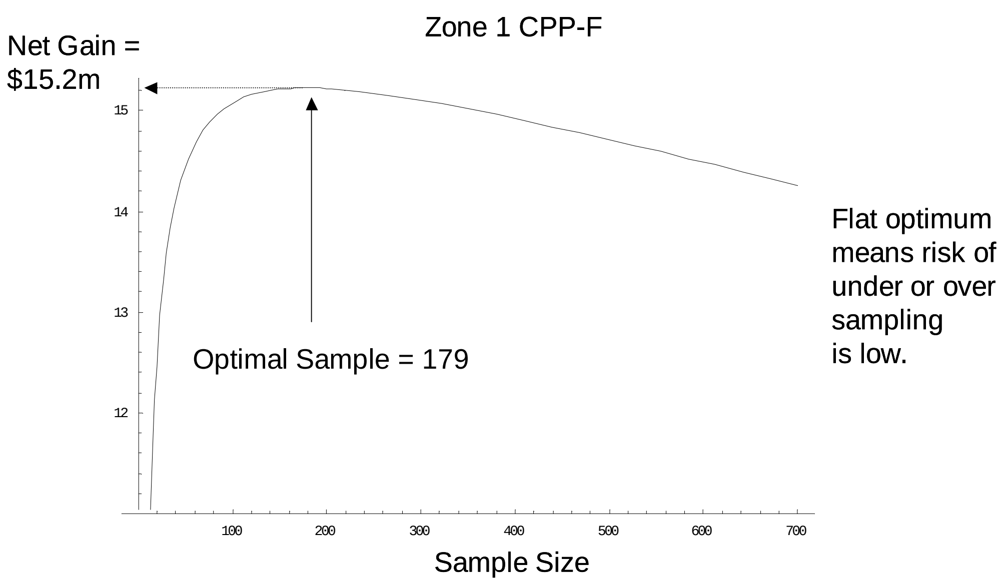
With the Bayesian approach, the following sampling outcomes are possible. If Treatment A is likely to generate greater net-benefits compared to Treatment B, but there is significant uncertainty in that result, the Bayesian approach would recommend drawing a larger sample than if there is no uncertainty in the result. I.e., if A will always be better than B, then sampling does not impact the final policy decision and contains very little useful information. The Bayesian approach explicitly factors the value of information into the determination of the optimal sample size for each treatment cell. It differs from

[25] It is important to note that while estimated cost-effectiveness of each sample cell is used in determining the optimal experimental design, this cost-effectiveness estimate in no way prejudges the ultimate cost-effectiveness results following implementation of the pilot and based on those experimental results.

the classical statistics approach where value of information does not play any explicit role in determining the sample size. The two approaches would give similar results if the prior information on net-benefits were very diffused or uncertain. The more sharply focused the prior information, the more the two sampling approaches will differ.

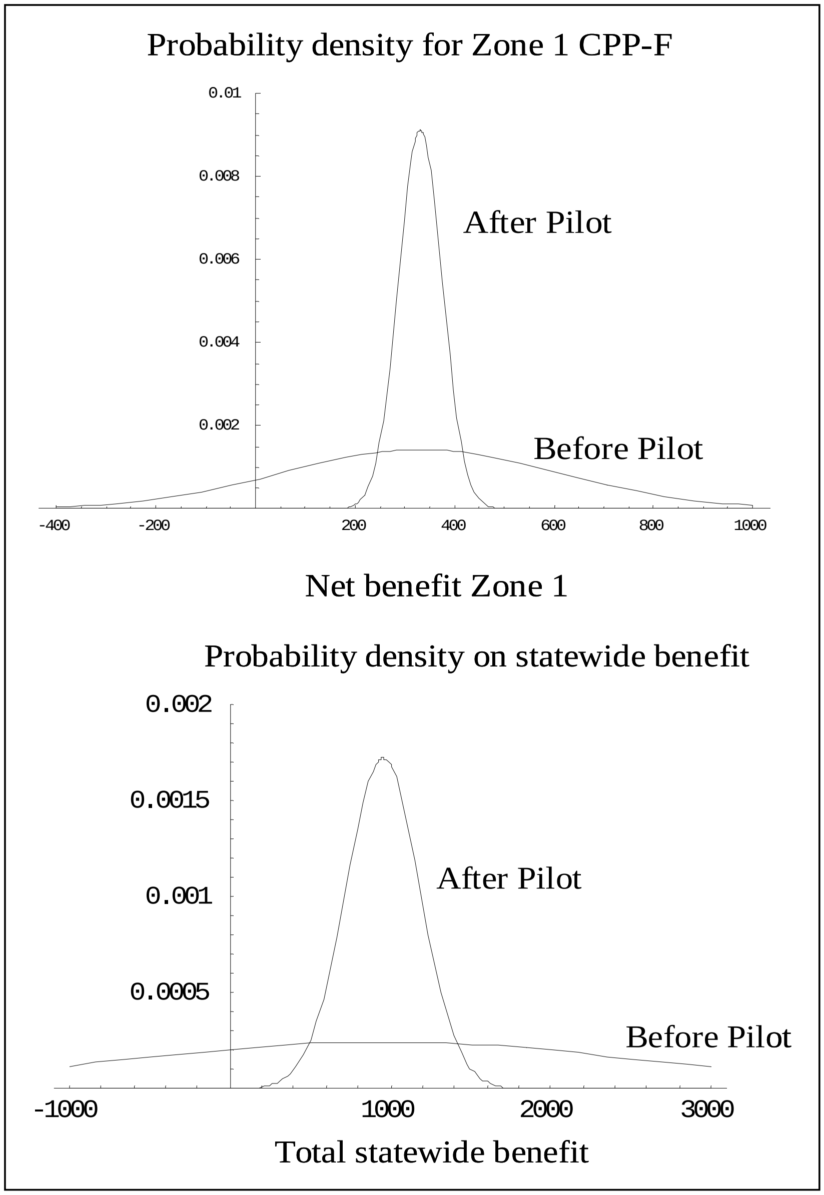
The Bayesian process was implemented using information from the PG&E analysis of net-benefits, scaled up to reflect statewide conditions, and information on the cost of sampling various treatments as well as the cost of full-scale implementation. The net gain from sampling as a function of sample size is shown in **Figure 3-3** below for Zone 1 (hot climate) with CPP-F. The curve rises steeply until a sample size of 50 is reached, and then increases at a decreasing rate. The maximum is reached at a sample size of 179, which would yield a net gain of $15.2 million. In other words, a sample size of 179 would maximize the net benefits of information being generated by the sample. Once the optimal sample size is reached, the net gain curve flattens out, with a small negative slope. The flat shape of the optimal sampling curve means that one can factor in non-economic objectives such as equity and equal coverage without sacrificing much economic value in the process. For logistical and budgetary reasons, the SPP proposes using a smaller sample size of 119, which would sacrifice a net gain of only $0.1 million.

Figure 3-3. Optimal Sample Size



In aggregate terms, the proposed sample design will have a net gain of $225 million. The primary benefit of sampling is that it will narrow the prior probability distribution on net-benefits. This effect is shown in **Figure 3-4**, where the top panel shows the effects for Zone 1 and the bottom panel shows the effects for the state as a whole.

Figure 3-4. Narrowing of Uncertainty Due to Sampling



The SPP sample is based on a combination of factors, including the results of the Bayesian approach, the interests and issues raised by other parties, and practical considerations about timing and budget.

3.1.2.7 Pilot Duration And Timing

As indicated in Section 3.1, the goal is to implement SPP prior to June 1, 2003. This is an ambitious but achievable schedule. SPP will run for a minimum of 16 months, through the summer of 2004 (subject to the caveat discussed in the following paragraph). This duration will allow impact estimates to be determined for two summers and also an assessment of whether customer response increases or decreases the longer participants are on the rates. It will also allow for development of demand response estimates for all seasons.

The three IOUs will give priority to installing the necessary metering for customers with existing smart thermostats to ensure that these customers will be ready by June 1, 2002 to receive time-varying tariffs, if for some reason the other customers are not.

Importantly, initial response estimates will be developed in the fall of 2003, covering the first of the two summer periods. If results from this initial assessment are conclusive (e.g., they show unequivocally that the benefits of customer responsiveness are sufficient to offset incremental costs), or they suggest a need for alternations in the pilot design, the pilot could be terminated prior to the summer of 2004, or it could be modified.

The keen desire of the Policy Working Group to implement the pilot by the summer of 2003 does not allow sufficient time to collect pre-treatment interval data on all pilot participants. However, with careful selection of control groups, and the fact that some of the most important factors such as weather anomalies that can be controlled for using pre- and post-treatment data can also be adjusted for by including the relevant variables in the regression analysis, there is a high probability that statistically valid results will be obtained with the current design.

3.1.2.8 Evaluation Plan

The primary objective of the evaluation plan is to determine the extent to which customers respond to time-varying prices, in the presence and absence of complementary information and technology treatments, and to assess how responsiveness varies with customer characteristics, weather and other determining factors. The pilot will also provide insights into customer opt-out rates.

Customer responsiveness will be determined by estimating demand equations, which relate usage by time period to rate types and price levels, other experimental treatments, customer characteristics, and weather conditions. The primary data requirements for such an analysis include (a) measurements of customer load shapes; (b) measurements of customer socio-demographic and economic characteristics; (c) price and other treatment effects; and (c) weather conditions. Customer load shapes will be obtained from the advanced metering equipment that will be installed on all customer premises. Socio-demographic and economic information for each customer will be gathered through surveys of each participating customer conducted at the beginning of the experiment. Relevant characteristics include dwelling type; age of dwelling; size of dwelling; saturation of major electric appliances; number of people in the house; age of the head of household; and average income. It will be very important to employ survey methods that ensure a very high response rate (in excess of 90%), since only observations with complete information can be used in the regression analysis.

One of the issues that will be determined through the evaluation process is the best functional form for the demand equations. A variety of functional forms have been used in the literature. By far the most commonly used form is the double-logarithmic (double-log) form. Other forms include the Constant Elasticity of Substitution form, the Generalized Leontief form, and the Quadratic Functional form.

In the double-log form, the coefficients on the price terms are the price elasticities of demand, and can be directly read off the estimation printouts. In addition, the equations can be estimated through a commonly used regression technique, ordinary least squares.

Using this functional form, the natural logarithm of electricity usage is expressed as a function of the natural logarithm of all the on-peak and off-peak prices, and all the other variables such as socio-demographic and economic characteristics and weather. This functional form has the advantage of instantly yielding the price elasticities of demand. For example, the coefficient of the peak-period price in the equation for peak period usage is the own-price elasticity of demand for on-peak usage, and the coefficient of the off-peak price in the same equation is the cross-price elasticity between on-peak usage and off-peak price.

With the logarithmic functional form, all own-price and cross-price elasticities are constant across various price levels. Some analysts find this fact disconcerting, citing anecdotal evidence that price elasticities vary with the level of price. At very low prices, customers do not respond to price changes. At very high levels, they have exhausted their ability to respond. Most of the "average" response occurs at moderate price levels. The logarithmic functional form can be modified to capture such non-linearities in customer response to price changes. The easiest way to accomplish this is to introduce cross-product variables on the right hand side, consisting of the product of the various price terms and the socio-demographic, economic and weather terms.

An example of the double-log form was presented in Section 3.1.2. Such equations would be estimated for each time period, resulting in the estimation of a system of demand equations. For example, a two-part TOU rate would result in a two-equation demand system. An issue that would need to be resolved is whether a separate demand system should be estimated for each of the different rate structures that are considered in the pilot (e.g., 2-part TOU and two-part TOU with CPP-F), or a combined demand system that pools the data across both rate structures. Pooling the data would maximize the efficiency of the statistical estimation process. Of course, a Chi-squared statistical test based on comparisons of the log-likelihood in the alternative model specifications would need to be conducted to see if the estimated parameters are the same across the two rate structures. If the hypothesis of same parameters were rejected, then we would estimate separate models for each rate structure.

The unit of analysis will be kWh usage by time period. The analysis can be performed either on daily, weekly or monthly data. Daily data is preferable since the CPP price signals are day-specific and daily usage provides greater variation in weather conditions and, therefore, greater precision in the all-important weather parameters. The demand estimation will be based on observations for individual customers. A key result from the estimation process will be the set of own-price and cross-price elasticities of electricity usage. Another key result will be an estimate of the total usage impact.

One issue that requires further discussion is the estimation of coincident kW demand impacts. An auxiliary regression model would be estimated that relates changes in coincident kW demand to changes in on-peak period kWh usage. The regression analysis would allow the assessment of whether the relationship is linear or non-linear, and continuous or discontinuous.

Once the demand systems have been estimated, they will provide the ability to predict demand and usage impacts by utility service area, given the customer and climatic conditions of each utility as well as the level and type of existing rate. Such analysis would be done for a wide range of time-varying rates, and given the avoided commodity and T&D costs facing each utility, would yield estimates of the gross benefits of implementing time-varying pricing. This information would then be used by each company to determine whether it is cost-effective to install advanced metering systems in its service area.

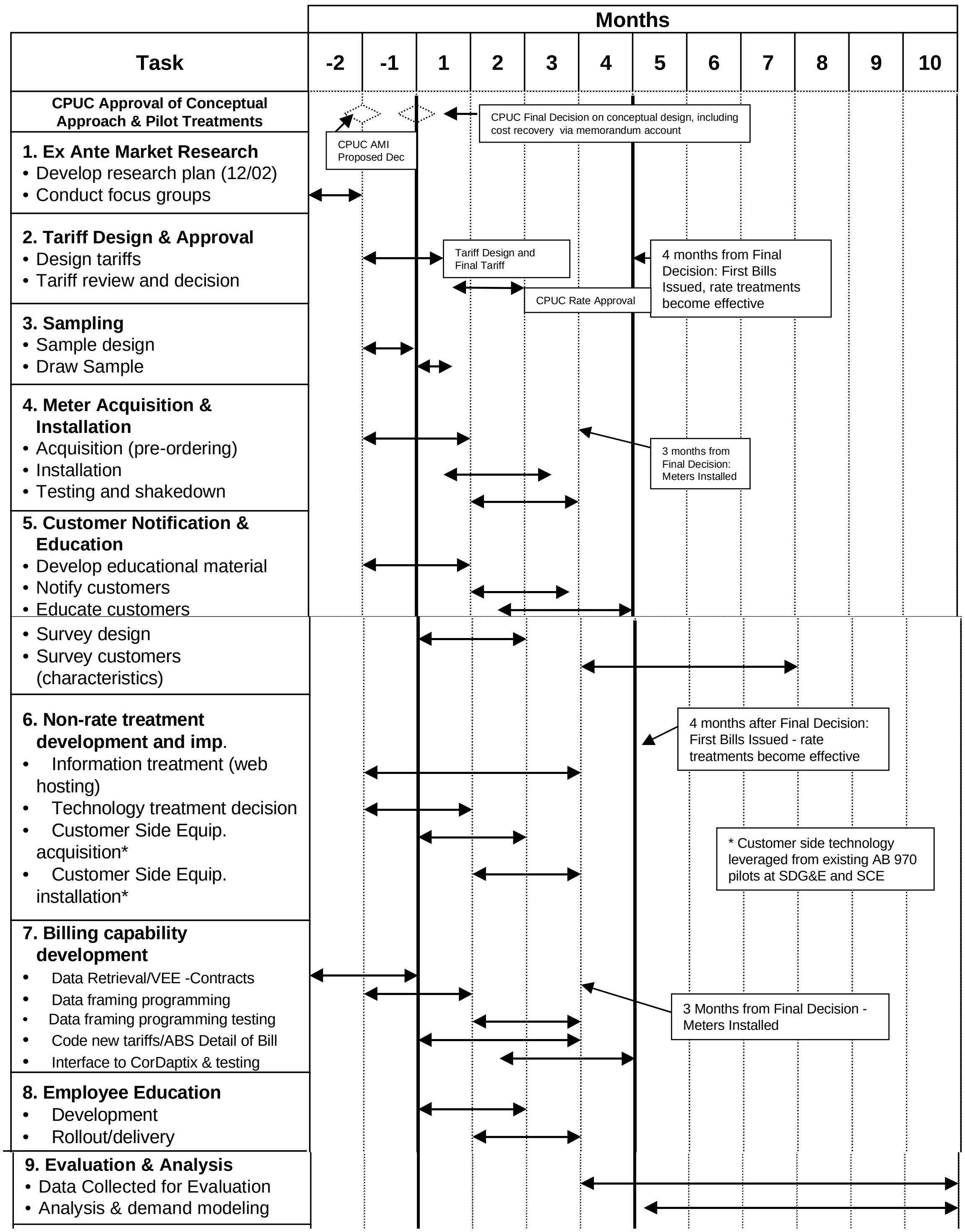
Implementation Plan and Schedule

A substantial amount of work will be required over the next several months in order to successfully implement the SPP, including:

- Completion of the conceptual design
- Obtaining commission approval for the conceptual approach and timeline, and for cost recovery
- Finalization of the tariff design and obtaining commission approval of the experimental rates
- Completion of the sampling plan and drawing the sample
- Designing and implementing the customer contact plan (notification of meter installation, pilot enrollment, etc.)
- Acquiring and installing meters
- Implementing customer education and notifying customers of their participation in the pilot
- Developing and implementing customer surveys
- Developing and implementing the non-rate treatments
- Developing and implementing data retrieval, data framing and billing capabilities;
- Employee education; and
- Conducting the evaluation and analysis of the data, which will occur in multiple stages throughout the pilot.

Figure 3-5 illustrates the approximate order and timing of these tasks.

Figure 3-5. SPP Schedule



Pilot Costs

The costs associated with SPP will be significant. Implementation costs involve the following categories:

- Project management
- Customer education
- Customer notification and contact tracking system
- Meter hardware and installation
- Meter reading and communication
- Data retrieval, validation and management
- Billing system interface development and implementation, including data framing and preparation
- Information treatment
- Enabling technology treatment.
- In addition, there are a wide variety of planning and evaluation activities that must be covered by pilot funding, including:
- Conceptual design and rate pre-screening
- Design of customer notification and contact plan, including development of materials
- Development of specific prices and other treatment effects
- Evaluation plan development
- Detailed implementation planning
- Design and implementation of customer characteristics survey
- Design and implementation of customer preference and customer satisfaction surveys
- Behavioral research
- Econometric estimation of price elasticities.

Some of these cost categories are largely fixed while others are primarily variable. Initial estimates are that the average variable cost will equal roughly $2,500 for each residential pilot participant and about $3,000 for each commercial participant. The breakdown of these costs for residential participants is shown in **Table 3-3**.

Table 3-3. SPP Costs, per Participant

Cost Category	**Average Cost Per Participant**
Up-front communicating interval meter purchase and installation, including communication set-up	$1,100
Data retrieval, storage, validation and presentment costs ($25-$35/month, for 12months)	$400
Billing data preparation and billing system interfaces ($920k for both up front systems costs and first year ongoing costs to frame data for 1,500-1,800 meters)	$600
Customer selection, recruitment, education and support (costs divided over number of installed meters)	$400

It is estimated that such activities will cost an additional $500 per commercial customer.

The fixed costs of SPP are estimated at $2.5 million. These are comprised of $800,000 for market research activities of three kinds that are discussed further in Section 3.1.4; $300,000 for refinement of the sample design and rate, information and technology treatments; $750,000 for impact evaluation activities, including econometric analysis of daily usage data by time period, resulting in a full-set of price elasticities of demand for the six market segments and three rate types; and $650,000 for project management activities at the three IOUs.

3.1.3 Principles of Experimental Design[26]

The SPP design is based on scientific principles of experimental design. One of the requirements that the pilot must fulfill is to allow estimates of usage impacts to be developed not just for the rate (and information and technology) treatments that are used in the pilot, but also for all plausible values of future rates that may be implemented during the next decade. Many pilot programs are simply focused on estimating customer response to a specific rate or technology treatment. For example, Puget Sound Energy's TOU pilot program features a single rate and information treatment. In order to support rate policy and business planning

[26] For a summary of the key issues, see D. J. Aigner and C. N. Morris, **Experimental Design in Econometrics**, Annals of Applied Econometrics 1979-2, A Supplement to the Journal of Econometrics, Volume 11, and No. 1, September 1979.

across the three utilities, the pilot (or set of pilots) must allow policy makers to extrapolate beyond the rates and treatments that are explicitly tested in the pilot.

Thus, the pilot must be designed to:

- Estimate the relative impact on usage of different rate structures and treatment options
- Develop own and cross-price elasticities for usage and peak demand as a function of population characteristics
- Allow estimation of the impact of prices not included in pilot

It is essential that the pilot design be able to capture not only the response of the average customer to various forms of time-varying rates, but the variation in response across customer types and climate zones. This is especially important for a state like California where there is considerable variety in climatic conditions and the socio-demographic condition of customers. Prior research conducted by EPRI, using a pooled data set that included data on customer response from California, Connecticut, North Carolina and Wisconsin, indicates that customer responsiveness varies significantly with appliance ownership and climate.[27] For customers living in a hot climate, who had all major electric appliances in their home, measures of customer responsiveness were more than twice the value for those living in cool climates without any major electric appliances in the home.

Given the long history of experimentation in the social sciences, it is possible to identify common errors in experimental design that invalidate the conclusions that one would otherwise draw from these experiments. Two conditions render an experiment invalid: lack of internal validity and lack of external validity. A pilot is invalid internally if it fails to establish a cause-effect relationship between the treatments considered in the pilot and the outcomes measured for the participants who were given the treatments. Threats to internal validity can be controlled by scientific design. A pilot is invalid externally if its findings cannot be applied outside of the pilot setting, to other populations of interest or during other time periods for the pilot's population. Thus, the pilot conducted by EDF with its *tempo* rate yielded price elasticities that were much higher than those found in any American study.[28] Those elasticities reflect the unique culture and history of France, and may well be valid for France and possibly neighboring European countries. However, without further analysis, they may not be transferable across the Atlantic.

It is possible to enhance the external validity of a pilot by taking a number of steps. For example, by including a variety of rate treatments in the pilot that span a range of future market conditions and not just the conditions in today's market, one can ensure that the

[27] EPRI Research Project RP-1956.

results would be valid in the future. In addition, by measuring the effect of socio-demographic and climatic factors that vary across regions, one can assure that the results will be valid not just for the customers included in the pilot but to the entire target population. However, it is not possible to guarantee external validity, since unusual weather or economic conditions can be encountered during the implementation of any pilot program.

The remainder of this discussion focuses on how to ensure a pilot's internal validity. There are ten common design flaws that render a pilot invalid internally.

1. A pilot may not have a control group. It may only have customers in one or more treatment groups. In this instance, their usage is observed before and after the treatment has been administered, and the entire change in usage is attributed to the treatments being given. But some of the change in usage may have been due to factors other than the treatment. A control group provides a way to control for this effect, and its absence guarantees that the experimental findings will be plagued by doubt and ambiguity.

2. A control group may exist, but it may not be comparable to the treatment group. Thus, prior to the treatments being administered, usage between the treatment and control groups may diverge. Any divergence after the treatments have been administered would be confounded with the a priori divergence, creating imprecision in the estimated impact. Such experiments are called quasi-experiments.

3. The samples that are selected for the experiment may not be selected through random sampling methods. In this instance, it then becomes difficult to generalize the results to the intended population with any degree of confidence, since probability weights are absent.

4. The design may not allow for the measurement of pre-treatment usage. It would then become difficult to eliminate the effects of weather and other "confounding" variables that may have changed over time.

5. The pilot may feature an insufficient number of treatments. For example, it may just feature a TOU rate. This would mean that the pilot would yield price elasticities that are valid for TOU rates but may or may not be valid for other time-differentiated rates, or it might have a single price treatment, in which case one would not be able to extrapolate beyond the specific treatment tested.

6. The pilot may have insufficient sample size by treatment. This would lead to high variances in the estimated price elasticity estimates, and may render them useless for policymaking.

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[28] Christopher Aubin, Denis Fougere, Emmanuel Husson and Marc Ivaldi, "Real-Time Pricing of Electricity for Residential Customers: Econometric Analysis of an Experiment," **Journal of Applied Econometrics**, 10, 1995.

7. The pilot may have insufficient price variation within the various rate structures. It would then be unable to statistically identify own-price from cross-price effects.

8. The pilot may feature voluntary recruitment of participants, and fall into the category of being an "opt-in" pilot. Customers who choose to participate in the pilot may not be representative of the population of customers, being those who stand to gain from the pilot by either having different baseline load shapes or more price-elastic preferences. The estimated price elasticities would be tainted by "self-selection" bias. While collecting additional data and modeling can mitigate this bias, it is very difficult to guarantee that it will be completely eliminated.

9. Participants may be given compensatory payments to make them whole, i.e., to insulate them from any adverse economic impacts that may be caused by the experimental rates. If participants are aware that they will be made whole, they may behave differently than they would otherwise. If the payments are tied closely to the price of electricity, that may introduce bias in the estimated price elasticities as well.

10. The participants may behave differently simply because they are being observed. Known as the Hawthorne effect, this influence can be very difficult to expunge. Those who are getting the treatments would display a response during the experiment that would not match the response during a non-experimental application.

The best way to avoid these ten common mistakes is to use an experimental design that features a control and treatment group, and to take measurements before and after the treatments have been administered. Participants should be randomly selected to be part of the pilot, and then assigned randomly to the various treatment and control group cells. Only in cases where participants can show evidence of significant hardship should they be allowed to opt out of an experiment. Such a design, often dubbed the "gold standard," is shown in **Figure 3-6**.

The true measure of the impact of a treatment is the difference in usage of the treatment group before and after the treatment has been administered, net of any difference in usage of the control group during the same time period. This measure is labeled (T2-T1)-(C2-C1) in Figure 3-6. It can also be rewritten as (T2-C2)-(T1-C1). If the treatment and control groups are perfectly balanced, there is a good chance that T1-C1 will be zero. Then T2-C2 would provide a reliable impact of program impacts.

Figure 3-6. The "Gold Standard" of Pilot Design

	Control Group	Treatment Group
Before Treatment	C_1	T_1
After Treatment	C_2	T_2

I. True Impact Measure = $(T_2 - T_1) - (C_2 - C_1)$

– All other variables are held constant
– Random assignment to control or treatment group

II. Inferior Measures of Impact

– (1) $T_2 - T_1$
– (2) T_2
– (3) $T_2 - C_2$

While the "Gold Standard" provides the best way of measuring impacts, circumstances often force researchers to make compromises. For example, there may be no opportunity to collect data on the treatment group before treatments begin. i.e., T1 may not be available. In such cases, researchers would be forced to make some assumptions. For example, they could assume that (T1-C1) is zero, and simply rely on T2-C2 as a measure of the treatment effect.

3.1.4 Market Research

It is customary to precede pilot programs involving thousands of customers with a market research program to ensure that pilot treatments are understandable to customers, do not impose undue hardships, and are generally acceptable (e.g., are not "dead on arrival"). Market research can provide unique insights into customer needs and preferences, and it can help fine-tune the rate treatments that are offered in the pilot to customers. It can also determine the minimum amount of information that should be provided to customers, and the specific characteristics of enabling technology treatments that are offered to them.

If the products being tested in a pilot have no prior history, quantitative market research involving multivariate statistical analysis, conjoint analysis and/or discrete choice modeling may be warranted. Such research, which allows the analyst to get at customer willingness to pay for product features, takes a substantial amount of time and budget. A minimum amount of time for conducting a careful program of quantitative market research is four to six months. Such research is likely to cost between half a million to a million dollars.

On the other hand, if the products being offered have a prior history of implementation either in the geographic region where the pilot would be carried out or elsewhere, then it may not be cost-effective to conduct quantitative market research. Even if cost is not an issue, such market research should not be made a pre-requisite to conducting the pilot, since other researchers in prior pilots have already determined the feasibility of the products being tested. Under such conditions, it is appropriate to precede the pilot with some qualitative market research to ensure that no treatments will be offered to customers that would provoke a backlash, compromising the integrity of the pilot.

In the case of the Statewide Pricing Pilot (SPP), the products being tested are TOU and CPP-F and CPP-V pricing options. All three products have a history within the United States and Europe, as reported in Section 2 of this report. It is the intent of WG3 to have a pilot in the field by June 1, 2003, to comply with the expressed desires of the Policy Working Group. Given the lead-time in developing tariffs, choosing samples and installing meters and other enabling technologies, the window of opportunity for defining rate, information and technology treatments will close by the middle of February. Thus, WG3 proposes to conduct a limited amount of market research between mid-January and mid-February prior to the launch of the pilot. In addition, WG3 proposes to conduct additional market research in conjunction with the SPP and some research at the conclusion of the pilot. All three activities are briefly described below.

Participants in the WG3 process had different perspectives on the scope and timing of market research to gather data from customers on what they know and don't know about the new dynamic rates and about control technologies to be included in the statewide pilot. Some members argued for extensive market research that would need to be completed before SPP begins. Other members that placed a higher priority on starting SPP by June 1, 2003 suggested that the necessary market research could be limited in scope or duration to a few weeks to gather data on key issues related to tariff design and the control technologies to be offered.

Most of the WG3 members agreed that the delay associated with conducting extensive quantitative market research before launching the pilot was not worth the potential benefits of reducing the size and or cost of the proposed pilot design through additional market research.[29] Thus, WG3 proposes to conduct a limited amount of market research between mid-January and mid-February prior to the launch of the pilot. The remainder of the market research called for in the second, more comprehensive proposal would then be conducted concurrently with the implementation of the pilot. Thus WG3 proposes to conduct the

[29] Representatives of the CEC staff were not convinced of the need to limit the scope and depth of the market research because of the need to reduce the high level of uncertainty about what types of rates and technologies customers are likely to favor.

balance of the market research in conjunction with the SPP and some research at the conclusion of the SPP pilot. All three activities (recommended types of market research before, during and after the pilot) are briefly described below.

The following section presents the rationale for the more limited market research that could be completed before February 15th, 2003.

3.1.4.1 Ex Ante Market Research

Some of the key questions that need to be resolved prior to implementing the SPP are the following:

- How can the concept of time-varying pricing be best explained to customers?
- What features of TOU and CPP pricing appeal to customers?
- What features of TOU and CPP pricing do not appeal to them?
- What degree of dispatchability is desirable, with and without enabling technology?
- How can the TOU and CPP pricing options be designed to maximize customer acceptance?
- What should be the length, timing and number of peak periods?
- What combinations of peak and off-peak prices can customers cope with?
- Can customers respond to CPP pricing without enabling technologies?
- Is there any customer interest in day-ahead, hourly real time pricing?
- What information treatments are desirable/acceptable?
- What is the minimum information treatment that should be made available to all customers?
- What type of CPP notification procedures would be desirable/acceptable?
- How much time should be devoted to explaining the context of this experiment to participants? In other words, is it necessary to discuss questions such as: (a) why is there a need to send higher prices during critical peak periods; (b) is there a reasonable basis for sending such signals; (c) how can customers be sure this is not just another crazy scheme to raise prices?

Given the time constraints, the best way to address these questions is in a focus group setting. Each focus group session would comprise roughly a dozen customers, and would last for a couple of hours. A facilitator would explain the logic of time-varying pricing to the focus group members, and then walk them through a series of questions. It is feasible to hold half a dozen focus groups throughout the state between mid-January and mid-February.

This information would be used to fine-tune the rate options, eliminate any non-starters, and to help refine the specific rate, information and technology treatments that would be offered in the SPP.

3.1.4.2 Concurrent Market Research

Once SPP gets underway, there will be an opportunity to conduct additional market research. The results of this research would help improve the full-scale deployment of advanced metering and dynamic pricing options, if that is found to be cost-effective. They may also influence Phase II of the SPP, if a decision is made to continue the pilot for a second year. This research will be conducted on customers not participating in the pilot, since the pilot treatment of those customers is likely to affect their responses to market research questions

The quantitative market research would likely involve a conjoint survey and analysis in order to obtain insights on the following issues:

Rate Features

Market research would be conducted to determine what rate features are understood and valued by customers. For example, one possible rate feature is that the retail price is more expensive when wholesale prices are high. This concept can easily be understood and valued by customers.

Determine customer understanding and fairness measures of various rate features (e.g. relationship between retail price and wholesale cost or system conditions, relationship between demand response and monetary savings, relationship between appliance efficiency and monetary savings, and customer attitudes to current public disclosures concerning price and market manipulation in California energy markets)

Determine customer perceptions of and fairness measures for incentives involving fixed payments/penalties per kWh curtailed versus rate discounts/charges. Determine customer understanding and fairness measures for various combinations of features that define existing and potential new rate forms. At a minimum, the research would contrast flat, tiered, TOU, critical peak pricing and real-time pricing tariffs.

Information Treatments

- Identify customer needs for education and information.
- Identify critical versus supplemental information needs.
- Establish the willingness to pay for supplemental information.
- Determine critical differences between the need for information to support (1) notification versus (2) control.

Control Technology Treatments

- Identify customer needs, preferences and willingness to pay for technologies to adapt to dynamic tariffs.

- Identify critical versus supplemental technology needs
- Establish the willingness to pay for different control technologies, including simple, low-tech options such as timers on pumps for swimming pools and spas and inter-lock devices that prevent the simultaneous operation of two appliances; medium-tech devices such as receiver switches on air conditioners; and high-tech devices such as smart thermostats and Gateway systems that are always on.

Additionally, all participants would be surveyed to help in pilot monitoring and tracking.

Monitoring pilot implementation through customer perceptions is essential for adjusting treatments during the operating period to assure successful results, and avoid disastrous or destructive results. Standard survey techniques would be used to obtain this information.

Customer Perceptions

Market research should be conducted during and after the pilot test to measure customer understanding of and satisfaction with the pilot, determine problem areas, and remedy where possible. This would involve the conduct of surveys.

A variety of methods would be used during the concurrent phase of market research. These are briefly described below.[30,31]

- "Stated intent to purchase" survey. Customers are queried whether they would agree to switch to a new rate option. This technique produces rough estimates of market shares for specific rate options. It can be implemented quickly over the phone or the Internet.
- Stated value of product/service attributes. Customers are asked how much they value particular product attributes. For example, whether they would like a shorter or longer peak period. This technique provides input into product/service design but does not monetize attribute values or allow prediction of market shares.
- Conjoint surveys based on stated intent data. This is a fairly expensive technique that asks customers to rank various combinations of product and service attributes. It monetizes attribute values, and yields "willingness to pay" estimates for specific product features.
- Regression analysis of "stated intent" to purchase data. This technique allows prediction of market shares as function of attributes and customer characteristics. Its main limitation is that customers have not actually exercised their preference, and are dealing with a hypothetical situation, which they may or may not comprehend accurately.

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[30] For a discussion, see Lisa Wood, Suzanne Gambin and Patricia Garber, "Measuring How Customers Value Electricity Service Offers," in Ahmad Faruqui and Kelly Eakin (editors), **Pricing in Competitive Electricity Markets**, Kluwer Academic Publishing, 2000

[31] See, for example, Glen L. Urban and John R. Hauser, **Design and Marketing of New Products**, Prentice Hall, 1993 and Gary L. Lilien, Philip Kotler and K. Sridhar Moorthy, **Marketing Models**, Prentice Hall, 1992.

- Regression analysis of actual market purchases. This technique improves on the previous one, by analyzing actual rather than hypothetical purchase data. It is based on the concept of revealed (as opposed to stated) preference. It provides the most reliable estimates. The main limitation is that it can only be implemented ex post, and is of limited value when testing new product concepts.

3.1.4.3 Ex Post Market Research

All customers who have participated in the pilot would be surveyed at the end of the pilot to obtain their perceptions of the specific rate they were on. They would be asked what they liked about the rate and what they did not like about it. They would also be asked, now that they have experienced the rate, if they would like to continue on the rate. They would be asked similar questions about the information and technology treatments. Taken in conjunction with the results of the concurrent market research, this information would be yield insights that would be of great value in developing the pricing program that would be offered in the full-scale rollout.

3.1.4.4 Market Research Budget

The ex ante phase of market research involving half a dozen focus groups is estimated to cost $100,000. The concurrent market research, involving a variety of quantitative analytical methods, is estimated to cost between $500,000. The ex post market research is likely to cost about $ 200,000. Total costs of these market research activities are estimated at $800,000, and have been included in the fixed costs shown earlier in the Sample Design table.

3.1.5 Cost-Benefit Analysis of SPP

The real benefit of SPP is the improved decision making that results from conducting it. This flows from the value of information that it creates by narrowing the range of uncertainty in net benefits. Earlier in this section, this value has been estimated at $225 million, which is more than 20 times higher than the cost of the pilot of $9.6 million.

However, for completeness, the Policy Working Group has asked that WG3 perform a cost-benefit analysis of the peak load reductions caused by SPP. This involves the estimation of net benefits for the proposed sample design, and is unlikely to show positive net benefits since metering and communication costs are higher by an order of magnitude during the pilot phase of any full-scale implementation.

Benefits are estimated as the product of (a) predicted changes in energy use and peak demand and (b) marginal energy and capacity costs. Item (a) itself was estimated as the product of the (c) impacts per customer and (d) the number of customers. Item (c) was estimated from the product of the percent change in price, price elasticity of demand, and energy use and peak demand per customer.

The analysis retains the structure of that performed for Pacific Gas & Electric, while adapting certain assumptions to fit the conditions of the pilot. These include participation values and program costs, which were estimated by PG&E. The original elasticities, baseline load shapes, and prices are held constant at their existing PG&E values. Benefits, costs, and net benefits are presented as both annual values and 15-year net present values. Opt-out rates are 20% for both the CPP and TOU programs.

3.1.5.1 Program Costs

Sample costs were calculated by using a unit cost estimate of $2,500 per residential customer and $3,000 per commercial customer. These costs are an order of magnitude higher than the costs that would be realized in a full-scale implementation, and will adversely affect the cost-effectiveness of SPP. The variable CPP treatment groups have an additional cost of $750 per residential customer and $1,000 per commercial customer.

3.1.5.2 Avoided Costs

The analysis uses a set of marginal costs proposed by the CPUC for consideration by WG3. This set only provides peak avoided costs, so the CEC derived costs for the time periods have been used where there are no CPUC values. One year of data was provided, which was escalated over the 15-year time horizon. In addition, some variable O&M has been added to the avoided energy costs.

3.1.5.3 Results

SPP customers are predicted to lower their peak demand in the year 2003 by 1.5 MW, from a base level of 14.5 MW. This is projected to yield gross benefits of approximately $ 0.155 million and gross costs of $ 9.6 million, resulting in an annual net benefit of –$9.4 million dollars. If the customers are left on the new tariffs for a 15-year period, the net present value of benefits will increase to $ 2.01million and the costs will stay unchanged, yielding a net present value of benefits of –$7.6 million.

Details are contained in **Table 3-4** below.

Table 3-4. Details of the SPP Treatment Cells

Population Target	Segments	Rate Treatment	Participation	Information Treatments	Technology Treatments	# Participants After Opt Out	# Participants	Baseline kW (2003)	New kW (2003)	Change in kW (2003)	% Change in kW	Benefits (millions)	Costs (Millions)	Net Benefits (Millions)
Track A: Random Sampling With Opt Out														
Residential	Climate Zone 1 (R)	2 Period TOU	Opt-Out	No	No	30	38	66	62	4	-6.55%	0.0005	0.0938	-0.0933
		CPP-F	Opt-Out	No	No	120	150	265	176	88	-33.33%	0.0091	0.3750	-0.3659
		Control Group	N/A	No	No	50	63	110	110	0	0.00%	0.0000	0.1563	-0.1563
	Climate Zone 2 (S)	2 Period TOU	Opt-Out	No	No	30	38	70	65	5	-7.09%	0.0005	0.0938	-0.0932
		CPP-F	Opt-Out	No	No	120	150	282	188	94	-33.33%	0.0097	0.3750	-0.3653
		Control Group	N/A	No	No	50	63	117	117	0	0.00%	0.0000	0.1563	-0.1563
	Climate Zone 3 (T)	2 Period TOU	Opt-Out	No	No	30	38	16.3	15.8	1	-3.40%	0.0001	0.0938	-0.0937
		CPP-F	Opt-Out	No	No	120	150	65	49	17	-25.57%	0.0017	0.3750	-0.3733
		CPP-V	Opt-Out	No	Yes	150	188	82	61	21	-25.57%	0.0021	0.6094	-0.6072
		Information Only	Opt-Out	Yes	No	100	125	54	54	0	0.00%	0.0000	0.3148	-0.3148
		Control Group	N/A	No	No	50	63	54	54	0	0.00%	0.0000	0.1563	-0.1563
	Climate Zone 4 (X)	2 Period TOU	Opt-Out	No	No	30	38	38	37	1	-3.51%	0.00014	0.0938	-0.0936
		CPP-F	Opt-Out	No	No	240	300	305	224	80	-26.39%	0.0083	0.7500	-0.7417
		Control Group	N/A	No	No	50	63	38	38	0	0.00%	0.0000	0.1563	-0.1563
Commercial	<20kW	2 Period TOU	Opt-Out	No	No	30	38	106	103	4	-3.49%	0.0004	0.1125	-0.1121
		CPP-V	Opt-Out	No	Yes	60	75	213	194	18	-8.66%	0.0020	0.3000	-0.2980
		Control Group	N/A	No	No	50	63	177	177	0	0.00%	0.0000	0.1875	-0.1875
	>20kW	2 Period TOU	Opt-Out	No	No	30	38	1358	1315	42	-3.12%	0.0048	0.1125	-0.1077
		CPP-V	Opt-Out	No	Yes	80	100	3621	3122	498	-13.77%	0.0516	0.4000	-0.3484
		Control Group	N/A	No	No	50	63	2263	2263	0	0.00%	0.0000	0.1875	-0.1875
Track B: SF														
Residential	PG&E	CPP-F	Opt-Out	No	No	100	125	54	40	14	-25.57%	0.0014	0.3125	-0.3111
		CPP-F	Opt-Out	Yes	No	100	125	54	40	14	-25.57%	0.0014	0.3148	-0.3133
Track C: AB 970 Sub-														
Residential	SDG&E (Track C)	CPP-V	Opt-Out	No	No	100	125	220	147	73	-33.33%	0.0076	0.3125	-0.3049
		Control Group	N/A	No	No	50	63	110	110	0	0.00%	0.0000	0.1563	-0.1563
Commercial	SCE (<20kW) (Track C)	CPP-V	Opt-In	No	Yes	60	75	213	194	18	-8.66%	0.0020	0.2250	-0.2230
		Control Group	N/A	No	No	50	63	177	177	0	0.00%	0.0000	0.1875	-0.1875
Commercial	SCE (>20kW) (Track C)	CPP-V	Opt-In	No	Yes	80	100	3621	3122	498	-13.77%	0.0516	0.3000	-0.2484
		Control Group	N/A	No	No	50	63	2263	2263	0	0.00%	0.0000	0.1875	-0.1875
Track A Residential						1,170	1,463	1,563	1,252	311	-19.91%	0.0321	3.7991	-3.7671
Track A Commercial						300	375	7738	7175	563	-7.28%	0.0589	1.3000	-1.2411
Track A Total						1470	1838	9301	8427	874	-9.40%	0.0909	5.0991	-5.0082
Track B Total						200	250	109	81	28	-25.57%	0.0029	0.6273	-0.6244
Track C Residential						150	188	331	257	73	-22.22%	0.0076	0.4688	-0.4612
Track C Commercial						240	300	6274	5757	517	-8.24%	0.0536	0.9000	-0.8464
Track C Total						390	488	6605	6014	590	-8.94%	0.0612	1.3688	-1.3076
Total						2,060	2,575	16,015	14,522	1,492	-9.32%	0.1550	7.0951	-6.9401
Fixed Cost													2.5	
Grand Total						2,060	2,575	16,015	14,522	1,492	-9.32%	0.1550	9.5951	-9.4401

CPUC Scenario Avoided Costs (2003-2004 Average)		
Marginal Energy Costs ($/kWh)	**Summer**	**Winter**
Critical	0.0365	
On-Peak	0.0406	0.0336
Partial-Peak	0.0406	0.0344
Off-Peak	0.0263	0.0265
Marginal Capacity Cost ($/kW-year)	87.01	

3.2 Home Control Alternative Pilot Proposal

3.2.1 Statement of Pilot Size Justification and Need

An alternative pilot is proposed by Invensys Home Control Systems ("Invensys") to test the effectiveness of an advanced interactive technology treatment and Dispatchable Demand Response offerings.

Invensys sees this as possibly one of the best chances California has to set the stage for the future of demand side energy delivery. In submitting this turnkey alternative pilot proposal, Invensys respectfully suggests that, at minimum, California needs to test dispatchable demand response using interactive technology based on the belief that:

- Market research alone will be insufficient in determining the promise of advanced interactive technology in meeting the energy goals of the state
- The right approach with interactive control technology can simplify the consumer experience of a complex market;
- The state must also test programs that use a "carrot" rather than a "stick" to influence consumer behavior.

Thus, Invensys offers this turnkey pilot using its GoodWatts™ approach as a supplement to the SPP and as a replacement to a portion of the proposed market research.

This Pilot assumes that a subset of 20-35% of households in the state represent a target set that could represent substantial loads in a dispatchable demand response scenario. Invensys would target prospective customers within appropriate areas and would recruit qualified customers that have an HVAC load plus one other main load (pool, spa, water heat, pump)

This pilot is designed to achieve the following broad goals (in addition to those in the SPP):

- Determine consumer acceptance of an interactive dispatchable demand response program
- Determine the effectiveness of customer-defined automatic response to price points32
- Use interactive feedback to optimize program designs
- Determine the value of differing levels of communications and technology assisted enabling.

[32] Permit customers to define their own willingness to pay for energy at different price points, make adjustments to fit their requirements and monitor results.

3.2.2 Summary of Proposal (Option 1)

- 3,000 points (1,000 each in PG&E, SDG&E and SCE service areas) as a stand-alone supplemental program
- Test 37 participants per cell as follows: 3 climate zones, 3 social demographic segments, 3 marketing programs, 3 incentive treatments
- Turn-key program implementation by Invensys including recruitment, installation and operation
- Software program monitoring and "power-plant" interface for controlling entity
- Consumer access to their home control and energy information through a variety of easy-to-use interfaces.
- Cost per pilot point $1500 per point includes provisioning (customer recruitment and management, project management), two-way communication (always-on) gateway, revenue-grade metering to the home, controllable thermostat, and one additional sub-metered load, all operations and communications costs for 12 months
- The costs do not include additional program evaluation by a third party (stated by CRA as costing $1M to $3M per pilot.)
- Estimated average peak load reduction per qualified targeted home: 2.3 kW (to be verified in the test), resulting estimated cost effectiveness for the pilot $652 per kW[33], with estimated consumer churn rate of less than 2% per year.

3.2.3 Summary of Proposal (Option 2)

- 300 points (in one or two utility service areas) as cells added to the SPP program
- Test enabling technology treatment for a dispatchable incentive and a control group in 2 climate zones, with 50 participants per cell
- Turn key program implementation by Invensys including recruitment, installation and operation

Key differences from Option 1:

- Limited test of dispatchability; focus instead on supplementing tariff with technology treatment

[33] $1500 per home/2.3 KW per home = $652 per KW

- Cost per pilot point equivalent to the cost quoted in the SPP at $2500 per point includes provisioning (customer recruitment and management, project management), two-way communication (always-on) gateway, revenue-grade metering to the home, controllable thermostat, and one additional sub-metered load, all operations and communications costs for 8 months

The key differences in the Invensys proposal over the Joint Utility proposal are:

1. The testing of dispatchable Demand Response programs using a fully functional advanced technology platform.

2. The inclusion of additional load types over HVAC and a platform capable of later including appliance loads.

3.2.4 Design Principles

The principals used in the program and pilot design are as follows:

1. Pilot programs must be easily described and understood by customers.

2. Pilot programs should attempt to encourage customers to change by utilizing positive incentives versus negative economic impacts to accomplish their goal. Invensys Home Control Systems proposes leaving a flat tariff in place for program customers and rewarding load reduction and shifting by the consumer from On Peak periods to Off Peak periods using credits generated by avoided costs as the funding mechanism. This concept of using the “carrot” versus the “stick” has proven to be much more acceptable when implementing change on a mass scale.

3. Programs should strive to better understand and optimally use economically viable (communications and control) interactive systems technologies in their design to achieve maximum benefits with a high level of acceptance from the end use customer.

4. Mitigate or reduce apparent complexity through the use of thoughtful design and automated control to ensure their acceptance and long term success.

3.2.5 Rationale Supporting Sample Size

Invensys used the same rationale as the SPP in supporting its sample size with two key differences: (1) addition of cells testing dispatchable demand response and overall technology treatments and (2) assumption that program-sponsored equipment installation would occur in homes that qualify based upon a simple recruitment questionnaire.

3.2.6 Opt-in vs. Opt Out, and Pre-program Measurement

Pilot homes need to be identified and communicating metering and measurement devices installed on them to determine their usage and consumption patterns just prior to implementation of programs or tariffs. This can happen within the test period outlined below.

The Invensys proposal can accommodate both opt-out and opt-in programs.

Treatments to be evaluated, rates, info, enabling technologies

Invensys stresses the importance of timely feedback to the consumer and that at a minimum, daily if not multiple times per day updates are essential to their “comfort factor” that they are winning and in control. Invensys has found in it’s own tests a very high level of appreciation from customers for information about how they use energy.

Invensys recommends testing a program that offers a carrot for actual participation in place of the stick that is typically associated with the “rate treatments” proposed to date. Key features include:

- A standard rate structure for supply as it exists today with the consumer being paid an incentive for actual kWh of curtailed load on an occurrence-by-occurrence basis.
- No kW given up = no payment
- Override or opt out of occurrence = no payment
- It never costs customer anything, but they make money if they participate, the default is no change from the norm (today).
- Participation is automatically controlled & dispatched by the load serving entity and overrides are manually performed by the consumer at their will as defined by the tariff or program.

3.2.7 How Results Will Be Used in Phase 2 and Beyond

Invensys expects that the output of this test will result in information enabling the following decisions:

- The extent to which sponsored technology should be implemented as part of dispatchable demand response in California

- The role of technology in tariff-based demand response in California
- Optimal program designs and options
- The type and extent of programs required to meet state goals
    - The level of verifiable control to expect
    - The level of savings in $/kW and kWh of various approaches

3.2.8 Implementation Plan and Schedule

If the Invensys platform option and primary research objectives are included as part of the Joint Utility program numbers and evaluation design, then the following Joint Utility schedule would apply.

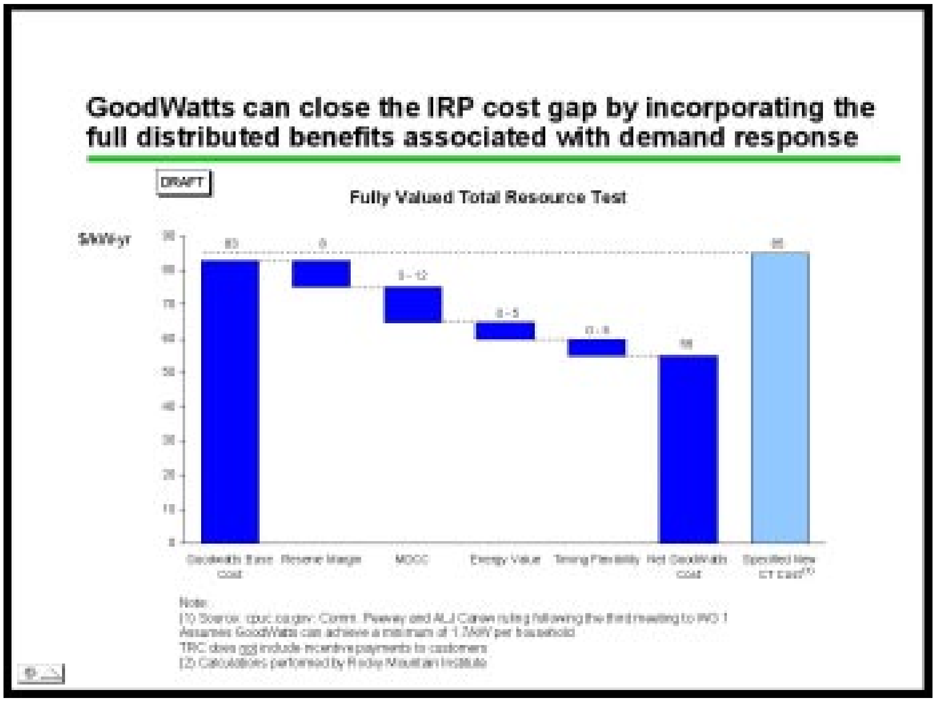
- Goal: devices installed, rates in place and data collection begins 6/03
- Evaluation and analysis completed 12/03

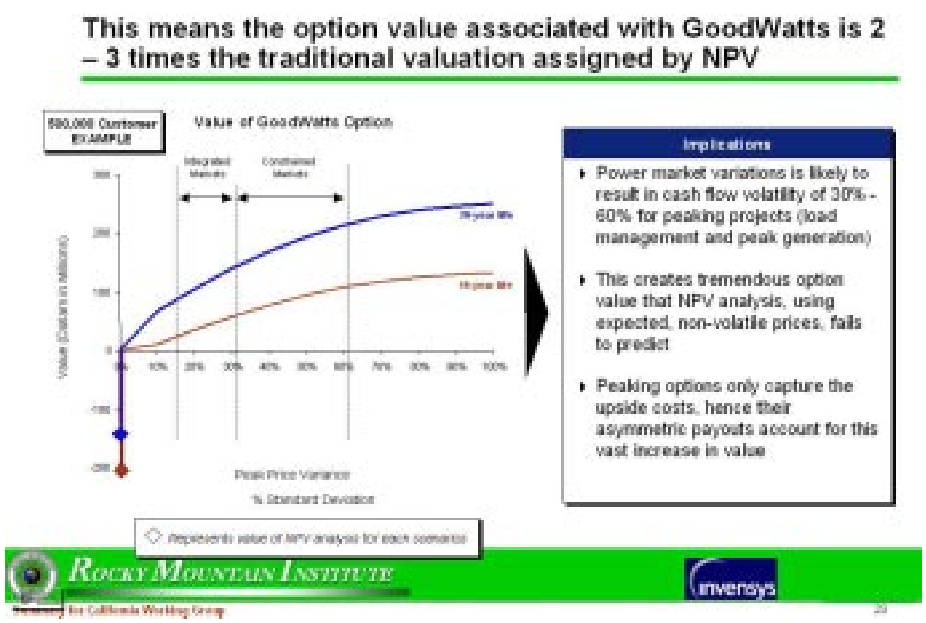
Note: A "Go" decision needs to be made by December for these deadlines to be met. Again, Invensys would manage recruitment, program management and customer payments in this pilot program.

3.2.9 Cost Effectiveness of the Proposal

We present two economic arguments here:

1. Fully Valued Least Cost Planning Economics (Total Resource Test)
2. Option Value vs. Uncertain Future Power Markets


GoodWatts can close the IRP cost gap by incorporating the full distributed benefits associated with demand response
DRAFT
Fully Valued Total Resource Test
$/kW-yr


This means the option value associated with GoodWatts is 2 – 3 times the traditional valuation assigned by NPV
Value of GoodWatts Option
Implications
Power market variations is likely to result in cash flow volatility of 30% - 60% for peaking projects (load management and peak generation)
This creates tremendous option value that NPV analysis, using expected, non-volatile prices, fails to predict
Peaking options only capture the upside costs, hence their asymmetric payouts account for this vast increase in value
Rocky Mountain Institute
invensys

Key Assumptions:

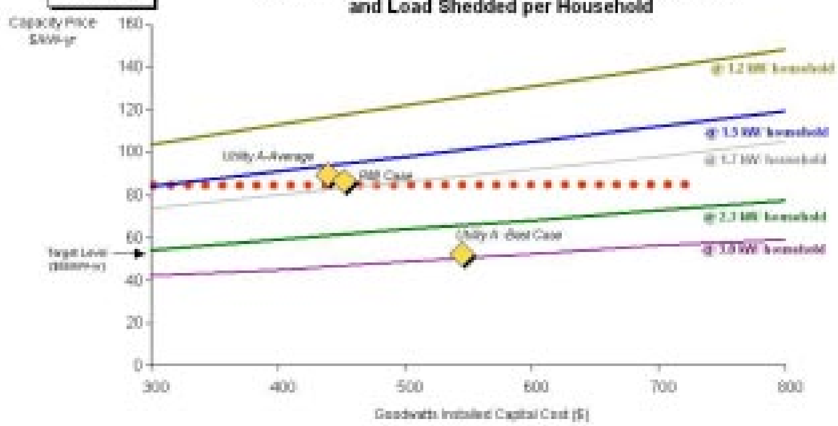
		Goodwatts	Gas CT	CC
Capacity Assumptions				
kW/ customer	KW	1.6 – 1.7	-	-
Equipment & Installation	$/customer	452	-	-
Customer Acquisition	$/customer	75	-	-
Installed Capital Cost	$/kW	310	430(1)	600(1)
Fixed O&M	$/kW-yr	51	9.8	16
PV Capital Cost	$/kW	792	523	752
Availability	%	90%	90%	90%
Coincident Peak	%	90%	100%	100%
Energy Assumptions				
Variable O&M	$/ MWh	20	2.2	1.1
Fuel Cost (levelized)	$ / MMBTU	-	4.40	4.40
Heat Rate	BTU / kW	-	10,600	6,700
Variable Cost	$ / MWh	20	48	31
Energy Shift	%	90%	-	-
Energy Reduction	%	10%	-	-

Notes: (1) Includes AFUDC and T&D upgrades
(2) PV Capital cost = Capital Cost + (Fixed O&M)/Crf
Capital Recover Factor for 20 years at 8.4% WACC is 10%

Considering capacity value alone, Goodwatts can have positive investment economics in some situations

ILLUSTRATIVE

Sensitivity of Capacity Prices to Installed Capital Cost and Load Shedded per Household



Note: Capacity Price $/kW-yr incorporates the fixed O&M costs of $86 per customer, and acquisition costs of $75 per customer

Caveat: the net kW/customer, based on the load diversity of the population, will determine the overall program efficacy

- If 500 houses reduce their on-peak demand by 2 kW, the savings are 1,000 kW...
- But, if 30% of the houses do not operate the controlled loads at that time, the savings are only 700 kW, or 1.4 kW/house
- Or, if the participating houses cycle the controlled loads 30% of the time during peak hours, the savings are only 700 kW, or 1.4 kW/house
- If 30% of of the houses do not operate the controlled loads, and the remaining houses cycle the controlled loads 30% of the time during peak hours, the savings are only 490 kW, or less than 1 kW/house!
- A 50% reduction in the saved kW/house means a 100% increase in the net $/kW cost!

These issues will be best resolved in a larger pilot

3.2.10 Summary

The overall success of the demand response will rest on the following factors:

1. Acceptance and willingness to participate by the customers.
2. The flexibility and adaptability of the system to change and continue to deliver necessary results into the future.
3. The ability of the tariffs, programs and systems to adequately measure, control and verify their designated actions and deliver desirable results.
4. Economic justification of all tariffs, programs and systems used.
5. Improved operational effectiveness on the energy delivery companies, systems and networks.
6. Flexibility in the tariff designs, programs and systems to meet the operational, geographic, climatic and demographic needs of the communities served now and in the future.

Overall, Invensys, through GoodWatts, proposes a complete test, a greater level of verifiable control than has been demonstrated with dispatchable technologies in the past, and greater savings for less $/kW and kWh. We believe that this test will result in greater cost effectiveness than other demand response approaches and will immensely increase program flexibility, providing both better information to evaluators and the ability to test a variety of innovative program designs without needing to revisit homes.

3.3 T&D Control Pilot Proposal

3.3.1 Overview of Proposal and Research Objectives

Peak energy constraints include generation (supply and costs), as well as capacity constraints on transmission and distribution systems. Constraints on the T&D system can be as serious as generation constraints.

Similar to energy efficiency programs, customers whether bundled or direct access, should they take action that produces positive affects on constrained T&D systems should receive reduced T&D charges regardless of whether they are bundled or direct access customers.

The IMServ pilot (T&D Control Pilot) will test the concept of providing incentives (based on T&D savings) for a combined integrated demand response/enabling technology and advanced metering open architecture solution directed towards reducing demand on constrained transmission and distribution systems (T&D).

The target market will primarily include direct access customers, with utility customers also eligible to participate. Utility customer participation will be managed by utilities.

The proposed pilot is not meant to replace other proposed pilots but is meant to compliment them by addressing areas not covered by others such as obtaining T&D benefits and expanding the population of eligible customers.

Customer participation in the proposed T&D peak constraint program would be voluntary with an opt-in/out provision. T&D credits for those customers who reduce T&D costs would be calculated by utilities and approved by the CPUC.

The advanced metering solution will offer a real open architecture system that will enable customers, and authorized firms such as utilities, ESPs, MDMAs and others to directly access their energy information, on demand, from the meter and also access more timely information through web based presentations. This system would feature a true open architecture.

The pilot is intended to compliment that of other proposed pilots and also fill in gaps in the customer offering. Features include:

- wider end user customer participation, including direct access customers who represent an untapped resource
- focus on reducing T&D system energy constraints, T&D constraints may not coincide with critical peak generation

- focus on developing sufficient information for a full scale (phase 2) effort that will feature CPUC – PSWG compliant open architecture meters that could be accessed through multiple technologies such as a radio and telephone

- not focus on any particular technology as a solution, but be customer specific. Solutions can range from a simple web based information and feedback system to advanced automated facility load controls

By directly accessing energy information, billing quality data and timely energy information will be available at the customer's, ESP's and MDMA's convenience. This approach would also encourage competition to provide energy related information and additional demand response systems to customers. As a result customers and the electrical system would benefit.

An advanced metering system combined with advanced demand response controls will provide the needed customer flexibility, information systems and facility controls to enable customers and their energy services firms to better respond during periods of high peak demand. The benefits of this will help constrained T&D systems and enable energy suppliers to provide additional energy supplies and help reduce peak energy costs.

Metering services would be competitively provided by certified MDMAs. Metering systems for a full-scale program would be those prescribed under the CPUC's PSWG report. To provide maximum customer flexibility and not lock a customer to any particular energy supplier, meters selected will be those that can be adapted to either a telephone or radio based communication system.

Benefits to the California electric system would be reduced demand on certain constrained T&D systems thereby reducing the need for costly upgrades, reducing rolling blackouts. Other benefits include those associated with demand response and load management. Another potential significant benefit would be that with reduced congestion and reduced constraints on a local T&D system, there may be less of a need to employ costly and polluting local peaking units since power outside the local area will be able to be imported into the area.

3.3.2 Population Targets

The target market will include both direct access customers and utility customers. Customers will be from those geographic areas where there are critical T&D constraints. Further information on these locations will need to be provided by the utilities. DA and utility customer participation in the proposed T&D peak constraint programs would be voluntary with an opt in/out provision. For utility bundled customers, we would propose that the local utility have the right of first refusal to provide the proposed services to its bundled customers.

A diversity of types of customers, climate zones and T&D congestion points will be needed for the initial proof of concept test. Customers will include those above and below 200 kW. We anticipate that 5,000 - 10,000 customers, throughout California to be included in the pilot. Participation would be voluntary. DA customers would choose their metering system and control solution/enabling technology. A primary objective of the pilot is to gather the information necessary to determine whether the demand response programs and dynamic pricing options central to the OIR can be economically justified.

DA customers would be recruited by marketing efforts through ESPs and notices sent by their serving MDMA. Non DA customers would be recruited through efforts that the UDCs will use to recruit customers for their critical peak pricing programs. This approach of using the UDCs would be similar to past efforts by the UDCs for their energy efficiency programs directed to bundled and DA customers.

3.3.3 How results Will Be Used in Phase 2 and Beyond

Results from the proof of concept test will be used to establish cost/benefits for a phase 2 effort including: expected T&D constrained demand reduction, program costs, customer preferences and interests in participation, value of providing only information to a customer versus investing in additional facility controls. During phase 2 ,meters that were recently certified as CPUC-PSWG could be introduced.

3.3.4 Determination of the Customer's Load Reduction

(Note – A portion of this section is taken from the UDC Joint Utility - Demand Bidding Program Proposal Dated October 31, 2002 and submitted to Working Group 2)

In order to determine how much T&D the customer actually reduces, the MDMA, Utilities, or ESP must know what the usage would have been before the customer reduces. This Customer Specific Energy Baseline (CSEB) is the 10-day rolling average energy usage determined on a hourly basis, using the average of energy usage for the same hour for the past 10 similar days (excluding days the customer was paid to reduce power under the demand response program or the customer was subject to a rotating outage) prior to a event. The customer's CSEB is compared to the actual amount of kW used for that hour during the DBP Event to determine if the customer complied with the program and if the customer is eligible for the bill credit.

For a longer term, demand load shift, such as creating a new work shift to reduce load or scheduling work for non-critical T&D periods, the customer would present a proposal and if approved the customer would receive the lower T&D charge for the period of constrained demand. This approach is similar to what was done through past utility customized energy efficiency rebate programs. The customer must have interval metering capable of recording usage in 15-minute intervals and Internet access.

3.3.5 Eligibility

Electric Customers who are in T&D constrained areas. This applies to customers above and below 200 kW, there is no size limit for the program. Customers, in addition to direct access customers, would be eligible to participate. Aggregation would be acceptable.

3.3.6 Source of Drivers/Triggers

Drivers and triggers include minimizing the adverse impact of constrained T&D systems, including costs associated with upgrading these systems and the adverse environmental impacts of having to run peaking units in transmission constrained areas.

3.3.7 Intended Level of Participation

The T&D CONTROL program compliments other proposed programs and tariffs. End users can participate in other programs and tariffs, however, double counting of benefits is not allowed.

3.3.8 Sources/Levels of Costs include:

Program development, including administration, marketing, market research, information system development

Program operation, including advanced meters, web information systems, customer specific load control systems. Some customers may already have suitable advanced meters and so they may not need new meters, other customers may already have sufficient demand response technologies installed and so they may only require advanced meters, communication systems and web access.

3.3.9 Method of Cost Recovery

Long run program costs will approach revenue neutrality since the emphasis of the program is to cost effectively reduce congested T&D costs. Cost recovery would be through reduced T&D costs. Additional funding sources would be similar to that proposed by other programs from Working Groups 2 and 3. With CPUC approval of the program concept, founding sources would need to be finalized before program development costs are incurred.

3.3.10 Costs of Pilot vs Expected Dollar or Other Benefits

The cost of the pilot will be controlled by the to be determined cost benefit ratio of program cost to expected benefits. T&D benefits will need to be developed by the local utility. The amount of money to be invested for a customer will be based on the expected T&D benefit and the required cost benefit ratio. For instance, if the required T&D benefit ratio is $600/kW and the customer has a potential to reduce T&D demand by 100 kW, then the limit for costs or incentives to the customer would be $60,000 under the phase 2 system If the customer already has a suitable advanced metering system, then efforts will be made to use that system; thus a potential for cost savings in the program. Although we have not engineered a typical system, but based on the results of the CEC +200 kW meter program, an advanced meter with a web based customer information system could cost $1,000 to $3,000 for a C&I customer with operating costs additional.

Implementation costs involve the following categories:

- Project management
- Customer education
- Meter hardware and installation
- Load control systems/enabling technology
- Meter reading and communication
- Data retrieval, validation and management
- Information treatment
- T&D reduction incentives

3.3.11 Estimated Start Date

For a “quick win” approach, with CPUC approval in February, 2003, marketing would begin in March 2003 and proof of concept operation would begin in June 2003. Based on results of the proof of concept the program would be expanded for maximum coverage in the summer of 2004.

The CPUC should note that this effort requires initial engineering and development expenses to develop the program and its needed systems. These investments are not likely to occur until after the CPUC has approved the basic program design and parameters.

3.3.12 Method of Implementation

Key points are:

- Implementation of the program for direct access customers would be by certified MDMAs, with the cooperation of the ESP, Scheduling Coordinator and local utility.
- Utilities would identify constrained T&D areas and would identify cost effective incentives for reducing T&D constraints. These incentives would be subject to CPUC approval.
- MDMAs and ESPs would market the program to direct access customers. Only those direct access customers whose contracts with their ESP permit such participation would be eligible.
- MDMAs would be responsible for calculating customer T&D reductions.
- We suggest a party such as the CPUC or a independent firm be contracted to administer this program.

Implementation plan:

- receive CPUC approval of concept and funding sources
- develop additional program analysis and details, including T&D cost savings/benefits, target market size and characteristics
- develop program rules and procedures
- develop necessary back office systems for phase 1
- begin marketing
- begin actual installations
- evaluate results
- based on positive results, proceed to wide scale program deployment.

3.3.13 Other Implementation Issues

Since the utilities are the source of information on locations and extent of T&D constraints and potential costs and benefits, we have not attempted to estimate these. However this information is critical before proceeding with detail program design and implementation.

For this T&D effort to be successful, the support and cooperation of utilities and direct access firms is essential.

SECTION 4 - DISCUSSION OF THE RESULTS OF PG&E'S PRELIMINARY BUSINESS CASE ANALYSIS

The statewide pricing pilot (SPP) is in part designed to reduce key uncertainties that have been identified in a preliminary business case analysis performed by Pacific Gas and Electric Company (PG&E) and Charles River Associates (CRA). On October 31, 2002, PG&E and CRA shared the results of their cost-benefit analysis at a WG3 meeting, because they believed that the information would be useful in providing a context for demonstrating the need for performing a statewide pricing pilot as described in Section 3.0.

PG&E and CRA emphasized that the analysis presented should not be construed in any way to be definitive conclusions about the utility deployment costs and operational benefits or the absolute societal benefits of implementing dynamic pricing options. PG&E reserves the opportunity to present its final business case analysis in Phase II of this proceeding.

However, two conclusions should be drawn from the information presented in the preliminary analysis:

1. First, in determining the utility cost/benefit "gap" (i.e., the financial gap between the costs to deploy an advanced metering system infrastructure less utility operating benefits reasonably achievable as a direct result of that deployment), each California utility must determine its specific deployment and operating costs and compare them to its unique operating benefits. The gap will vary from utility to utility. These assessments should be performed by each utility and thoroughly examined in Phase II of this proceeding.

2. Second, there are considerable uncertainties in the estimated societal benefits resulting from dynamic pricing. These uncertainties can be reduced through the proposed statewide pricing pilot. Consequently on a parallel path to assessing the utility cost/benefit gap in Phase II, the utilities should conduct the proposed rigorous and well-designed dynamic tariff pilot to establish a more robust estimate of the societal benefits of dynamic pricing.

The results of the statewide pricing pilot, along with the findings of the utility cost/benefit gap analyses, can be combined to perform an overall cost-effectiveness analysis with results expected as early as late Fall 2003.

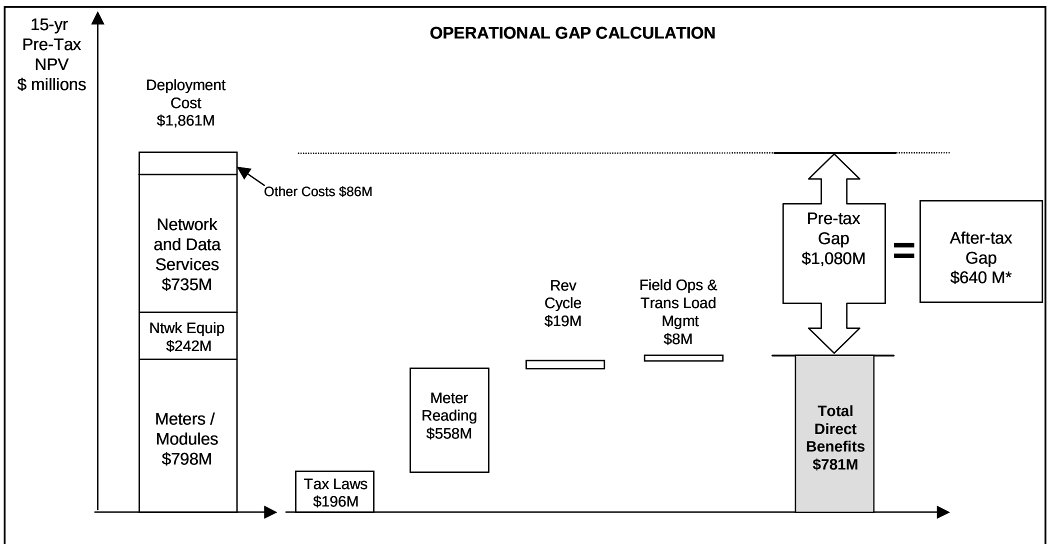
The findings of PG&E's/CRA's preliminary business case analysis and how they link to the proposed statewide pricing pilot are addressed below.

4.1 Preliminary Utility Cost/Benefit Analysis Performed by PG&E Indicates An Operational Financial "Gap" of About $1 billion Pre-Tax (or $640 million After-Tax)

Over a 15-year study period, PG&E estimates that for its service territory, the net-present-value (NPV) of costs to universally deploy an advanced metering system infrastructure and meters for its customers below 200 kW is approximately $1.8 billion (pre-tax). The corresponding operational benefits without consideration of the demand response benefits are approximately $0.8 billion. Hence, the company faces an operational financial "gap" of about $1 billion pre-tax (or $640 million after-tax) (See Chart 4.1). On an annualized basis, the gap equates to a pre-tax revenue requirement of about $120 million per year, when operational benefits are realized as an offset to the deployment costs. On a per-electric-meter basis, the gap equates to approximately $2 per month per meter over a 15-year period. PG&E also examined some sensitivities around the $1 billion gap figure, indicating it could range between $959 million and $1,351 million depending on whether or not pending energy-related tax legislation passes, cost contingency assumptions and advanced metering system equipment useful life assumptions.

However, the relative magnitude of the gap illustrates why it is important to truly understand the societal benefits resulting from dynamic pricing and why a robust pilot is necessary for 2003 to acquire that understanding.

Figure 4-1. Operational Gap Calculation



*Internal sensitivity analysis indicates a range of $562 to $808 M of after-tax operational gap ($948 to $1,364 M pre-tax).

4.2 Key Assumptions in Assessing PG&E's Utility-Side Costs and Benefits

4.2.1 "Universal" 5-Year Rollout; All Electric and Gas Meters

PG&E's analysis assumed a "universal" deployment of advanced metering technology to all electric customers below 200 kW and all gas meters in portions of PG&E's service territory where there is combined electric and gas service. PG&E has asked the CPUC in this proceeding to consider including gas meters in a deployment since as a combined electric and gas utility, meter reading operational benefits are substantially reduced if only one commodity meter is automated and not the other.

The 5-year rollout is assumed to begin in April 2004, assuming the CPUC has concluded in late 2003 that the IOUs should rollout an advanced metering system universally. For PG&E, a universal rollout would involve automating about 4.7 million electric meters and 3.3 million gas meters, for a total of 8 million meters. That represents approximately 90% of the total meter population for customers below 200 kW. The balance of meters resides in the heavily rural areas of PG&E's service territory in which the cost of deploying an advanced metering system technology rises uneconomically vis-à-vis the incremental benefit. The 90% penetration is consistent with what has been achieved at other utilities that have deployed an advanced metering system technology.

4.2.2 Daily Time of Use (TOU) and Critical Peak Pricing (CPP) Electric; Monthly Gas

PG&E assumed that the metering technology deployed for the preliminary business case would provide a minimum of daily TOU capabilities for electric customers consistent with tariff designs that were being considered by WG3. In addition to this universal TOU capability, the technology also provides the capability for dispatching one of a small number of pre-identified fixed-CPP price signals on a day-ahead basis. Monthly reads would also be provided for gas meters. Functional requirements can significantly impact the cost of deployment (e.g., if in contrast to TOU/CPP, one wanted to bill residential customers based on hourly price signals). PG&E assumed that TOU/ fixed-CPP functionality was the appropriate assumption for purposes of the preliminary business case analysis.

4.2.3 Representative Proven Technologies; Indicative Costs

PG&E incorporated the costing of radio frequency (RF) technology in the business case analysis. This is a proven technology and the majority of current U.S. utility automatic meter reading (AMR) installations have utilized that technology (75-85%). In addition, PG&E examined other technologies (e.g., powerline carrier (PLC)) and concluded that most commercially available AMR or advanced metering system technologies would provide similar functional capabilities as RF within the same relative cost-per-meter range.

PG&E emphasized that it is not wedded to any particular technology and indicated that a deployment of this magnitude would likely incorporate various complimentary technologies to accommodate the diversity of PG&E's service territory and would conduct an RFP process before making any final technology selections.

In addition, to help PG&E better understand what is involved in an actual deployment, PG&E visited two utilities that have deployed this technology, Ameren UE in Missouri and Puget Sound Energy (PSE) in the state of Washington. Ameren deployed about 1.5 million electric and 0.3 million gas meters between 1994-2000. PSE recently completed their deployment to 0.9 million electric and 0.6 million gas customers. Unlike Ameren's system that was deployed primarily to replace manual reading, much of PSE's system is daily TOU capable.

Key findings from those visits included the following:

Deployment of an Advanced Metering System - Scalable, consisting primarily of regionally located metering and networking material warehousing/distribution centers, supplying field installers on a daily basis. Bulk deployment is achievable, even for a utility the size of PG&E, in a 4-5 year period.

Benefits – Found essentially the same benefit categories assessed. However, benefit magnitudes can vary across utilities depending on specifics of customer base, geographic and climatic conditions, maturity of operation processes and techniques.

Costs – Based on the Ameren UE and PSE visits, PG&E concluded that to reasonably assess deployment costs, it needed to assess meter and network costs based on its actual detailed meter inventory and geographic dispersion of its customer/meter base.

4.3 Advanced Metering System Deployment Cost Estimates

PG&E examined four key areas of the costs of deployment. These costs were estimated based on examining market prices for materials and labor, vendor-supplied estimates, applying such costs across PG&E's detailed meter inventory and geographic dispersion of its customer/meter base, and comparing such costs against other utilities in deployment. To help validate the estimated deployment costs, PG&E engaged the consultant who also prepared PSE's utility cost/benefit analysis. Over a 15-year study period, PG&E estimates that for its service territory, the net-present-value (NPV) to universally deploy an advanced metering system infrastructure and meters for its customers below 200 kW is approximately $1.8 billion pre-tax ($1.1 billion after-tax). This converts on average to approximately $100 capital per metered point. The four key cost areas are summarized below:

4.3.1 Advanced Metering System Meter Modules

These costs are those associated with purchasing and installing the AMR meters and modules over the study period. By each meter class, PG&E selected the lowest costs between a new integrated advanced meter systems meter and a reconditioned existing meter with an advanced meter systems capable module. Over the 15-year study period, these costs were estimated at $798 million on a pre-tax NPV basis.

4.3.2 Network Capital

These are the costs associated with building a dedicated network to support a universal deployment of an advanced metering system based on an RF technology reaching 90% of electric and gas meters in PG&E’s combined electric/gas service area. As an alternative to building a dedicated network, some available technologies can utilize a public network. However, the costs would remain whether the utility owned a dedicated network or leased space on a public network. Over the 15-year study period, these costs totaled $242 million on a pre-tax NPV basis.

4.3.3 Network and Data Services

These costs encompass the ongoing maintenance of the network as well as data processing associated with aggregating daily TOU/CPP reads for electric, and monthly reads for gas, and conveying the data to the utilities existing billing systems. Over the 15-year study period, these costs totaled $735 million on a pre-tax NPV basis.

4.3.4 Other Costs

Additional costs were assessed for project management, back-office systems integration, network power and pole attachment, and ongoing meter maintenance costs including battery replacements. Over the 15-year study period, these “other” costs totaled $86 million on a pre-tax NPV basis. Not included in the preliminary business case analysis were any costs for customer-side enabling technologies (e.g., smart thermostats).

4.4 Universal Advanced Meter System Deployment Timing Considerations

Chart 4.2 summarizes the deployment timing of meter installations over a 5-year rollout assumed to begin in April 2004 for illustration purposes. PG&E emphasized that realistic implementation timeframes for full-scale deployment must be carefully considered and factored into the cost/benefit analysis in Phase II of this proceeding. A full-scale deployment for utilities the size of the California IOUs would be of the largest magnitude ever undertaken in the U.S. to date.

Fortunately, deploying advanced metering systems is scalable, and historically has been rolled out primarily through regionally located metering and networking material warehousing and distribution centers, supplying field installers on a daily basis.

Table 4-1. Meter Installations Over a 5-year Rollout

(thousands)	**2004**	**2005**	**2006**	**2007**	**2008**	**5yr Totals**
Existing Meters Converted/Year	263	1,964	2,882	2,047	369	7,525
Annual System Load Growth	76	102	98	100	99	475
Total Meters Automated	339	2,066	2,980	2,147	468	8,000

While bulk deployment is achievable in 4-5 year period, even for utilities the size of the California IOUs, there are four key deployment phases that the utilities should address in their cost/benefit analyses in Phase II. These phases are based on the experience of utilities across the U.S. that have undergone full-scale deployment of advanced metering technologies. These phases are reflected in PG&E's preliminary business case rollout schedule shown in Table 4.2.

1. Project Planning, Integration Network Engineering – First, it can take 3-6 months from contract approval to identify/prepare metering and customer databases, engineer the network, address deployment logistics, and stage feeder stock before the first meter gets installed.

2. Evaluation Phase – Once first meter installs begin, initial installations would be used to test and refine deployment processes, train personnel, and correct unforeseen issues. This evaluation phase would extend an additional 3-4 months beyond the project planning, integration and networking engineering phase. IOUs would establish milestone agreements with third parties to ramp up to full rollout following this phase.

3. Production Phase – Once processes are tested and tuned, ramp up to full production occurs and continues through years 2-4 of deployment. By the end of the production phase, 90-95% of the meters targeted for replacement or retrofit will have been completed. During this phase, approximately 240,000 meters per month (or 11,000 meters per day) would be installed in PG&E's service territory.

4. Clean Up Phase – As urban and suburban areas are completed in the production phase, rural areas and urban/suburban meters requiring special handling would be handled in the clean up phase. 5-10% of the meters targeted would be completed in this final phase.

4.5 Utility Operational Benefits

PG&E examined four major areas of operational benefits a utility would expect to realize benefits from implementation of an advanced metering system: 1) meter reading, 2) revenue cycle, 3) field operations, 4) transformer load management and system planning. In addition, the areas of revenue protection and meter operations were evaluated and are discussed in section 4.6.2. These benefits can vary across utilities depending on the maturity of existing business processes and the extent to which process and technology improvements (other than advanced metering system related) have already been deployed to capture operational efficiencies.

1. Meter Reading. This benefit area reflects the cost reductions in the area of meter reading, both in route reads and pick-up reads (e.g. move-in/move-out reads). This benefit was determined based on how much the present workforce and associated costs can be reduced, considering the coverage of the new technology, assuming not all meters can be economically read using the new technology and some will still be manually read. Over the 15-year study period, these benefits totaled $558 million on a pre-tax NPV basis.

2. Revenue Cycle. This area reflects the cost reductions anticipated due to fewer customer calls to the utility to express concerns over meter reading and billing issues, such as high bills, delayed bills, and estimated bills. It also reflects the amount of cost reductions as a result of not having to issue as many rebills due to improper estimation and other factors and potential cash flow improvements due to fewer delayed bills. Each utility will need to base any anticipated savings on the number of high bills, estimated bills, costs for issuing re-bills, and estimates on the impacts to these cost items. Over the 15-year study period, these benefits totaled $19 million for PG&E on a pre-tax NPV basis.

3. Field Operations. This benefit area covers the amount of estimated reductions in unnecessary field dispatches for customer reported outages that were on the customer side of the meter by virtue of having a meter system that can report whether there is power available at the meter location. Actual savings for each utility would have to be based on the present number of times this type of dispatch operation actually takes place as opposed to the number of customer outage calls received. Over the 15-year study period, these benefits totaled $1 million for PG&E on a pre-tax NPV basis.

4. Transformer Load Management and System Planning. This benefit area is targeted at the cost savings that would occur as a result of better system planning data. Types of cost savings believed to fit in this category would include fewer oversized (more expensive) transformer installations for both new business and system load growth as well. Over the 15-year study period, these benefits totaled $7 million for PG&E on a pre-tax NPV basis.

4.6 Additional Benefits Categories Considered

In addition to the operational benefits described in Section 4.4, PG&E also examined the following areas for potential benefits to consider in a universal advanced metering system deployment.

4.6.1 Pending Energy-Related Tax Legislation

PG&E considered the potential financial impact of pending tax legislation in its preliminary utility cost-benefit analysis. Specifically, House of Representative Bill 4 (HR4) and Senate Bill 517 (S517) would allow special tax treatments for qualified energy management devices. However, such legislation has not been signed into law to date, but is anticipated to be passed in 2003. Over the 15-year study period, assuming such legislation was signed into law, PG&E estimated such benefits at $196 million on an NPV basis.

4.6.2 Unaccounted for Energy (UFE)

Two additional categories considered in some utility business cases are improved metering accuracy and reduced meter tampering and energy theft. A fully deployed advanced metering system would reduce such unaccounted for energy (UFE). This reduction represents the transfer of money from one group of ratepayers to another group. For instance, if a greater percentage of meters are running accurately, then a greater percentage of customers are paying their fair share of the authorized revenue requirement. Accordingly, while this results in more accurate billing of customers, such benefits would not reduce overall revenue requirements to help offset the costs of deploying an advanced metering system.

4.6.3 Transmission, Distribution and Generation Benefits

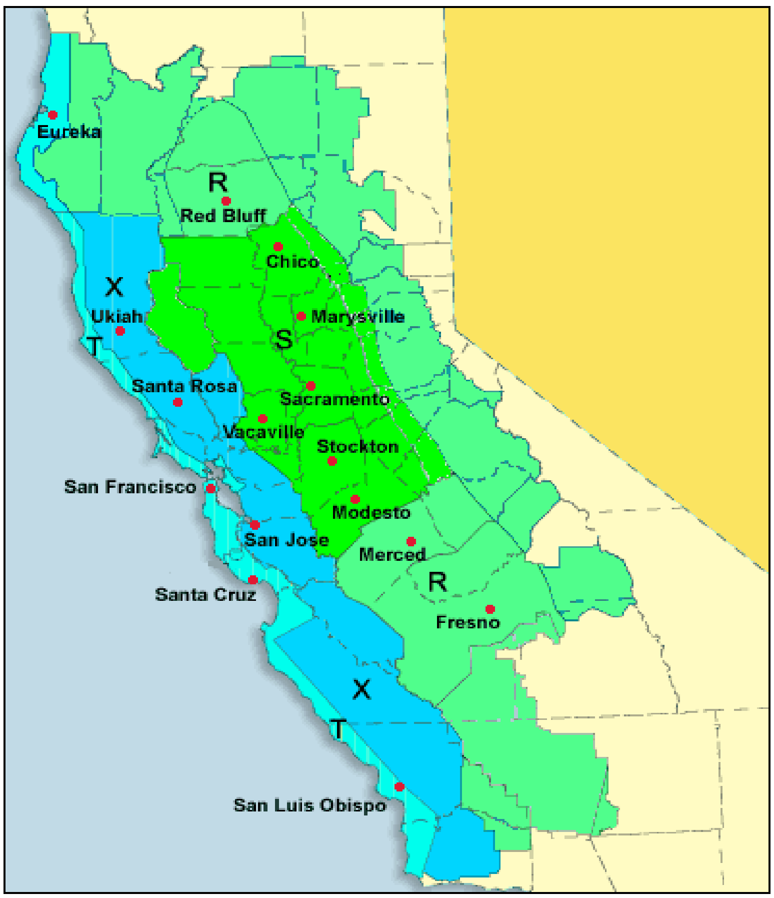
PG&E addressed benefits associated with transmission, distribution and generation costs in the discussion of resource and societal benefits presented by CRA since such benefits would be directly a function of the degree of customer response to dynamic pricing options. These are addressed in the next section.

4.7 Framework for Assessing Benefits of Dynamic Pricing for PG&E's Customers Under 200 kW

Charles River Associates (CRA) was retained by PG&E to estimate the benefits of dynamic pricing options for customers with demands less than 200 kW. After a review of various pricing options, CRA quantified the impact of two dynamic pricing options for PG&E: a two-period time-of-use (TOU) pricing rate and a CPP-F rate, which features a pre-specified high price that can be dispatched on short notice during critical times for up to 15 times a year, and a standard TOU price during all other times.

CRA utilized the standard practice methodology to estimate benefits of load shifting across multiple perspectives, including the total resource cost (TRC), ratepayer impact measure (RIM), and participating customer tests (PT)[34]. For the residential analysis, CRA defined four climate zones, based on PG&E's existing baseline territories, and conducted the analysis at the zonal level. The geographical boundaries of the four zones are shown in Chart 4.3. The analysis was conducted for three different rate classes: Residential (E-1), Small Commercial (A-1, <20kW), and Medium Commercial (A-10, >20kW and <200kW). PG&E's billing and load shape data was used to estimate the flat prices that correspond to the existing five-tiered inverted rate structure.

Figure 4-2. PG&E Climate Zones



[34] California Public Utilities Commission, "California Standard Practice Manual: Economic Analysis Of Demand-Side Programs and Projects," October 2001, San Francisco, California.

4.8 Key Assumptions in Assessing Dynamic Pricing Benefits

Recognizing that all energy forecasts are fraught with uncertainty, CRA developed projections for a lower-end case and a higher-end case. Through sensitivity analysis, CRA identified the following three factors as being the most significant determinants of program benefits: price elasticities of demand, avoided cost of capacity, and customer opt-out rate.

Assumptions for measuring customer response in the form of price elasticities of demand were derived through a comprehensive literature review covering the past quarter century of experiments and field trials with TOU pricing and CPP pricing. For Central Valley residences, the lower-end own-price elasticity of peak usage was –0.1, while the higher-end elasticity was –0.3. This range was lower in the milder climate zones, and ranged from –0.05 to –0.15. For the small commercial analysis, we used values that were one fourth as large as those for residential customers in the Central Valley.

The analysis used CEC and Lawrence Berkeley Lab (LBL) projections of avoided costs. The marginal cost of capacity had a base year value of $43/kW-year[35] in year one at the lower-end of the range and rose to $100/kW-year[36] at the higher-end (CEC). These values escalated at 4.0% a year over the 15-year time horizon.

The meter deployment strategy assumed 90% customer coverage. The analysis assumed an opt-out participation format with lower-end opt out rates of 20% for the TOU and 40% for the CPP. The higher-end rates were 10% for the TOU and 20% for the CPP.

Program benefits were estimated over a 15-year time horizon, using a discount rate of 7.7%. Other assumptions that did not vary across the cases included: line losses of 9.1%, generation reserve margin of 15%, and marginal energy costs during the base year of 4.22¢ during the peak period and 3.05¢ during the off-peak period.

4.9 Dynamic Pricing Benefits – Preliminary Results

Figure 4-3 contains total resource costs (TRC) gross benefits, excluding T&D benefits or lost revenues, for the lower-end and higher-end assumption sets. Commodity benefits vary greatly due to uncertainty in key assumptions. In particular, the NPV benefits of CPP pricing for all customer classes range from $418 to $2,306 million, and those of TOU pricing range from $115 to $680 million.

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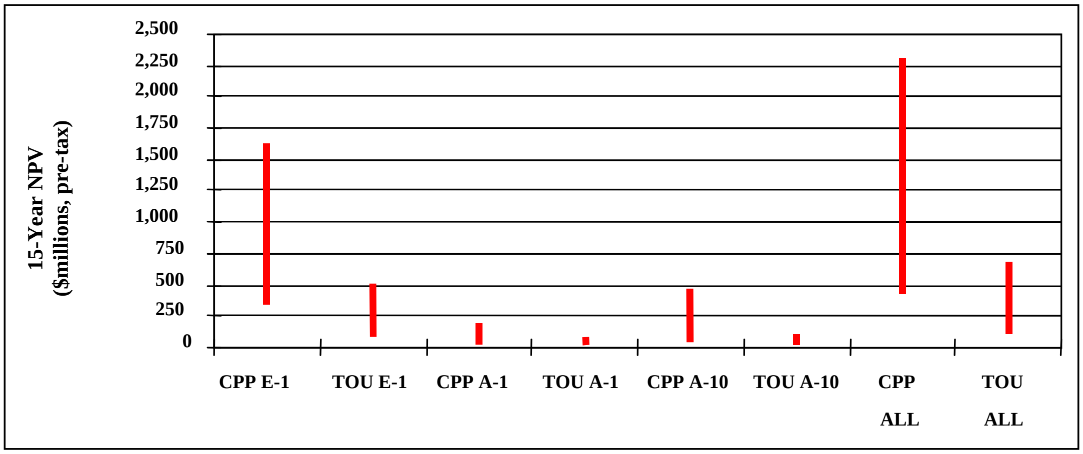
35 LBL numbers: Robert Van Buskirk, "Dynamic Pricing Cost/Benefit Analysis for Pilot Design," Energy Analysis Department, LBNL, no date.

36 CEC numbers: "2002-2012 Electricity Outlook Report", California Energy Commission, Feb. 2002

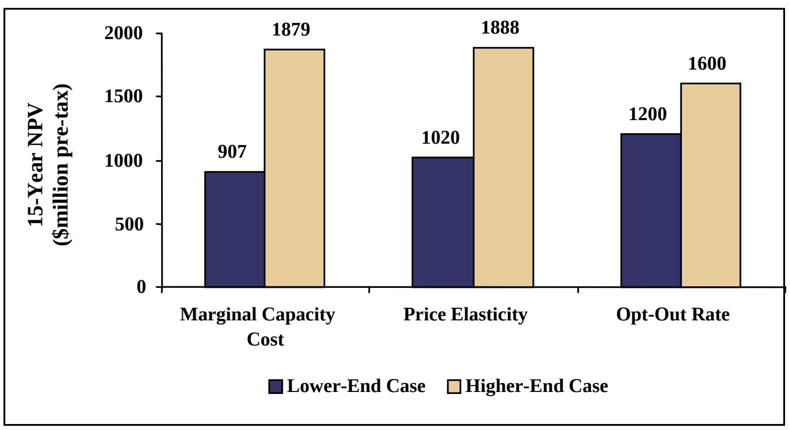
*Figure 4-3. Total Resource Costs (TRC) Gross Benefits**



* Does not include T&D benefits or lost revenues.

Figure 4-4 shows the variation that occurs in commodity benefits when individual sensitivity analyses are performed on key assumptions pertaining to MCC, elasticities, and opt-out rates.

*Figure 4-4. Total Resource Cost (TRC) Gross Benefits**



* Does not include T&D benefits or lost revenues.

4.10 Factors in Decision Making

Figures 4-3 and 4-4 show commodity benefits of load shifting from a TRC perspective. In addition, there will be transmission and distribution (T&D) benefits from a TRC perspective. These combined T&D benefits would guide state policymaking. Also, PG&E may experience lost revenue with the new rate designs, and will need to evaluate benefits from the RIM perspective. Table 4-2 shows the impact of the additional T&D benefits and lost revenue on the RIM.

Table 4-2. Combined Benefits of CPP/TOU Pricing

	TRC Benefits	T&D* Benefits	Total TRC Benefits	Lost Revenue	RIM
	(A)	(B)	(A+B)	(C)	(A+B)-(C)
Lower End Case	$418	$143	$561	$316	$245
Higher End Case	$2,298	$339	$2,637	$923	$1,714

T&D benefits are only attainable to the extent load shift occurs and persists if customers respond to dynamic rates.

4.11 Conclusions from CRA Analysis

Several conclusions can be drawn from the CRA analysis as summarized in Chart 4.6. First, the CPP options have much higher benefits, clearly dominating the TOU options. Second, absent the proposed statewide pilot program, there is considerable uncertainty in the estimated benefits of dynamic pricing programs. The TRC benefits of the CPP option vary by almost a factor of five from the lower-end case to the higher-end range. The value of MW savings obtained in the final year of the Low End Case TRC Benefit was determined to be 951 MW and in the final year of the High End Case TRC Benefit the savings were determined to be 2,530 MW. The percent MW impacts were calculated to be -9.6% and -25.6% for the Low End and High End Cases, respectively. In addition, the estimates of lost revenue are also characterized by wide variability. Consistent with standard regulatory practice, these lost revenues would have to be recovered by PG&E.

4.11.1 Sensitivity Analysis Using CPUC Marginal Cost Estimates

After this analysis was completed, the ALJ provided two sets of marginal costs for consideration by WG3. These numbers came from the CPUC. CRA used one of these sets to perform a sensitivity analysis. The CPUC only provided information on avoided costs during the peak period. In order to perform our analysis, CRA used the CEC derived costs for the time periods where there are no CPUC values. In addition, the CPUC only provided one year's worth of data. CRA escalated the data using the growth rates implicit in the CEC projection over the 15-year time horizon. In addition, some variable O&M was added to the avoided energy costs. CRA ran a sensitivity using this new stream of marginal costs and compared it to estimates that were obtained using the CEC marginal costs. The TRC benefits of the CPP option with the CEC marginal costs have a 15-year NPV of $1,600 million. This value dropped by 5.8% to $1,507 using the CPUC marginal cost set. None of the conclusions reported in the previous are affected.

4.12 Key Determinants of Cost Effectiveness Analysis for Advanced Metering

Key uncertainties and cost drivers uncovered in the preliminary business case analysis performed by PG&E and CRA are as follows.

4.12.1 Structure of the Tariff – Difference Between Peak and Off Peak Prices

The TOU and CPP tariffs considered in this analysis are designed to be revenue neutral with the existing tariffs. The average residential customer pays an average of 13.5 cents per kWh during the summer months and 13.34 cents per kWh during the winter months. If the average customer was to be moved to either the TOU or CPP tariffs, and they did not change their load shape, they would experience no change in its electric bill.

The residential TOU tariff has a two-period structure, with the peak period lasting from noon to 6 pm during weekdays on days other than holidays; all other hours are offpeak. During summer, the peak price is 18.05 cents per kWh and the offpeak price is 12.43 cents per kWh. During the winter, the peak price is 15.83 cents per kWh and the offpeak price is 12.86 cents per kWh.

The CPP features a high price that may be applied during the summer months to the peak period hours for up to fifteen days, representing about 1% of the hours in the year. The residential CPP tariff has a critical peak price of 48.07 cents per kWh, a regular peak price of 15.94 cents per kWh and an off peak price of 11.44 cents per kWh. The winter prices are the same as the simple TOU rate.

4.12.2 Customer Opt Out Rates for Dynamic Tariffs (Dependent on Interest, Information and Technology)

The lower end estimates of benefits are associated with higher end values of opt-out rates and vice versa. The analysis assumed an opt-out participation format with lower-end opt out rates of 20% for the TOU and 40% for the CPP. The higher-end rates were 10% for the TOU and 20% for the CPP. These rates are estimates based on limited prior studies. Since op-out rates have a significant effect on total benefits, the data to be collected via the proposed statewide pricing pilot will be very valuable in making more precise benefits estimates.

4.12.3 Price Elasticities – Particularly Unknown for Small Customers

Assumptions for measuring customer response in the form of price elasticities of demand were derived through a comprehensive literature review covering the past quarter century of experiments and field trials with TOU pricing and CPP pricing. For Central Valley residences, the lower-end own-price elasticity of peak usage was –0.1, while the higher-end elasticity was –0.3. This range was lower in the milder climate zones, and ranged from –0.05 to –0.15. For the small commercial analysis, we used values that were one fourth as large as those for residential customers in the Central Valley.

4.12.4 Value of Peak Savings

The value of peak savings associated with CPP pricing ranged from $ 561 million to $ 2,637 million. This included the commodity benefits and also the T&D benefits caused by load shifting.

4.12.5 Deployment Costs of an Advanced Metering System Infrastructure

In order to complete a thorough cost/benefit analysis, in Phase II of this proceeding the utilities will need to determine and provide their individual utility specific costs associated with deploying an advanced metering system infrastructure for each service territory. This more detailed cost determination should be built upon a firm record and will likely need to be based on the costs provided by identified qualified vendors who are responding to confidential utility initiated Requests for Proposals (RFP’s). Each cost proposal must be put together considering the characteristics of the proposed technologies in association with each utilities geography, demographics, installed meter population and the functional requirements established by the utilities and these proceedings.

4.12.6 Operating Benefits and Costs of an Advanced Metering System Infrastructure

In order to complete a thorough cost/benefit analysis, each of the utilities as part of the Phase II of the proceeding will need to determine and provide the operational benefits they expect to result from the deployment of an advanced metering infrastructure. These utility-specific benefits should be calculated in accordance to both the capabilities of the potential advanced metering system and the related impact that system will have on each utility's present operational processes and costs.

The PG&E/CRA analysis did not consider or quantify a wide range of possible costs associated with an advanced metering system. For example, the technology associated with an installed advanced metering system infrastructure could increase the number of service calls and the need for field response to malfunctioning meters or infrastructure. Similarly, billing problems could increase due to malfunctioning technology. In addition, a reduced workforce would affect a utility's detection of hazards and ability to respond to emergencies. These costs must be considered in a full cost/benefit analysis of advanced metering systems.

4.13 Statewide Pricing Pilot Designed to Reduce Two Key Uncertainties: Customer Opt Out Rates, Price Elasticities

The statewide pricing pilot (SPP) is in part designed to reduce key uncertainties that have been identified in the preliminary business case analysis performed by Pacific Gas and Electric Company (PG&E) and Charles River Associates (CRA). Specifically, the SPP will assess customer opt out rates and elasticities to a range of pricing options.

4.14 Value of Peak Savings Can Be Addressed in Procurement Process and Planning Proceedings

The valued of peak savings is also largely driven the by the assumed marginal costs of generation capacity. The statewide pricing pilot will not address this variable. Instead, WG3 will look for direction from Working Group 1 regarding the marginal costs to assume for purposes of the cost effectiveness analysis to be performed in Phase II following the completion of the SPP and individual utility business case analyses.

4.15 Costs of Statewide Pilot Justified Since Pilot Will Narrow Range of Uncertainties Considerably

Comparing the range in the value of peak savings associated with CPP and the financial gap identified in PG&E's utility cost/benefit analysis, the net benefits of implementing CPP on a full-scale basis range from a loss of about $500 million to a gain of $1.5 billion. The purpose of the statewide pricing pilot (SPP) is to reduce this range of uncertainty. If the choices are simply to engage in a full-scale rollout of CPP or stick with the existing tariff structure, and if the probability distribution of net benefits can be simplified as a 50/50 chance of either losing $500 million or gaining $1.5 billion, then the value of information provided by SPP is $250 million, because the state would lose $500 million with a 50% probability. The cost of the pilot is likely to be a fraction of that amount. Thus, it is prudent business strategy to proceed with the pilot.

4.16 Policy Question – Should Costs and Benefits of Universal Advanced Metering Systems Be Considered/Analyzed for All Customers or Only Those Below 200 kW?

The business case cost and benefit analysis presented above represents one method of determining whether the costs of deploying advanced metering are justified. It is focused necessarily on the costs of metering infrastructure for customers below 200 kW and analyzes the range of potential benefits flowing from that investment. It does not contemplate that costs and benefits unrelated to installing metering infrastructure for customers under 200 kW would be included in the analysis. In the WG3 meetings, however, the issue was raised whether an analysis should be done which encompasses costs and benefits of advanced metering systems for all customers, both below and above 200 kW. The issue was not resolved, however, owing to time constraints. WG3 recommends that as part of phase 2, WG1 solicit additional discussion from the participants on this issue so that WG1 can give suitable guidance to the participants as to how the cost benefit analysis in Phase 2 should be conducted.

SECTION 5 - PLAN TO EVALUATE AND LINK RESULTS FROM THE PILOT TO FUTURE COST EFFECTIVENESS ANALYSIS

There are four key pieces of information believed necessary to enable decision-makers to determine the cost-effectiveness of deploying advanced metering systems across California. These are 1) the costs anticipated by each utility to roll-out an advanced metering system, 2) the operating benefits anticipated by each utility resulting from implementation of an advanced metering system, 3) the elasticities of demand and opt-out rates for customers who would be placed on dynamic pricing tariffs, and 4) an estimated marginal cost of generation.

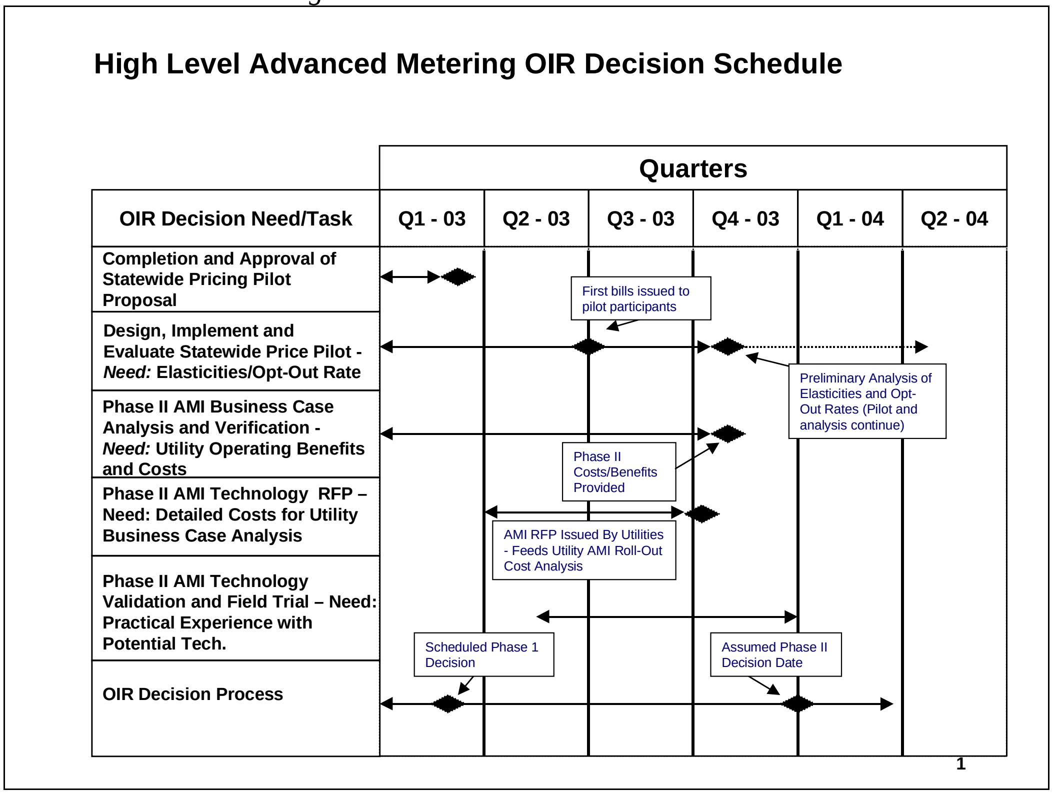
The first two items, the costs and benefits of each utility implementing advanced metering systems are anticipated to be developed and provided as a part of Phase II of this proceeding. Further, it is anticipated that the development of analysis-quality costs will need to be supported by a thorough Request for Proposal (RFP) process with vendors. A first level cost/benefit assessment based solely on utility costs and benefits can be made with this portion of the data. According to the preliminary results from the business case study discussed in Section 4, for PG&E there is a significant gap in costs over benefits.

It is anticipated that other societal and generation benefits are identifiable and should be looked at by decision-makers that could help provide the foundation for authorizing the needed rate recovery for the utilities to offset any such benefit gap or shortfall. One such benefit is the societal and generating cost savings associated with the demand reductions resulting from dynamic rates enabled through an advanced metering system deployment. Currently, the magnitude of these savings cannot be accurately forecasted. Customer participation rates (opt-out rates) as well as projected elasticity of demand in response to dynamic pricing are needed to project these savings.

Elasticities and opt-out rates will be determined through the recommended SPP. This information resulting from the pilot will be used to project and estimate the load reductions/shifts that would result from implementing various dynamic pricing options. Building upon these elasticities of demand and opt-out rates, the estimated marginal cost of generation for this reduced or shifted usage can be used to estimate the associated reduced generation costs.

Once the pilot has produced results, and utilizing the other three pieces of information discussed above, decision makers can determine whether sufficient societal benefits exist to support the authorization of the rates necessary for utilities to pursue full scale advanced meter system deployment. Based upon the recommendations contained in this WG3 report, each of these pieces of information is contemplated to be available as early as mid-4th quarter, 2003, and the overall timing of these interrelated activities is illustrated in **Figure 5-1** below.

Figure 5-1. Advanced Meter Decision Schedule



SECTION 6 - PROPOSED COST RECOVERY MECHANISMS

Prior to a significant commitment of expenditures, the utility distribution companies (UDCs) request explicit Commission authorization to spend such amounts. Specifically, the CPUC must define the amount of expenditures authorized for approved tariffs and programs, experimental statewide pilot program, and preparatory work necessary to timely implement decisions in R.02-06-001 (even if that preparatory work precedes the decisions). The CPUC must further define the explicit cost recovery mechanism and process that will provide UDC funding within a reasonable period of the expenditures incurred by the UDC.

6.1 Methods of Cost Recovery

The UDCs should (1) be allowed to established regulatory accounts to record incremental one-time and on-going program costs not currently covered in rates, (2) utilize established balancing accounts to recover under-collected revenues, and (3) utilize established balancing accounts to recover customer incentive payments.

The UDCs recommend the following cost recovery treatment for all costs of assessing, acquiring, deploying, installing and operating and maintaining advanced meter technologies (including related communications hardware, billing systems, and measurement data collection software enhancements) and all incremental costs of designing, implementing, and marketing programs, tariffs, and pilot studies approved by the CPUC in this proceeding.

6.1.1 O&M and A&G Costs To Implement The Statewide Pilot Program (SPP) And Large Customer Tariff Programs Incurred Prior To The Phase I Decision

Between now and February 2003, when the CPUC is expected to issue its Phase I decision, the UDCs must continue to undertake various activities necessary to optimize the chance that the SPP study (expected to be approved in the Phase I decision) can be implemented by June 2003. Similarly, some advance work needs to occur to start implementing the WG 2 large customer tariff programs. The CPUC must establish a vehicle to allow the costs of these reasonable preparatory activities to be recorded and recovered. To this end, the UDCs recommend that for one-time and on-going incremental operations and maintenance (O&M) and administrative and general (A&G) costs associated with work prior to a Phase I decision, the CPUC authorize each UDC to create a regulatory account to record such costs. ***Such authorization is requested as soon as possible to allow this work to continue.*** The details of the proposed Advanced Metering and Demand Response Account (AMDRA) to accomplish this are described in the following attachment. Prior to the Phase I decision, the AMDRA expenses would be capped at a total $1 million for all three utilities combined. Each year's recorded O&M and A&G cost will be recovered in the subsequent year via an annual advice letter filing, which adds these costs to the UDCs' annual revenue requirements. The advice letter filings would use adopted cost allocation and rate design[37].

6.1.2 O&M and A&G Cost Incurred Subsequent to the Phase I Decision

Subsequent to the Phase I decision, one-time and on-going incremental O&M and A&G costs authorized by the CPUC should be estimated and planned for the next five years. The UDCs propose that the Phase I decision order a modification to the AMDRA to remove or increase the $1 million cap and to allow the UDCs to record additional one-time and on-going incremental capital, O&M, and A&G costs for approved tariffs and programs, the SPP, and any preparatory work reasonably necessary to ensure timely implementation of further decisions in R.02-06-001.[38] The UDCs will record costs annually in the AMDRA. Each year's regulatory account cost will be recovered in the subsequent year via an annual advice letter filing, which adds these costs to the UDCs' annual revenue requirements. The advice letter filings will use adopted cost allocation and rate design.

6.1.3 Capital

All capital additions incurred for these programs should be treated as authorized additions to the respective UDC's plant and associated annual depreciation expense as authorized additions to each respective UDC's revenue requirement and therefore recovered in rates. Authorized UDC capital expenditures can be on a cost-per-customer basis for certain specific variable cost plant additions (e.g., advanced meters) or a total estimated basis (e.g., billing system addition or measurement data collection software).[39]

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[37] Alternatively, PG&E or SCE could seek cost recovery in the Revenue Adjustment Proceeding (RAP), although the timing and frequency of future RAPs are uncertain. If the CPUC discontinues use of the RAP as a summary rate and revenue adjustment, SCE and PG&E propose to apply interest to these amounts and to recover them in the next rate case.

SDG&E would use its existing "Adjustment to Electric Distribution and Gas Margin Rates" mechanism that requires an advice letter filing in October each year and subsequent rate changes effective January 1 of the following year.

[38] Prior to any decision in Phase II of this proceeding, the utilities will likely need to undertake certain preliminary activities to ensure that any decision directing the utilities to deploy advance metering infrastructure can be implemented in a timely manner. These costs would include costs of evaluating technology options and conducting an RFP.

[39] SDG&E would use its existing "Adjustment to Electric Distribution and Gas Margin Rates" mechanism. Each year's recorded capital cost and associated depreciation cost will be recovered in the subsequent year via an annual advice letter filing, which adds these costs to the SDG&E's annual revenue requirements.

PG&E proposes to include capital expenditures authorized for approved tariffs and programs, experimental statewide pilot program and preparatory work necessary to timely implement decisions in R.02-06-001 in its next GRC.

6.1.4 Incentive Payments

Commission authorized programs that require UDC incentive payments will be recorded in the appropriate regulatory account.[40]

6.1.5 Revenue Shortfalls

There is a general consensus in the WGs to recover revenue shortfalls (e.g., due to load shifting, load reduction or bill credits) resulting from programs offered to bundled service customers from all bundled service customers through each UDC's existing balancing accounts.[41] With the existing balancing accounts, the UDCs believe it is unnecessary and, in fact, burdensome, to formally track costs and revenue shortfalls by tariff option/program (i.e., revenues received under the new tariff compared to revenues that would have been received under the otherwise-applicable tariff, assuming the same sales).

6.2 Attachment - Cost Incurred Prior to Commission Decision Authorizing Expenditures for R.02-06-001

The UDCs request that the CPUC authorize the recording of UDC costs incurred prior to the Phase I Decision in the Advanced Meter and Dynamic Response Account (AMDRA).

The details of the AMDRA, and the process by which the UDCs would file advice letters to establish the accounts, are as follows:

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[40] For SDG&E, these payments would be recorded directly in SDG&E's Energy Resource Recovery Account (ERRA) balancing account authorized in D.02-10-062. The ERRA describes the process to recover over/under collections. If the CPUC authorized programs for WG2 and WG3 involve UDC "capacity" incentive payments, then these payments will be estimated by the UDC and recovered through ERRA. The actual "capacity" incentive payments will be recorded in the ERRA balancing account and reconciled with the actual revenue collected and recorded and adjusted in the subsequent year's revenue requirements.

[41] For PG&E, the current Emergency Procurement Surcharge Balancing Account (ESPBA) and the Transition Revenue Accounting (TRA) mechanisms record procurement costs including retained generation costs. Additionally, the current TRA mechanism ensures that full collection of PG&E's authorized distribution, nuclear decommissioning, and public purpose program revenue requirements will continue even if changes in usage patterns from demand response programs produce revenue under-collections of the type described here. PG&E will seek similar accounting mechanisms once the TRA is no longer in place.

For SCE these payments would be recorded in the Procurement Related Obligations Account (PROACT). This mechanism assures full collection of SCE's authorized distribution, nuclear decommissioning, and public purpose program revenue requirements will continue even if changes in usage patterns from demand response programs produce revenue undercollections of the type described here. SCE will seek similar accounting mechanisms once the PROACT is no longer in place.

6.2.1 Costs to be included in the AMDRA

The costs that would be recorded should include all reasonable advance lead-time activities needed to continue to develop the tariffs and programs for WG2 and the statewide pilot before the CPUC issues its decision in Phase I. These costs would be capped at $1 million for all three UDCs combined ($450,000 for PG&E and SCE respectively, and $100,000 for SDG&E) for the statewide pilot. In other words, in addition to the prerequisite market research needed for the pilot, the UDCs would also seek to record the costs of various activities that of necessity are going to need to be continued over the next three months. These include: development of information, technology, and rate treatments; sample design; and any other activity needed to continue to refine and implement the pilot to ensure that it has a reasonable chance of being in place by the summer of 2003. The UDCs anticipate that in its Phase I decision, the CPUC will authorize expansion of the proposed balancing account to include further implementation costs, including capital costs as appropriate.

6.2.2 Language Required In Commission Ruling Authorizing Establishment of ADMRA

The UDCs suggest the following language (implementing the above concept) to be included in a Commission ruling authorizing the UDCs to establish these accounts. This level of detail is necessary for the UDCs to be in a position to quickly file uniform, complying advice letters:

"The UDCs shall each file advice letters establishing Advanced Metering and Demand Response Accounts (AMDRAs). The purpose of the AMDRAs is to record and recover the incremental, one-time set-up and on-going Operating and Maintenance (O&M) and Administrative and General (A&G) expenses incurred to implement, or in reasonable anticipation of implementing, the demand response programs adopted by the CPUC for both small customers (<200 kW) and large customers (>200 kW) in R. 02-06-001. These costs would be limited to a total of $1 million for the three UDCs combined ($450,000 for PG&E; $450,000 for SCE; and $100,000 for SDG&E) of costs incurred until the CPUC issues its Phase I decision in this proceeding and approves an accounting mechanism for additional expenditures necessary to implement its decision. The AMDRAs will apply to all customer classes, unless any class is specifically excluded by the CPUC. The revision dates applicable to the AMDRAs shall be as determined in each UDC's annual advice letter filing or as otherwise ordered by the CPUC. The AMDRAs will not have a rate component. The UDCs shall maintain their respective AMDRAs by making entries at the end of each month as follows:

a. A debit entry equal to the UDC's incremental one-time "set-up" and on-going O&M and A&G expenses for advance lead-time work necessary in anticipation of implementing the following programs being developed in Docket R.02-06-001 (1) the statewide pilot program (SPP) for small customers (under 200 kW), and (2) demand response tariffs and programs for large customers (greater than 200 kW) including,

1) Market research prerequisite to implementation of the SPP;

2) Development of the rate, information, and technology treatments for the various cells in the SPP;

3) Sample design for the various cells in the SPP;

4) Miscellaneous pilot design refinement and implementation activities reasonably necessary to ensure timely implementation of the SPP if approved by the CPUC in its Phase I decision;

5) Development of systems for billing and implementing tariffs and programs for large customers; and

6) Miscellaneous large customer tariff refinement and implementation activities reasonably necessary to ensure timely implementation of large customer tariffs and programs if approved by the CPUC in its Phase I decision.

b. A debit entry equal to the interest on the average of the balance at the beginning of the month and the balance after the above entry at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor."

6.2.3 Process To Establish The Accounts

The UDCs propose the following steps to establish the AMDRA:

- Ruling issued directing the UDCs to each file advice letters within five business days (assumes that the ruling contains language as comprehensive and detailed as that specified above)

- Parties have 10 days to comment on advice letters

- Advice letters become effective retroactive to the date of filing upon written approval of the Energy Division (does not contemplate resolution or CPUC decision).

SECTION 7 - METERING AND TECHNOLOGY SYSTEMS FOR SMALL CUSTOMERS (BELOW 200 KW)

7.1 Introduction and Summary

Small electricity customers, those with peak loads below 200 kW, represent approximately 70% of all the electricity delivered by California utilities. The CPUC's opening of this demand responsiveness proceeding to smaller customers reflects two basic beliefs. First, while smaller customers generally require more effort to reach on a broad basis, particularly when voluntary programs and initiatives are considered, they represent additional potential for state policy and regulations, utility programs, and third-party initiatives. This massive class of customers may contribute to a meaningful effect on the state's need for additional generating capacity, and on the overall reliability of the electricity system. Second, the technologies applied to small customers pose an opportunity for cross-fertilization into other market sectors.

A generally held perception about small customers is that the technology enabling them to be demand-responsive is either unavailable, or too costly in light of the limited benefits that can be seen from an individual small customer. This section is the work product of a subcommittee established by Working Group 3 in R.02-06-001, established to address both of these issues related to the current status of technologies available to small customers. Based on the relatively cursory review contained in this section, we can conclude that technologies, which support small customers in responding to demand responsiveness, exist today. The cost effectiveness of deploying those technologies and supporting infrastructure is as of the date of this report inconclusive. It is recommended that the CPUC go forward with a "Pilot" to validate the benefits of implementing demand response programs and rates. Additional functionality, such as for home security and home automation, while not included in most base case economic analyses, could further enhance the benefit stream to the residential user. Included in the costs of these systems are real-time metering capability, customer information systems, and an array of controls and switches that collectively provide a robust demand-responsiveness capability. With available and cost-effective technology, any small customer could be technologically-armed to participate in any of the demand responsiveness tariffs or programs under consideration in this proceeding.

A detailed discussion of the metering, communication, and control technologies available in the marketplace today, as well as their relevance to various tariffs and programs, are contained in sections of this section. Section 2 discusses the basic metering and communication technology requirements for demand responsiveness programs or tariffs. Section 3 discusses the network and other infrastructure requirements, and contains a recommendation for pursuing an open architecture in the future.

7.2 Technology Requirements

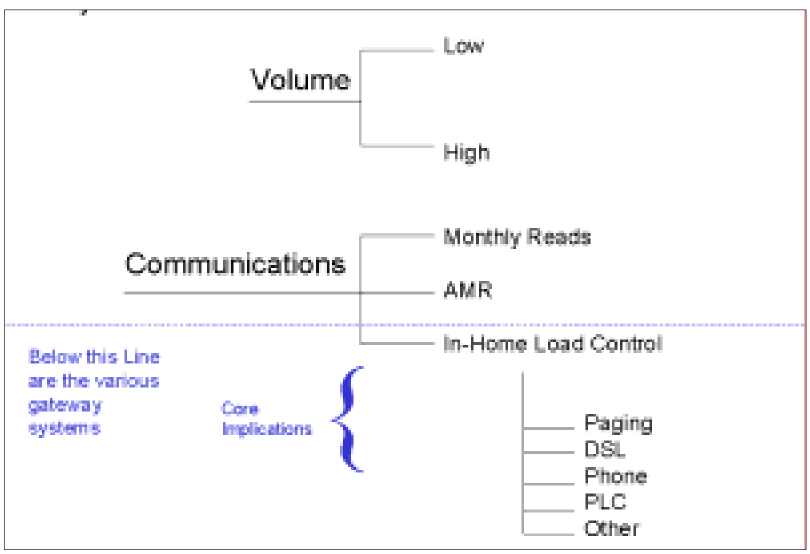
Tables 7-1 and 7-2 at the end of this section contain information regarding the minimum and recommended metering technology requirements and the communications technology requirements (respectively) for various forms of tariffs. These tables show that a relatively wide array of technologies could be mixed and matched to create workable systems for small customers.

Technology requirements are impacted by three significant considerations. The three considerations are:

- The customer volume (density) or number of sites where electricity usage will be measured,
- The role of the measurement function (communication requirements), and
- The control of devices inside the customer premises.

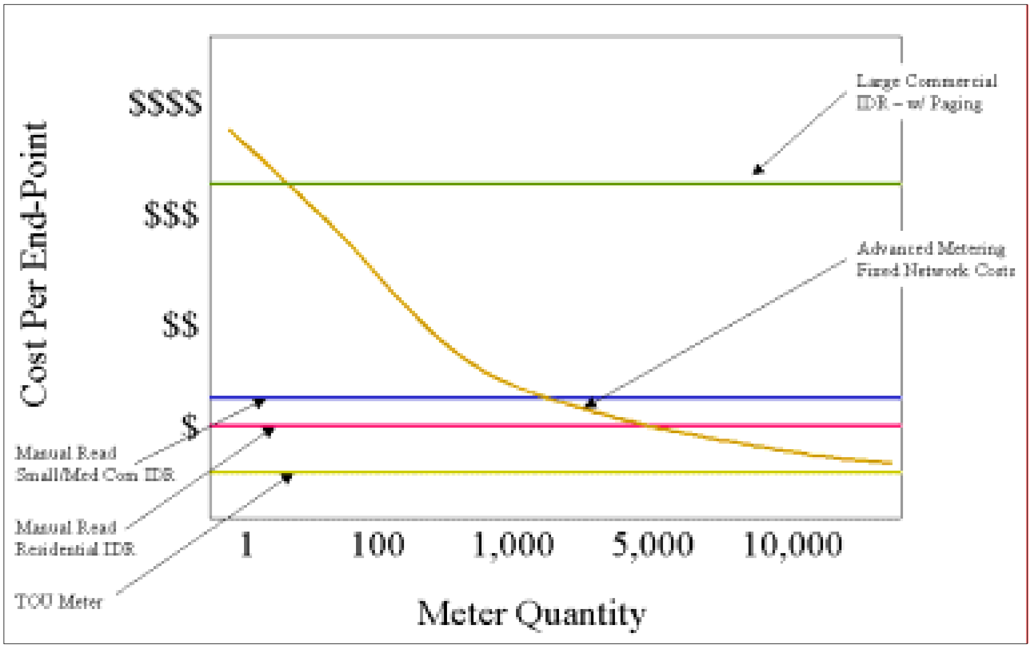
These key considerations are summarized in **Figure 7-1** below. The classical utility or measurement function, core business, changes as the system functionality increases from meter reading to in-home equipment control.

Figure 7-1. Key Considerations in DR Technology Requirements



The first consideration is the number of customers that are able and willing to participate (customer acceptance). Volume will affect the cost and type of metering and site-specific technology deployed. **Figure 7-2** illustrates the relationship between volume and costs (for metering) when planning for technology deployment options. As the number of meters purchased increases, the capital costs typically decrease on a per unit basis.

Figure 7-2. Advanced Metering: Cost/Volume Considerations



The Solid State TOU meter, although cost effective for recording time of use rates, cannot support more complicated rates. The typical IDR non-communicating meter, which can support complicated rates, has a more robust 128K of memory. Depending on the number of channels recorded, this can provide for 15-minute data for about 5 months of electricity usage. Both the TOU and IDR meters are normally read manually. In the high volume case, comparable meters and a combination of wired and wireless communication technologies can be leveraged to provide electricity usage sooner than the manually read meters. Given that demand response benefits are considered an integral component of the overall benefit for wide scale deployment, consumer inability and / or unwillingness to respond to price signals may not justify a system wide fixed network.

Density is an important factor as well, substantially affecting costs. For two reasons, higher density results in lower costs than lower density. First, many communication systems use concentrators shared by meters in a small geographic area; the cost per meter of such communication systems decreases as density increases. Second, a higher density of installations decreases the installation cost per site, since travel time per meter is reduced.

The second impact to technology selection is the role of the measurement function. This refers to whether or not the meter and the meter communication infrastructure serves in part, or in whole, as the customer messaging system in the event of a demand response episode. If the role of the measurement function is to only provide electricity usage data for billing purposes, then lower cost manual meter reading, or one-way wired or wireless data communication systems may be sufficient. If the role of the measurement function is to alert customers of a demand response episode and to provide in-home next day or same day energy usage, a more robust two-way communications infrastructure may be sufficient. The cost per site is increased as a result of additional communication functionality. One example may be the installation of a customer interface at the customer premise, communicating through the metering infrastructure. The schedule of the technology sub-team has not permitted the determination of these costs.

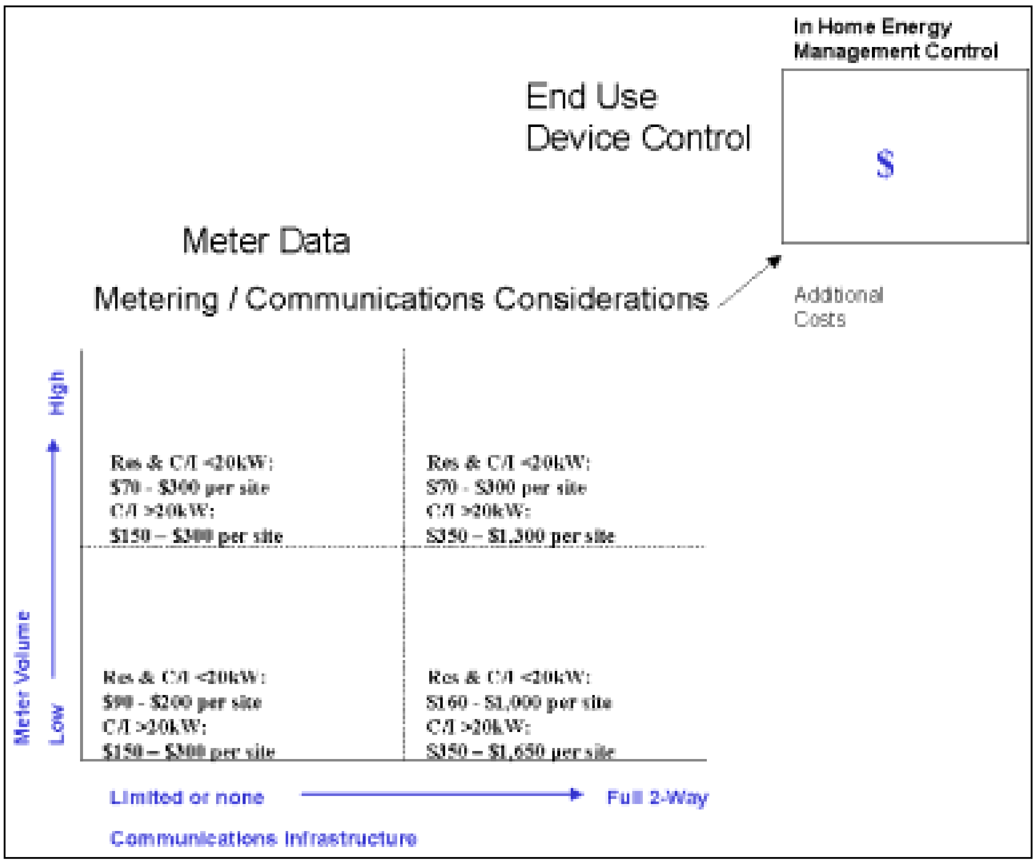
The third impact to technology requirements is the control of in-home appliances. A communication network capable of one or two-way communication is necessary if the meter measurement function is required to control in-home appliances. Some of the costs of in-home control devices are illustrated in **Figure 7-3**. (These device costs are incremental to those presented in Figure 7-4). There are alternatives to using the meter measurement function to control in-home devices.

Figure 7-3. Residential Load Control Technologies

Residential Load Control Technologies at a Glance	
Features / Characteristics	Approximate hardware costs
One-way switches and thermostats	
• Simple • Rigid • No feedback to ESP • No opportunity for consumer education • Support for time-of-use rates or real time pricing	Switches: $70 Thermostats: $150
Two-way thermostats	
• Preserves customer control • Web interface for home owners • Provides feedback to ESP • Curtailment somewhat less predictable than with one way devices • Support for time-of-use rates or real time pricing	$150 to $250 for volume purchases
Gateways	
• Benefits of Two-way thermostats • Value-added services for homeowners • Fee-based services for third parties • Rapid technology evolution (risk) • Automated meter reading • May require broadband Internet Access • Support for time-of-use rates or real time pricing	$100 to > $1,000

As noted in the above discussions, meter and meter-communications technology decisions depend on numerous factors. The technology depends on the level and cost-effectiveness of demand response. It depends on what functions are to be provided by the metering system, which could range from collecting billing data only, to communicating usage information to customers automatically to controlling appliances. The technology also depends on the role of the utility in each of these functions, with different roles implying different technology requirements. **Figure 7-4** illustrates the effects of volume, communication system complexity, and in-home controls. The costs provided are ranges based on current technologies. The cost of integrating energy consumption and end use device status data into utility systems is unclear. The determination of integration costs may be a consideration for phase 2 of the proceeding.

Figure 7-4. Metering/Communications Considerations



7.3 Infrastructure Requirements

In addition to the meters and devices required to implement dynamic tariffs, a variety of information systems are involved. These systems may be characterized as "back-office" systems and communications, including communications with customers, meters, and control devices.

These back office systems fall into three categories: pricing and billing, support systems for the many functions that support pricing and billing, and market systems, such as market settlement. The discussion below addresses these systems. It concludes with a recommendation that interfaces should comply with open architecture standards and that an open architecture standards effort be included in Phase 2 of this proceeding (R.02-06-001).

Planning for back office systems requires estimating the data flow requirements. The recommended frequency for collecting electricity usage for various tariffs is represented in 7-1. Table 7-1 characterizes the inbound electricity usage information necessary to build the measurement function back office system. Table 7-2 summarizes the outbound information requirements to support the various tariffs proposed in the current proceedings. The outbound messages signal the start of a demand response episode and are critical information to the utility back office billing system.

7.3.1 Back-Office Systems: Pricing and Billing

Back office systems support the two basic business functions involved in dynamic pricing: providing pricing to customers and recording their consumption response. The first function includes communicating all manner of information to customers needed to respond to the tariffs. Examples include prices, timing of peak or critical peak hours, notice of when critical peaks are dispatched, and price signals to systems that can control appliances or equipment automatically. This includes customer service functions such as enrolling customers in tariffs, tracking participation, and answering pricing and other program questions.

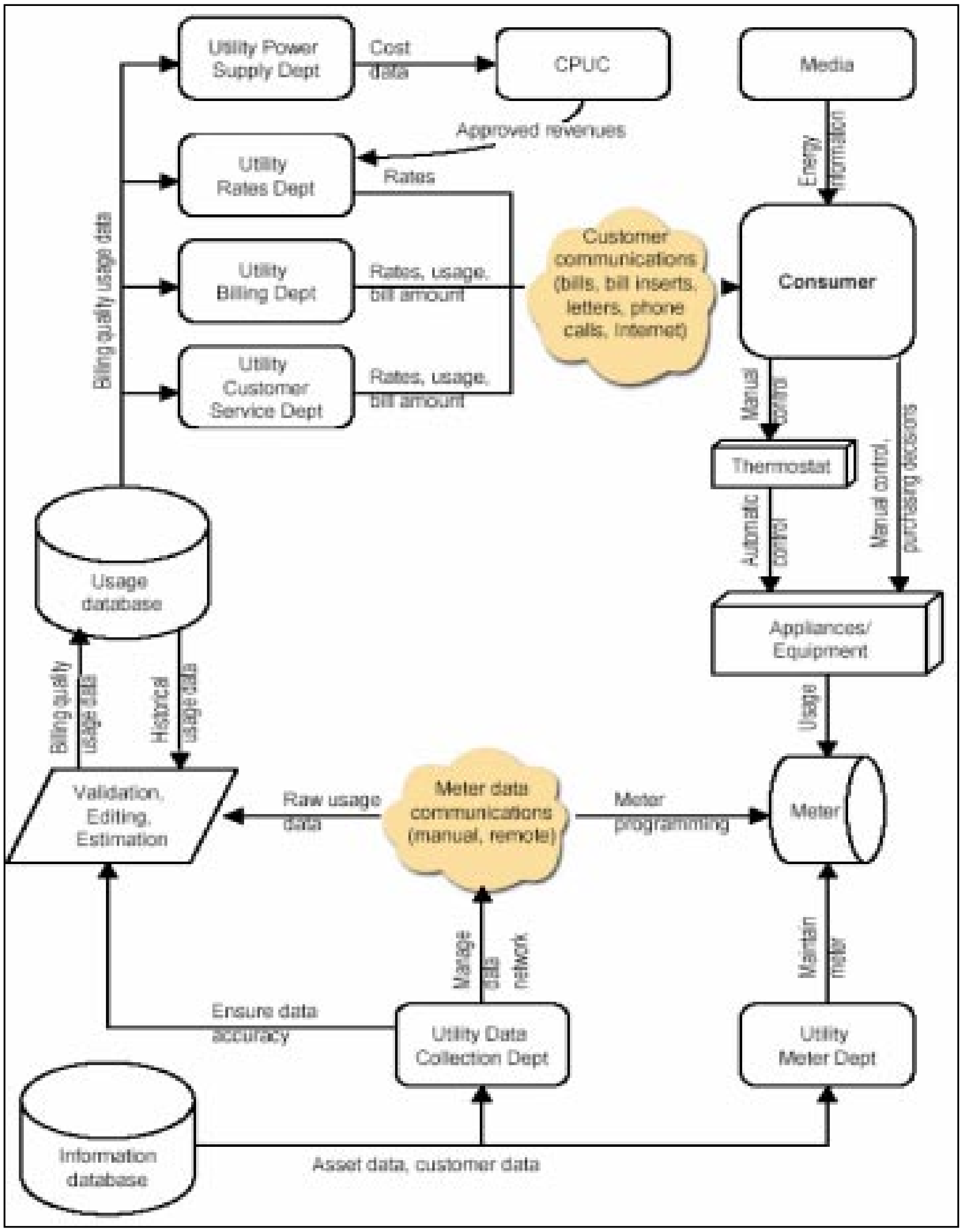
The second function is obtaining customer electricity usage and using it to bill the tariffs. The billing function includes the following systems that are directly involved in creating and sending a bill:

- Data collection (meter reading), including communications
- Data validation, editing, and estimation
- Bill calculation
- Bill transmittal to the customer

Carrying out the billing function also requires providing information in response to customer billing and usage inquiries, typically via customer service personnel.

The data flow for these two primary functions is shown in greatly simplified form below in **Figure 7-5**.

Figure 7-5. Information Flows for Pricing and Billing of Dynamic Tariffs



The data flow is the same for dynamic pricing as it is for old tariffs, but involves many more communications options (the two “clouds” in Figure 7-5).

With respect to customer communications, dynamic tariffs require more frequent information and more detailed information. Bills include usage by time period. Usage feedback is needed for tariffs such as critical peak pricing to enable customers to plan their response – by knowing a typical day’s usage during the hours that will be critical peak tomorrow – and to receive feedback on their response – by knowing how they did historically in response to pricing signals. Additional daily information can be provided assuming the necessary communications infrastructure is in place at some incremental cost. Notification is needed for tariffs that include dispatchable or frequently changing elements, such as a critical peak price. And new technologies, particularly the Internet, make it possible to provide more information, both via websites and via email.

With respect to usage data, dynamic tariffs require more frequent collection of usage data. Such collection must occur, typically, daily, with more frequent collection often desirable, at least on an optional basis.

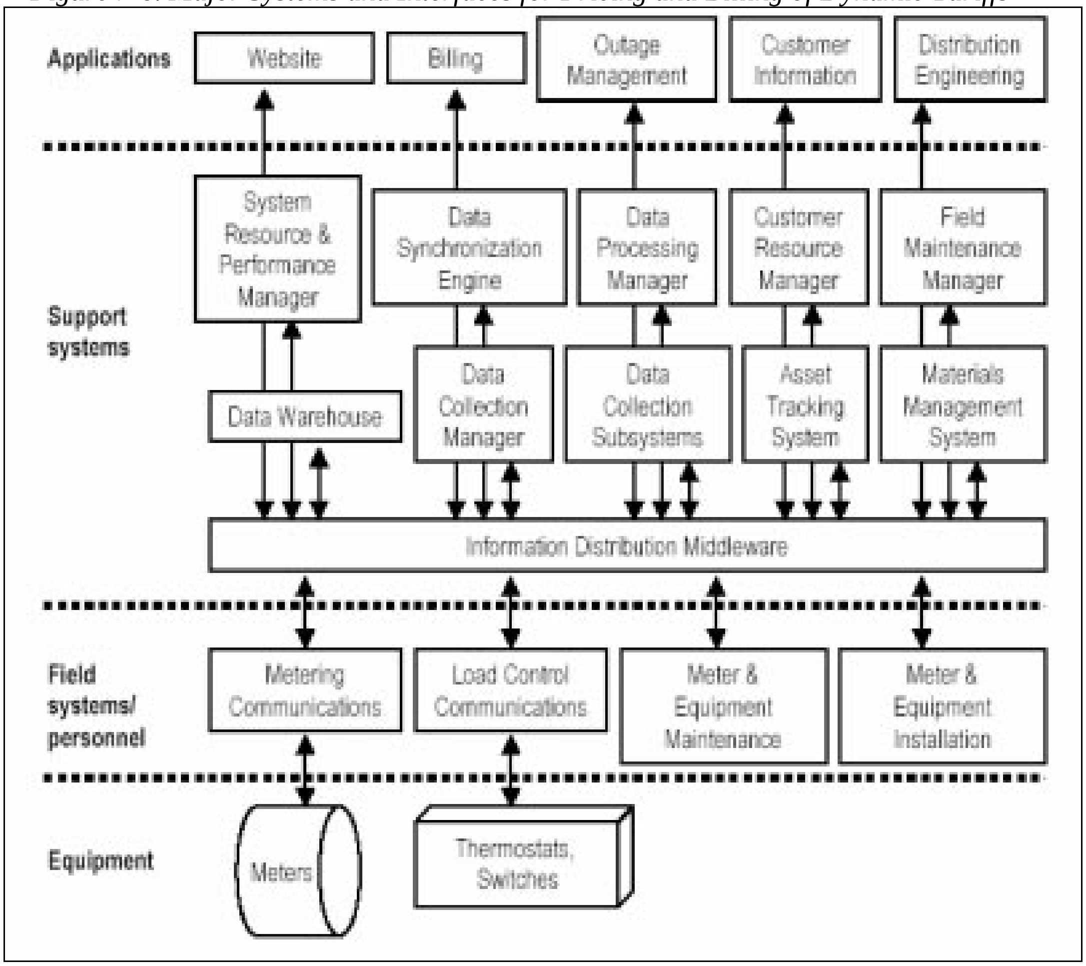
7.3.2 Back-Office Systems: Support Systems

To support the operation of the pricing and billing functions, numerous support systems are required as follows:

- Customer information system;
- Meter and communications asset management;
- Data collection management;
- Data processing and distribution; and,
- Meter and communications maintenance management, including trouble ticketing.

To pass data between these systems, the systems must be integrated, often involving integration to legacy utility systems. In addition, with multiple systems and multiple databases with overlapping elements, data synchronization is a critical and difficult task. The systems and their interconnections are shown in **Figure 7-6**. The cost of integrating these systems can be substantial and will vary between utilities.

Figure 7-6. Major Systems and Interfaces for Pricing and Billing of Dynamic Tariffs



7.3.3 Communications Systems

One of the major issues in a deployment of a response infrastructure, and one of the primary determinants of the cost of a deployment is the cost of the communication infrastructure required to support advanced metering and various demand control technologies required for maximum price elasticity. We can look at current and emerging technologies to make some recommendations regarding future work to specify these systems and create standard interfaces. In the meantime, approximately 10 million electric meters are currently in operation in the U.S. on fixed network communications systems, including several million using wireless technology and several million using power line carrier technology.

In order to facilitate the examination below, let us make two assumptions:

1. The infrastructure deployment will use some combination of communication technologies in order to support advanced metering, load control technologies, and other reasonable electric utility applications (outage detection, service disconnect, distribution control and so forth).

2. The communication technologies will use open standards (like Internet protocols) and the public infrastructure wherever reasonably possible and cost-effective.

Some consideration must be given to the selection of the technology based on the level of communication to support demand responsiveness programs and billing needs. Messages to the customer may be broadcast through many avenues available today. Pager, phone, radio, television, and in-home interactive displays provide a means of communicating with customers about demand shift or critical peak periods. In a more advanced system the customer could communicate directly over the Internet or through an in-home energy management system to end use devices, facilitating direct load control.

Electricity usage can be collected for billing purposes in several ways. In the simplest form an interval meter can provide electricity usage information in 15-minute increments, yet only be collected monthly. With the deployment of two-way communications, usage information can be collected up to several times a day. These diverse capabilities range in price and complexity. **Figure 7-7** illustrates costs per unit for using the metering data collection system as an optional platform for communicating with the utility customers. The costs in figure 3-3 do not include integration with existing utility systems or utility loaded costs for rate making.

Figure 7-7. Electricity Metering and Network Technologies

Electricity Metering and Network Technologies at a Glance	
Features / Characteristics	Approximate hardware costs per site
Manual Meter Reading	
• Least cost in low volume (Interval Metering) • Monthly billing & usage data • Delayed usage feedback • Support for time-of-use rates or real time pricing	Residential: $90 - $175 Commercial: $175 - $300
One-way communications network	
• Network provides broadcast and listening capability • Next day usage information (via Internet) • Support for time-of-use rates or real time pricing • Challenging integration with existing utility billing engines	Residential: $70 - $100 Commercial: $250 - $850
Two-way communications network	
• Daily or hourly usage information depending on system robustness (in-home display or Internet) • May support in home control technologies • Technology risks • Support for time-of-use rates or real time pricing • Challenging integration with existing utility billing engines *These costs do not include in-home controls, utility loading, or integration with utility billing systems.	Residential: $90 - $110 Commercial: $350 - $1650

7.3.3.1 Communications Architecture

Most advanced metering and demand response communications systems use a multi-layer communications architecture, typically defined as a Wide Area Network (WAN), and a Local Area Network (LAN). WANs are often some form of generally available public network, such as telephone, wireless phone, wireless data, or Internet. The direction of technology is to increase the penetration of the Internet into communication infrastructure. LANs extend from the gateway, router, or bridge between the WAN and the LAN to the end device (meter or control device). LANs are typically wireless, Ethernet, or power line carrier. The WAN/LAN interface device is typically called a gateway or concentrator.

Each layer of the communications system must support the necessary data throughput for the maximum expected number of devices. Devices can be connected directly to a WAN, such as for large commercial customer metering. However, in most cases, devices communicate through a LAN and gateway or concentrator. The reason is that the cost of a LAN communications module in a device is typically significantly lower than a WAN module.

The following considerations enter into selection of WAN and LAN technology:

- Cost of the WAN and LAN device and the associated reoccurring operational fees
- Minimum throughput required to support primary metering or control applications
- Maximum latency required to support metering or control applications
- Minimum availability (percent of uptime vs. downtime) of communication to each device
- Interface standards between the LAN and WAN
- Interface standards to metering and control devices
- Interface standards between the WAN and the utility's information technology infrastructure

7.3.3.2 WAN Candidates

Most publicly available WANs are reasonable for use in advanced metering and demand response communications. Public networks are characterized by open access, generally transparent pricing, and high reliability and availability. An area to consider is evolving public networks. New, digital networks are being installed for wireless data communications, such as GSM-GPRS and CDMA/1XRTT. In relying on these networks, implementing utilities should consider future deployment and operation plans of the public wireless data carriers.

7.3.3.3 LAN Candidates

LANs are typically either wireless, Ethernet or power line carrier. Standards are evolving for these. Some wireless LANs are proprietary. Current large-scale deployments of advanced metering network LANs use proprietary wireless LANs. Other wireless LANs are standards-based, such as IEEE's 802.11b (a.k.a., Wi-Fi or Wireless Fidelity) for wireless networks. While popular, Wi-Fi has cost and coverage issues that must be considered in its potential use. At this time, no significant installations of advanced metering or control technologies utilize Wi-Fi, so it has yet to be proven as a viable technology for advanced metering or control. Other standards are under development for wireless LANs (an example is 802.15). As with Wi-Fi, none of these standards-based wireless LANs have been used for advanced metering or load control in any significant way.

As with wireless LANs, both proprietary and standards-based power line LANs are available. Current large-scale deployments include examples of both. Similar to wireless LANs, cost and coverage or distance served must be considered. The largest deployments of power line carrier LANs for electric metering in the U.S. are proprietary. The standards-based power line LAN with the largest number of installations in Europe is one using the ANSI/EIA 709 standard known as LONWorks. Another power line standard used for electric metering is CEBus (EIA-IS-60). (An additional power line standard, X-10, is used by consumers but has not been used for electric metering.)

7.3.3.4 Implementing Open Architecture

This section has provided an overview of infrastructure issues regarding back-office and communication systems related to advanced metering and control for demand response. It identified the interfaces needed to enable interoperation by components and subsystems provided by various vendors. The work of actually defining these specifications and interfaces, however, will need to be done by future working groups or other standards organizations.

The benefits of specifying an open architecture will allow the market to create innovative solutions responding to the advanced metering and demand response control needs of Californians. The challenge will be to get the many approved standards to interoperate. This may help vendors reduce risk and develop solutions that will interoperate with solutions from other vendors. This should also allow utilities to benefit from the widest array of compatible products and solutions.

Specifying an open architecture whether through standards bodies or through publicly documented interfaces raises numerous complex questions. The Technology Subcommittee of WG3 has not had time to discuss these issues. For these reasons, while we recommend an open architecture be pursued, we also recommend that the definition and specifications of open architecture be deferred to Phase 2 of this proceeding.

Table 7-1. Metering/Measuring Requirements by Tariff Type

Tariff or Rate Treatment	**Metering /Measurement Requirements**	**Data Type**	**Data Collection Frequency**	**Data Frequency**		**Minimum Data Available (see note 2) to:**	**Comments**
				Audit Function	Enhanced Communication		
Time of use	Usage during predetermined time bins (see note 1)	Kwh read by bin	Minimum: Predetermined bins monthly Recommended: predetermined bins, daily	Minimum : Monthly	Minimum: Daily Recommended: hourly so customer usage patterns can be changed if necessary	billing entity, utility and customer	Flexibility to change the tariff is a technology-dependent issue, see note 2. TOU meter would require field visits to reprogram meter for tariff changes.
Real Time Pricing (one or two pat)	Usage coincident with market price or system changes. Recommend: Hourly updates issue at 15 minutes before the hour.	Kwh read per hourly interval with associated rate in effect	Hourly	Minimum : Monthly	Minimum: Daily Recommended: hourly so customer usage patterns can be changed if necessary	billing entity, utility & customer messaging system	Rate in effect must accompany usage to account for loss of price change data at end use point and conflicts in billing.
Critical Peak Pricing (both CPP-F and CPP-V)	Usage during CP Period	Kwh read by period	Hourly	Minimum : Monthly	Minimum: Daily Recommended: hourly so cust. usage patterns can be changed if necessary	billing entity, utility & customer messaging system	Need ability to change CP period daily. Helpful to have positive verification it was received and acted upon at every end point
Demand Bidding	Demand available to be controlled (pre) And actually controlled (post)	Kwh during control period	Hourly	Minimum : Monthly	Minimum: Daily Recommended: Hourly	billing entity, utility, customer & demand bidder's systems	
Emergency Demand Bidding and Control	Demand available to be controlled (pre) And actually controlled (post)	Kwh during control period & KW upon request	Hourly	Minimum : Monthly	15 seconds (ISO standard for aggregated load)	billing entity, utility, customer & demand bidder's systems	

Notes:
(1) Need ability to change periods periodically without significant cost
(2) Fees may apply for additional data delivery above the minimum; there are numerous ways to handle data delivery, some more acceptable to the recipients. We recommend that these also be tested.
(3) In all timed usage tariff's a means of checking and resetting clocks in meters remotely is also essential and should be in all of the above.
(4) Data Frequency is defined as: How often data is collected and stored in a system (usage interval)
(5) Data Latency is defined as: How long the data takes from the time it is collected to the time it is available to the messaging or communications systems and the role of the measurement function as auditor or communications facilitator.
(6) Functionality recommendations are contingent upon the metering technology meeting both the functional requirements and a cost benefit analysis for the incremental cost and benefit over the minimum requirements.

Table 7-2. Message or Communication System Requirements by Tariff Type

Tariff or Rate Treatment	**Communication Requirements**	**Messaging Type**	**Message Frequency** (see notes 7, 9)	**Minimum Message Receipt Requirements** (see notes 8,9)	**Access Method** (see note 9)
Time of use	Billing usage by bin	Bill, online , or email access	*Minimum:* Monthly (via Bill) *Recommended:* Daily.	*Recommended:* Daily messages should arrive within 30 minutes of being sent	*Minimum:* Monthly (via Bill) *Recommended:* Available online or via electronic email/messaging
Real Time Pricing (one or two part)	Periodic Price and usage signals to customer or their designees: Price/kwh, Kwh usage, time Recommend using a 10 day rolling average consumption for the period to project usage and price if no action is taken, permitting a customer decision to be made with more information	Signal to display device (fax, email, website)	*Minimum:* Hourly Information (or to match market) sent 1 day ahead *Recommended:* display price data and a start and stop time for the price point. The price should be known enough in advance to make the decision	Depends upon design. *Recommended:* Day ahead messages should arrive within 3-5 minutes of being sent, all day-ahead messages arrive by 5pm the day before	Electronically by both customers and their designees AND via monthly summary bill.
Critical Peak Pricing	Whether Critical Peak Price is activated—send information to customer or their designee Critical peak price time, level and duration	Mass media, online access, or signal to display device (fax, pager, website)	*Minimum:* Day ahead	Depends upon design. *Recommended:* Day ahead messages should arrive within 3-5 minutes of being sent, all day-ahead messages arrive by 5pm the day before	Electronically by both customers and their designees AND via monthly summary bill.
Demand Bidding	Demand available to be controlled (pre) And actually controlled (post) Status of control action	Signal to display device (fax email, website)	Periodically (to match bid profile and control action) *Recommended:* Day ahead	Depends upon design, Day ahead messages should arrive within 3-5 minutes of being sent.	Control entity, ISO or utility: pre-control kw available, post-control kw captured .
Emergency Demand Bidding and Control	Controlling entity, utility and ISO: Demand available to be controlled (pre) And actually controlled (post) Customer: control action status, override status	Signal to display device (pager, fax, email)	Hourly Data (to match market) *Recommended:* Day ahead	Depends upon design, Day ahead messages should arrive within 3-5 minutes of being sent.	Control entity, ISO or utility: pre-control kw available, post-control kw captured

Notes:
(7) Message Frequency is defined as: How often the information is to be sent to recipients
(8) Message Latency is defined as: How long the message takes from the time it is sent to the time it arrives at the display device of the intended recipient
(9) Functionality recommendations are contingent upon the messaging technology meeting both the functional requirements and a cost benefit analysis for the incremental cost and benefit over the minimum requirements.

APPENDIX A - DISSENTS

A.1 Dissenting Comments of the Utility Reform Network (TURN)

Given the direction by the WG3 facilitator that dissent is limited to four pages, TURN will elaborate on these and other points in its comments on the workshop report.

TURN has actively participated in the CPUC's Working Group 3 (WG3) process in an attempt to provide some moderation to the vision of universal deployment of advanced meters and dynamic pricing for small customers. While TURN's appreciates the report's authors incorporating many of TURN's comments and edits, it should be clear that TURN does not support universal deployment of advanced meters. There may be specific applications of dynamic pricing and advanced meters that provide meaningful demand reduction and participant savings for small customers, but that investigation has been sacrificed in this proceeding for an "all or nothing" approach. This increases both the risk and potential that parties will get it wrong--and once again saddle ratepayers with a multi-billion dollar mistake.

Having said that, TURN is not opposed to the statewide pilot program (SPP) and hopes that it produces meaningful data that will steer decision-makers in the right direction. However, the CPUC should not take an "all or nothing" approach but should include a third alternative. If results from the SPP show there are only specific applications of advanced metering and dynamic tariffs that are cost effective, to pursue those instead of leaping into a multi billion dollar decision to invest in system deployment. Further, in Phase II the CPUC should evaluate alternative methods of cost recovery for advanced metering. As suggested by ALJ Ruling Regarding Disposition of Proceeding (App. 99-06-033, et. al, October 18, 2002), the CPUC should resolve issues that were the subject of the last revenue cycle services hearing and evaluation of meter ownership and cost recovery issues in Phase II of this proceeding.

A.1.1 It is Unlikely That Most Residential Customers Can Benefit From a Time Differentiated Rate Design

TURN believes that most small customers will not benefit from time of use pricing. TURN has made a preliminary analysis of TOU issues for residential customers, using PG&E data from its 1996 residential appliance saturation study (RASS). This analysis showed that close to 60% of PG&E's residential customers use less than 6,000 kWh a year and on average use less than 300 kWh on-peak in Zone T and less than 400 kWh for the rest of the system. Assuming a meter charge of $3 per month, and a rate differential of 20 cents between on and off peak hours, the customers would have to shift 180 kWh relative to the class average to break even. These smaller customers have better load patterns relative to the class average and have already shifted 30 kWh away from the peak. Thus, 60% of the PG&E's customers would have to shift close to half (150 kWh) of their on-peak energy usage just to pay for a $3 month meter charge. This paradox shows that smaller customers that might benefit from time differentiated pricing due to their load shapes don't have enough load to shift to pay for the meters.

In many ways, this was the reason that Puget Sound Energy's TOU experiment failed.[42] Customers could not produce enough savings to pay for the meter and the meter cost was only $1/month. However, meters will most likely cost more than this. For instance, PG&E's current E-7 time of use meter charge is $3.50/month or $1.50/month with an approximate $271 meter installation charge. This charge is for a TOU meter that only costs approximately $75 off the shelf, but is close to tripled when the utility includes it in rate base due to the numerous adders and loaders involved in utility ratemaking. Initial meter costs ($90-$175, Fig. 3-3) alone could escalate to over a few hundreds dollars, and that is before one- or two-way communication devices, or necessary utility infrastructure.

While the Report mentions high fixed charges as a barrier to incentives to demand response (and conservation), it does not adequately mention that metering costs are traditionally allocated chiefly to small customers as customer costs and utilities prefer to recover these costs as fixed customer charges—which will clearly dampen customer incentives to shift load.

A.1.2 PG&E's Business Case Analysis is a Preliminary Analysis.

TURN appreciates PG&E's efforts to supply the WG3 with a business case analysis and understands that additional business case analysis for all three utilities in will occur in Phase II. The business case analysis is preliminary in nature and should only lead to the conclusion that universal deployment of advanced meters is a very uncertain decision at this point. It shows that utility system benefits (without demand reduction) are not sufficient to justify the costs of the program.[43] Demand response benefits, whose range of uncertainty is enormous, must supplement utility system benefits to be cost effective. Thus, there is enormous risk as well as uncertainty involved in the decision of universal deployment.

In 1997, the CPUC was faced with the exact same decision, when Southern California Edison proposed a system wide installation of automatic meter reading (AMR) system (Comments of SCE on Metering and Billing Strategies Identified in D. 96-10-075, 12/20/96). The AMR

[42] Metering proponents in WG3 contended that PSE's TOU experiment failed because there was only a $0.016/kWh on- to off-peak price differential—which reflected a doubling of the PSE forecast of on- to off-peak price differential in the spot market. The California Energy Commission also forecasts a minimal price differential between off- and on-peak market clearing prices in the next ten years (CEC Energy Outlook, 2002-2012, pp. 35-36). Price differentials between off- and on-peak market clearing prices is forecast to be no greater than $0.015/kWh over the next ten years. This places California's utilities in a similar situation (relative to PSE) of attempting to pass on market clearing prices in TOU rates that has little price volatility.

[43] TURN will elaborate on the specifics of PG&E business case cost effectiveness at greater length in its comments to the WG3 Report.

system costs were greater than system benefits without inclusion of price signal and direct access benefits—that ranged from $300 million to over $1 billion. Because of the uncertainty over the utility's proposed benefits and the enormous investment involved, the CPUC decided the risk was best left with Edison's shareholders, who could bear all costs and reap all benefits (D. 97-05-039).

It important to note that D. 97-05-039 was made in an environment significantly more conducive to benefiting from advanced metering than the current environment--and the CPUC still decided ratepayers should not bear the risk. At that time, affecting the market clearing price for electricity was significantly more important than it is today—utilities had to procure 100% of their energy from the power exchange. Today, utilities use the spot market similarly to the early 1990s when it was used to merely pass on short-term deficits and surpluses between utilities. When advanced metering made the most sense in California, the CPUC still felt that the risk of that investment did not warrant recovery in rates. It should maintain that same caution in evaluating current advanced metering proposals.

A.1.3 California Already Has Many Tools to Achieve Demand Reduction that Should Not Be Ignored or Thrown Away

One deficiency of the WG3 Report is its failure to address and recognize what tools California already has to achieve demand response from small customers. First, inverted tier rates have been a useful and important tool in reducing overall energy usage for close to 25 years. The CPUC has long recognized that a) inverted tiers provide meaningful conservation signals to customers and b) conservation is a laudable goal. In addition, there is considerable evidence showing inverted tier rates also provide associated peak demand reductions—a more valuable resource than mere load shifting. One study showed that implementation of an inverted tier rate for Puget Sound Energy dropped energy usage per customer by 25% over a 20-year period (Lazar, 2002). This, along with California's mild weather and mandated building efficiency standards, contribute to the fact that California has the lowest energy usage per capita in the United States.[44]

The WG3 Report also does not mention residential air conditioner (A/C) cycling programs. While not an "advanced" technology it has been enormously successful and provided some of the most reliable demand reduction in the nation. Edison has had a successful A/C cycling program for decades. It is dispatched before the industrial interruptible demand reduction at a fraction of industrial interruptible program costs. The independent system operator has always dispatched it before other demand response programs, especially those that are based on price response. On average it results in 2.3 kW/unit of reliable demand response compared

[44] California's low per capita energy usage should not be overlooked in evaluating the ability of small customers to shift loads. TOU rates have typically only benefited larger users (i.e., PG&E's E-7 customers consume double the residential class average yearly usage), and the only residential critical peak-price program is operated in Florida,

to current forecasts of 0.9 kW/unit in demand reduction SDG&E's more expensive Smart Thermostat Program.

TURN also disagrees with many of the WG3 metering proponents who have characterized the program as "destructive" because customers cannot override the program, thus hindering customer choice. Customers choose by signing up for the program and can choose again to get off the program if they are not satisfied. While TURN is generally in favor of customer choice, it has also painfully learned a whole host of evils can very easily be hidden in the supposed benefits of "customer choice" (i.e., deregulation).

The CPUC has asked for WG3 to provide it with some alternatives for a "quick win" for the summer of 2003. TURN believes the greatest potential for a "quick win" in residential demand response (total MW) can be achieved by directing the utilities (Edison) to ramp up existing air conditioner cycling programs and require PG&E to report back to the CPUC on its status of implementing an A/C cycling program as directed by D. 01-04-006.

The CPUC should also direct Edison to step up implementation of its A/C cycling program. While Edison has plans to ramp up its residential air conditioner cycling program for 2003, it has delayed 2002 implementation due to concerns it's current spending for load control programs might reach the cap authorized in D. 01-04-006 (App. 02-05-004, SCE-5, Vol. 3, pp. 63). Ensuring that Edison aggressively pursues implementing and expanding its residential air conditioner cycling program will assist the CPUC in achieving its "quick win" goals for demand response in the summer of 2003.

A.1.4 The CPUC Should Address Meter Ownership Issues Outlined in D. 99-12-046 in Phase II of this Proceeding

On October 18, 2002 the CPUC issued an ALJ Ruling (Ruling of ALJ Wetzell in A. 99-06-033, et. al, p. 4) asking parties how the CPUC should dispose of its suspended proceeding on revenue cycle services. In that ruling, the ALJ asked parties whether the issue of incumbent utilities' competitive advantage in new meter installations should be reviewed in either the revenue cycle services proceeding, or this advanced metering proceeding. TURN recommends addressing this issue in Phase II of this advanced metering proceeding. Phase II of this proceeding is an appropriate forum for addressing issues associated with meter ownership and cost recovery, and evaluating the elimination of competitive advantage of incumbent utilities regarding new meter installations.

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where average residential customers consume 17,000 kWh/yr. California residential customers on average consume 6,000 kWh/yr.

A.2 ORA Recommended Improvements to the Statewide Pilot Program

ORA thanks WG3 leadership for facilitating the design of the SPP, testing the viability of dynamic pricing for small customers. ORA recommends the SPP be modified to be purely voluntary with a sign-up bonus[45]. Second, ORA believe the SPP must include an hourly pricing treatment. ORA recommends WG1 approve the SPP as modified below.

A.2.1 The SPP Should be Purely Voluntary

At this point it has yet to be decided whether a large scale rollout would be voluntary, mandatory, or some combination of the two where treatment varies by customer group or climate zone. Given this uncertainty and apparent legislative intent[46] that the pilot be voluntary, the SPP should test for both possibilities. Only a voluntary pilot will provide both the information on cost effectiveness necessary to evaluate a mandatory rollout and information about customer preference necessary to market a voluntary program.

The SPP, as currently designed, is an Opt-Out program[47]. The SPP is intended to test the response of customers in the event of a mandatory switch of customers to dynamic pricing tariffs[48]. The report often uses the term 'Voluntary Opt-Out' to describe the program, which is implemented by moving participants onto the tariff and allowing them to exit the tariff only if they complain, or after the first months of the test are over[49]. ORA does not consider this to be a Voluntary pilot as currently designed.

ORA believes offering customers a monetary incentive to participate is superior to mandatory participation. An incentive of approximately $100 would add about 3 percent to the cost of the SPP, and would still preserve the statistical and legal integrity of the test. ORA believes incentive payments would help achieve the stated objectives[50] of the SPP better than the SPP as currently designed, and would not affect customer behavior once they

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[45] Might be as high as $100 per participant.

[46] ORA believes a voluntary program is more in line with the expressed desire of the legislature as stated in Senate Bill (SB) 1388. The Public Utilities Code in implementing SB 1388 states that "no customer is required to participate in a pilot study." (Code §393(c)(3)). ORA also notes Sunne McPeak's remarks at the WG 1 meeting of 12/4/02: "it is mandatory that we deploy that choice to consumers for base load and peak load and that we phase it into the customer. It is voluntary to the customer to opt in. That is my personal approach " (TR 120402 317 page 42).

[47] In the table showing the different treatment cells, the report restricts itself to the term 'Opt-Out'. In the text of the report, the term 'Voluntary Opt-Out' is used.

[48] Page 43: "The primary purpose of SPP is to simulate the effects of large-scale rollout of time-varying prices".

[49] Page 22 of the report describes how other 'Voluntary Opt-Out' programs have been implemented in the past: "These experiments were set up to have mandatory placement on time-of-use rates by customers, but customers who complained about the programs were typically allowed to opt out of the experiments."

[50] Page 34: "An important secondary objective is to assess customer ***preferences*** for rates and other treatments such as control technologies and feedback about the impact of shifting energy use patterns" (italics added).

are on the tariff[51]. There are precedents in other industries for this approach. For example, cellular phone companies offer customers free cell phones in order to entice them to switch[52].

The SPP as currently designed tests customer acceptance, but not customer preference[53]. The difference between acceptance and preference is that a customer might accept a tariff even though they would prefer another tariff, because the information costs and transaction costs of making the switch are greater than the benefits of switching. The report refers to this as customer inertia, implying that the customers are passively remaining on their old tariff. In fact, customers are making an active costs/benefits analysis relating to transaction costs when accepting one rate even though they prefer another[54]. The SPP should measure customer preference, in keeping with its own objectives, as well as customer acceptance. ORA's modified SPP measures customer preference by examining Opt-In rates, and still measures customer acceptance by examining Opt-Out rates.

A.2.2 The Pilot Should Include an Hourly Pricing Treatment

The purpose of a pilot is not only to lend support to ideas already thought to work, but also to test ideas whose feasibility is unclear. WG3 has declined to include an hourly pricing (HP) treatment in the pilot, on the presupposition that it would not be a reasonable alternative to CPP or TOU rates. ORA believes that WG3 has prejudged the outcome of a viable alternative to CPP, TOU, and flat rates, and therefore recommends that the SPP be modified to include an HP treatment in addition to the current SPP's TOU treatment[55].

ORA recommends adding an hourly pricing treatment similar to SDG&E's HPO, in the same scale as TOU treatments in the SPP. In order to give the IOUs time to prepare their billing systems for hourly pricing, ORA recommends that the hourly pricing treatment begin in October 2003, in coordination with the IOUs' efforts in WG2 to develop a production scale hourly pricing tariff. WG3 has almost no data on HP treatments, which would come closer to

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[51] The signing bonus compensates participants for the information and transaction costs incurred in making the switch. The signing bonus is not intended to make participants whole, thus it does not violate rule 9 of the lists of threats to internal validity found on page 60.

[52] The cell phone model is an example of a model for both the pilot and for an eventual rollout of meters (should that prove cost effective). A customer voluntarily receives initial infrastructure, or some other incentive, for free, and in return is required to take service on a particular tariff for a certain number of months.

[53] Page 21 of the report states: "…customer preferences for and customer acceptance of tariffs are very different." It attributes the difference to customer inertia, when in fact the difference is due to the information and transaction costs of switching tariffs. The same paragraph states that 'neutral choice' options measure acceptance, when in fact they measure preference. The report in general fails to make a sufficient distinction between customer acceptance, customer preference, inertia, and information and transaction costs.

[54] The SPP as modified by ORA can calculate in monetary terms the difference between customer preference and customer acceptance. By offering potential participants varying incentives to participate in the pilot, we can judge by their acceptance rates the information and transaction costs, as well as the value to customers of not having to switch tariffs. These values can be included in the costs/benefits analysis supporting the decision to implement dynamic pricing.

[55] Pages 38 and 39: "Ideally, one would design a pilot to test a variety of time-varying pricing options, including: … Day-ahead and hour-ahead real-time pricing rates, in which the price of electricity varies on an hourly basis."

giving customers the actual price signals that the utilities and market participants face. Modifying the SPP as ORA recommends will help rectify this problem.

A.2.2.1 Advantages of Hourly Pricing over Critical Peak Pricing

Hourly pricing should not be ruled out a priori as inappropriate for residential customers. According to forecasts of wholesale prices the next four or five years, price variation by TOU period in California will not be much higher than they were in Puget Sound's territory. However, there may be temporary price spikes that are hidden by the level of aggregation involved in TOU rates and even CPP rates. According to studies, TOU rates only capture about 10 percent of the real-time price variation, whereas a day-ahead HP can capture 60 to 70 percent of it. For these reasons, hourly pricing should be given serious consideration for the residential class and only rejected when empirical data from the SPP shows it to be not cost effective.

A legitimate question is whether CPP sufficiently improves the price signal relative to simple TOU pricing to serve as an adequate substitute for HP. Prior to implementation of the SPP, the answer to this question is unclear. A CPP with a critical peak long enough to not merely shift load to other hours, which potentially could become peak hours, may be too long to adequately reflect variation in underlying wholesale prices.

Claims that an HP is too complicated are unfounded. Where technology is installed to assist with price response, a CPP and an HP are exactly equal. Where technology is not present, an HP is actually easier to understand for customers than a CPP is. A CPP requires that customers be on the lookout for 100 hours where the price will be high, whereas an HP allows customers to internalize the fact that every day, prices will be higher in peak hours than at other times. A customer on CPP can only save money by waiting for and responding to the CPP signal, whereas an HP customer can save money by shifting load away from peak on every day and on every hour.

A.2.3 Conclusion

The results and experience gained from the pilot programs will guide the three agencies in future decisions that determine the eventual magnitude of meter rollouts and dynamic pricing programs. ORA believes the voluntary proposal put forth herein can accomplish WG3 articulated goals.

A.3 PG&E Comments on the Invensys and IMServ Pilot Proposals

A.3.1 PG&E Comments on Invensys Pilot Proposal

Invensys proposes an alternate method of implementing a technology based rate treatment. The technology treatment proposed by Invensys is virtually identical, in concept, to that proposed in the statewide pricing pilot (SPP) with the exception that Invensys proposes to dispatch loads other than air conditioning using a prototype “gateway” technology which Invensys claims is ripe for consideration for deployment in this pilot.

PG&E does not support the Invensys proposal for the following reasons:

PG&E remains interested in keeping pilot costs to a minimum while maximizing the information gained on demand response. Key to this objective is minimizing the number of pilot customers and technology treatments required by the pilot. With this in mind, the proposed SPP targets primarily air-conditioning load since that load remains the largest contributor to peak demand. The UDCs have numerous other programs that address other end-use loads such as lighting, pool pumps and other household loads. Hot water heaters are not a focus in the SPP because most are fueled by natural gas in the UDCs’ service territories. Nevertheless, in the SPP, the UDCs agreed to consider control of other loads to the extent the technology is "off the shelf", costs are not prohibitive, and the technologies can be implemented by the UDCs in accordance with the proposed implementation schedule. As a result, the objectives of the Invensys pilot are already included in the SPP and the Invensys pilot would therefore add costs without significantly adding insight into technology-assisted customer demand responsiveness to dynamic pricing.

Secondly, the focus of the Invensys pilot is on the dispatch and direct UDC control of many customer loads. As such, the recommended pilot would not focus on gaining insights on customer responses to dynamic pricing, but would require more complex rate structures and incentive payments. PG&E does not believe that a pilot testing an incentive payment rate structure would provide any additional information on customer response to dynamic price signals.

Thirdly, no CPUC-ordered demand response pilot of this type should be implemented based on the deployment of or selection of a single manufacturer’s technology. Neither PG&E nor the CPUC has any basis for concluding that the Invensys technology option is superior or inferior to any of the other alternative technologies. PG&E therefore believes it would be imprudent for the CPUC or UDCs to order any vendor-specific pilot or selection without first conducting a proper technological assessment. PG&E believes that the Invensys pilot objectives can be accomplished in a vendor-neutral way through the SPP and that the issue of technology choices is better left to Phase II when there is more time to consider all technology options and after we have obtained better information regarding customer response.

In conclusion, the Invensys pilot will not add significant value to what the SPP will already provide regarding the impact of technology on demand response. If ordered to implement the Invensys proposal, PG&E believes that trying to develop this pilot would be a significant diversion of resources from the SPP and jeopardize the prospects of implementing either pilot in time for June 2003.

A.3.2 PG&E Comments on IMServ T&D Control Pilot Proposal

In its proposal, IMServ proposes a pilot program that would offer customers transmission and distribution (T&D) credits for reducing T&D costs. PG&E does not support this proposal and raises the following observations, issues and concerns:

By agreement of WG3, PG&E believes the purpose of the recommended statewide pricing pilot (SPP) is to gain critically needed information on the demand response of customers necessary to identify the magnitude of peak load reductions, and hence generation and power price savings achievable through dynamic pricing. The focus of the IMServ proposed pilot appears not to be on gaining a better understanding of customer demand responsiveness. Instead it proposes a pay-for performance load reduction program targeted on a small segment of the benefits, specifically local T&D congestion and costs. As such, the IMServ proposed pilot unnecessarily adds cost and rate complexity not required to accomplish the primary goal of determining price responsiveness, and peak load generation savings, associated with dynamic pricing. PG&E does not suggest that demand response is not capable of producing some T&D savings. These savings, however, are not the primary driver or purpose of these programs.

Moreover, customer bill reductions already capture demand related T&D cost reductions. Through rates and tariffs customers reducing demand or moving demand off-peak already benefit from reductions in distribution costs as a result of reduced peak or noncoincident demands and no additional incentives, as proposed by this pilot are considered appropriate or necessary.

Fourth, the proposal does not explain critical details needed for implementation such as how T&D benefits would be determined and priced. It would take considerable additional time to determine this and other key aspects of the IMServ proposal.

In conclusion, the IMServ pilot is peripheral to the main thrust of the OIR and will add little value to the SPP. If ordered to implement the IMServ proposal, PG&E believes that trying to develop this pilot would be a significant diversion of resources from the SPP and jeopardize the prospects of implementing either pilot in time for June 2003.

A.4 SCE Comments on the Invensys and IMServ Pilot Proposals

A.4.1 SCE Commentary on Invensys Pilot Proposal

Invensys proposes an alternate method of implementing a technology based rate treatment. The technology treatment proposed by Invensys is virtually identical, in concept, to that proposed by the UDC's with the exception that Invensys proposes to dispatch other loads (other than a/c) using a prototype gateway which Invensys claims is ripe for consideration for deployment in this pilot.

With regard to the choice of the Invensys system vs. the countless other options advertised by vendors, SCE does not have any information to support that this technology option is superior or inferior to any of the other alternatives. It would be imprudent and unfair for the CPUC or UDC to essentially make any vendor specific award without first conducting a technological assessment. SCE understands that the issue of technology choices is better left to phase 2 when there is more time to consider all technology options and after we have obtained better information regarding customer response.

Invensys also claims that their implementation costs are less than the UDC pilot proposals however they offer no information that would support that claim and there is no other information source to seek validation. Invensys also ignores the fact the UDC pilots are intended to first and foremost provide the data necessary to measure and evaluate load response based on a variety of conditions. Thus, the pilot technology options proposed by the UDC's are not necessarily representative of the costs of the technology that could be implemented on a larger scale.

In the interest of keeping pilot costs to a minimum while maximizing demand response, SCE has opted to target a/c load since that load remains the the largest contributer to peak demand. The UDC's have numerous other programs that focus on lighting, pool pumps and other household loads. Hot water heaters are mostly fueled by natural gas in SCE's service territory. Nevertheless, the UDC's will consider control of other loads to the extent the technology is "off the shelf" , costs are not prohibitive, and it can be implemented by the UDC's in accordance with the proposed implementation schedule.

Finally, Invensys offers a new rate structure that has no bearing on the technology treatment they propose. The Invensys proposal offers a reward rather than a penalty for load reduction. SCE acknowledges that there are numerous rate treatments that can be considered however, in the interest of keeping pilot costs to a minimum, we need to limit our rate treatments.

A.4.2 SCE Commentary on IMServ T&D Control Pilot Proposal

In its proposal, IMServ proposes a pilot program that would offer customers T&D credits for reducing T&D costs. SCE does not support this proposal and raises the following observations, issues and concerns:

1. As written, the proposal does not contain a sufficient level of information for SCE to assess the feasibility of designing and implementing such a program, which couples a new T&D incentive based program with specialized meters that utilize "PSWG open architecture technology".

2. The CPUC has an open OII/OIR (R99-10-0-25) where the value of deferred T&D investments will be valued. SCE believes it would be pre-mature and inappropriate to work towards development of a T&D incentive-based program at this time.

3. Customer Bill Reductions Already Capture Cost Reductions: Customers reducing demand or moving demand off-peak already benefit from reductions in distribution costs as a result of reduced peak or non-coincident demands.

APPENDIX B - PG&E BUSINESS CASE PRESENTATIONS

B.1 PG&E Business Case Presentation

PG&E

Advanced Metering Business Case
Customers Less Than 200 KW

October 31, 2002

Working Group 3

Sacramento, CA

R.02-06-001

PG&E Advanced Metering Business Case

Operational Business Case Summary

Key Assumptions:

- "Universal" 5-year Rollout beginning April, 2004; Reach 90% of meters (4,735,000 Electric, 3,265,000 Gas, 8,000,000 Total) in the combined service area
- Daily Time of Use (TOU) and Critical Peak Pricing (CPP) reads for Electric meters; Monthly reads for Gas meters
- Representative Proven Technologies; Indicative Costs

Financial Results:		**15-year NPV**
• Total Deployment Costs		$ 1,861 M
• Operational Benefits		(781) M
• Operational Gap	(pre-tax)	$ 1,080 M*

*15-year after-tax NPV of the operational gap is $640 M.
The levelized incremental annual pre-tax revenue requirement is approximately $120 M per year, when operational benefits are realized as an offset to the deployment costs.

Internal sensitivity analysis indicates a range of $562 to $808 M of after-tax operational gap ($948 to $1,364 M pre-tax), based on Energy Act treatment, cost contingencies and assumed AMI meter lives.

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Advanced Metering Business Case

Total Deployment Costs

	15-year NPV
AMR Meters / Modules	**$ 798 M**
Network Capital	**242 M**
Network and Data Services	**735 M**
Other Costs	**86 M**
(pre-tax)	**$1,861 M***

AMR Meters / Modules — $ 798 M

- Lowest cost between new integrated AMR meter or reconditioned existing meter with AMR module
- Vendor interviews, validated with other utilities in deployment

Network Capital — 242 M

- Universal deployment of representative AMR technology
- Reach 90% of electric and gas meters in the combined service area

Network and Data Services — 735 M

- Meter reading and information processing
- Daily TOU and CPP reads for electric; monthly reads for gas

Other Costs — 86 M

- Project management / systems integration costs
- Network power and pole attachment costs
- Meter maintenance, including battery replacements

(pre-tax) **$1,861 M***

*15-year after-tax NPV of the operational deployment costs $ 1,103 M

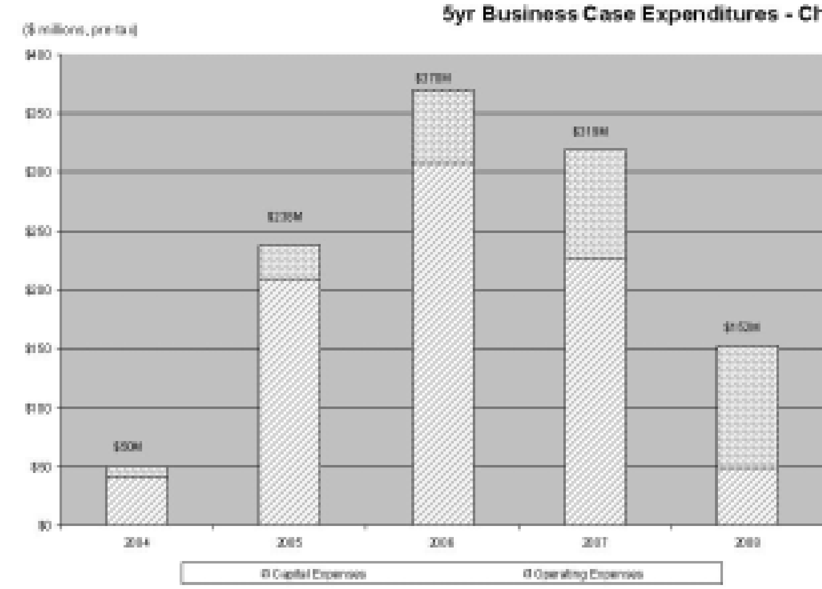
Advanced Metering Business Case

5yr Business Case Expenditures - Table

	2004	2005	2006	2007	2008	5yr Totals
Existing Meters Converted / Year	263,000	1,964,000	2,862,000	2,047,000	389,000	7,525,000
Annual System Load Growth	76,000	102,000	98,000	100,000	99,000	475,000
Total Meters Automated	339,000	2,066,000	2,960,000	2,147,000	488,000	8,000,000
(In $ millions, pre-tax)						
Capital Expenditures						
AMR meters / modules	$23	$159	$235	$172	$38	$627
Network	17	50	72	55	11	205
Sub-Total: capital expenditures	$40	$209	$307	$227	$49	$832
Operating Expenses						
Network & Data Services	$2	$16	$47	$78	$95	$238
Systems integration & other costs	8	13	16	14	8	59
Sub-Total: operating expenses	$10	$29	$63	$92	$103	$297
Total Expenditures	$50	$238	$370	$319	$152	$1,129

Advanced Metering Business Case

5yr Business Case Expenditures - Chart



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Advanced Metering Business Case

Operational Benefits

	15-year NPV
Tax Laws	$ 196 M
• HR 3090 (already enacted, for deployment through 1/1/2005) • Energy Act – HR4/S517 (anticipated passage in 2002) • Benefit of early write-off of existing meters tax basis	
Meter Reading	558 M
• Reduction of manual scheduled meter reads • Reduction of manual Change of Party reads as well as high bill re-reads	
Revenue Cycle	19 M
• Reduced call center traffic (due to misreads, delayed and estimated bills) • Reduced costs to issue re-bills • Improved cash flow due to meter reading timeliness	
Field Operations & Transformer Load Management	8 M
• Reduction in dispatched "single lights out" trips • Improved ability to manage significant outages and reduce outage duration • Reductions in required transformer expenditures and related electrical losses	
(pre-tax)	$ 781 M*

*15-year after-tax NPV of the operational benefits $ 463 M

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Advanced Metering Business Case

Additional Operational Benefits Considered

Unaccounted for energy (UFE)

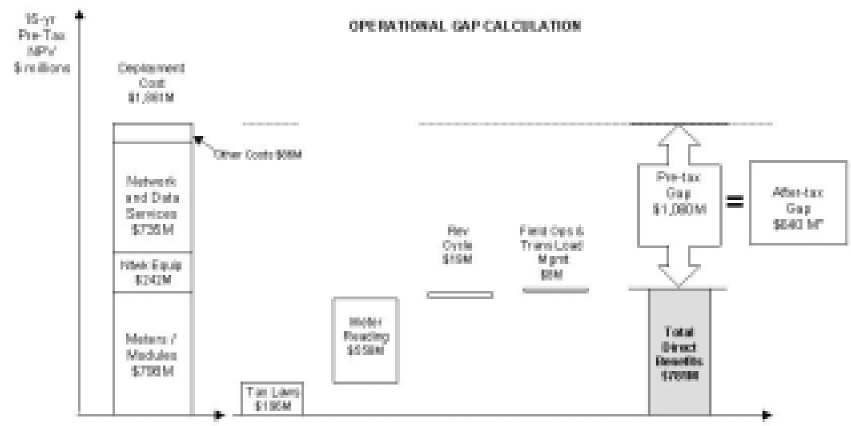
Two additional categories considered in some utility business cases are improved metering accuracy and reduced meter tampering and energy theft. A fully deployed AMR system would reduce UFE. This reduction represents the transfer of money from one group of ratepayers to another group. For instance, if a greater percentage of meters are running accurately, then a greater percentage of customers are paying their fair share of the authorized revenue requirement.

Transmission, distribution and generation benefits

Benefit estimates are included in the discussion of resource/societal benefits presented by Charles River Associates. These benefits are a direct function of the degree of customer response.

Advanced Metering Business Case

Operational Gap



*Internal sensitivity analysis indicates a range of $562 to $808 M of after-tax operational gap ($948 to $1,364 M pre-tax).

B.2 CRA Dynamic Pricing Cost-Benefit Analysis for PG&E

Benefits Of Dynamic Pricing For PG&E's Customers Under 200 kW

Charles River Associates

October 31, 2002
Working Group 3
Sacramento, CA

Framework For Assessing Benefits

- **Rate Type**
  - We considered TOU and CPP/TOU pricing options
- **Customer Response**
  - We reviewed the past quarter century of experiments and field trials with TOU pricing and CPP/TOU pricing
- **Avoided Costs**
  - We used the CEC's projections
- **Meter Deployment Strategy/Rate Participation**
  - 90% coverage/20% opt-out
- **Time horizon**
  - We used 15 years

2

Our Methodology

- Used the standard practice methodology (SPM) to estimate benefits of load shifting across multiple perspectives, including total resource cost (TRC), ratepayer impact measure (RIM), and participating customer (PT) tests
- Conducted the analysis for four climate zones for residential customers (R, S, T and X)
- Used PG&E's billing and load shape data to estimate the flat prices that correspond to the existing five-tiered inverted rate structure
- Conducted the analysis for three different rate classes
  - E-1 (residential)
  - A-1 (<20 kW commercial)
  - A-10 (>20 kW, < 200 kW commercial)

3

Four PG&E Climate Zones

4

Key Assumptions

- **Price Elasticities of Demand**
  - Lower-end = -.1 for own price elasticity of peak usage in Central Valley residences (less in milder climates and small commercial)
  - Higher-end = -.3
- **Marginal Costs of Capacity**
  - Lower-end = $43 /kW-year in year one
  - Higher-end = $100 /kW-year in year one
- **Opt-Out Rate**
  - Lower-end = 20% for TOU, 40% for CPP
  - Higher-end = 10% for TOU, 20% for CPP

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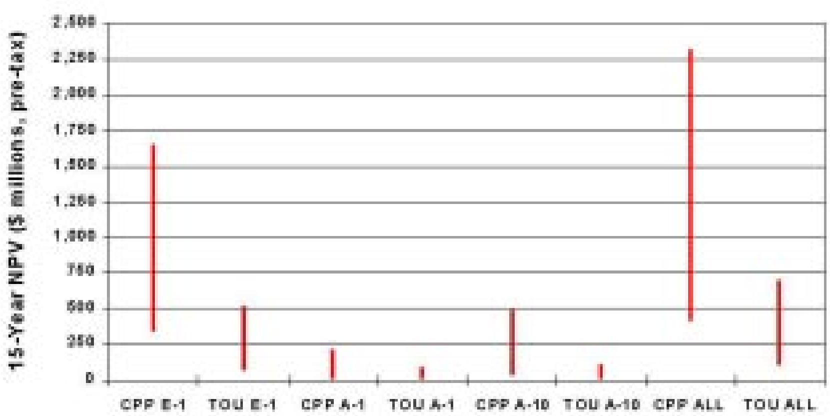
Commodity Benefits Vary Greatly Due To Uncertainty in Key Assumptions

Total Resource Costs (TRC) Gross Benefits*



* Does not include T&D benefits or Lost Revenues

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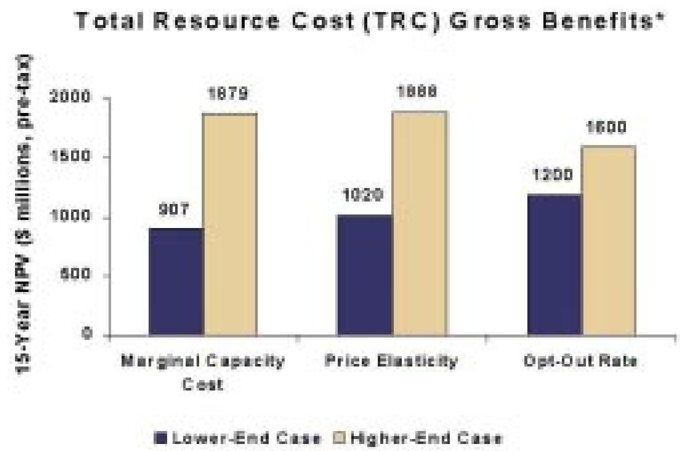
Sensitivity Analysis Of The Commodity Benefits Of The CPP/TOU Rate



* Does not include T&D benefits or Lost Revenues

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Other Factors In Decision Making

- The previous slides have shown the commodity benefits of load shifting from a TRC perspective
- In addition, there will be transmission and distribution (T&D) benefits from a TRC perspective
- These combined TRC benefits would guide state policymaking
- PG&E may experience lost revenues with the new rate designs, and will need to evaluate benefits from the RIM perspective

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Combined Benefits Of CPP/TOU Pricing (15-Year NVP Pre-Tax in $ Millions)

	TRC Commodity Benefits (A)	TRC T&D* Benefits (B)	Total TRC Benefits (A+B)	Lost Revenue (C)	RIM Benefits (A+B)-(C)
Lower-End Case	$418	$143	$561	$316	$245
Higher-End Case	$2,298	$339	$2,637	$923	$1,714

*T&D benefits only attainable to the extent load shift occurs and persists if customers respond to dynamic rates

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Conclusions

- Absent a pilot, there is considerable uncertainty in the estimated benefits
- CPP/TOU pricing dominates TOU pricing
- CPP/TOU TRC benefits range from $561 million to $2,637 million
- In addition, lost revenues range from $316 million to $923 million, and would have to be recoverable by PG&E
- To make an informed decision about AMI deployment, we need to conduct a rigorous and well-designed pilot that can give us a better estimate of the benefits of time-varying pricing

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