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Quantifying the Benefits Of Dynamic Pricing In the Mass Market

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EXECUTIVE SUMMARY

The purpose of this report is to lay out a methodology for quantifying the benefits to customers and utilities of dynamic pricing programs. We illustrate the methodology with specific examples using a suite of models called the Pricing Impact Simulation Model (PRISM) Suite. This suite extends a model that was derived from the experimental data collected in the 2003-2005 California Statewide Pricing Pilot (SPP).[1] Such benefits are critical inputs for evaluating the cost-effectiveness of potential advanced metering infrastructure (AMI) deployments. Although PRISM was developed in California, the basic model can be adapted to conditions in other parts of North America after adjustments have been made for climatic, socio-demographic, rate and load shape characteristics. The PRISM Suite includes a model for estimating demand response impacts and a model for estimating financial benefits to customers and utilities.

- In Section I, we describe the PRISM Impacts Model in terms of its inputs and output. The Impacts Model is an Excel spreadsheet where the inputs are the existing and dynamic pricing rates and utility-specific weather data, load shapes, and central air conditioning (CAC) saturations, and the output is the customer-level demand response including the customer bill savings.
- In Section II, we describe the PRISM Benefits Model in terms of inputs and outputs. The Benefits Model is part of the same Excel spreadsheet where the inputs are the customer-level demand response (from the Impacts Model), a forecast of customer participation rates, and estimated capacity costs, energy costs, and transmission and distribution (T&D) costs. The output breaks down the utility benefits into avoided capacity costs, avoided energy costs, avoided T&D costs, and reduced wholesale market prices.
- In Section III, we describe the standard benefit-cost tests that are used to evaluate demand-side programs in the electric utility industry. This section provides a simple roadmap showing where to obtain estimates of benefits and costs for each test. The PRISM Suite provides the benefits estimates for use in these tests.
- In Section IV, we discuss the hedging cost premium embedded in static rates, show how to quantify the hedging premium present in flat rates, and provide estimates of hedging cost premiums in two areas of PJM. We also suggest how this premium can be offered as a credit to customers taking service under a dynamic pricing structure as a method for making dynamic pricing more attractive to customers.
- In Section V, we describe the benefits of dynamic pricing under alternative market structures—deregulated distribution companies and vertically integrated utilities—and discuss how the benefits realized under dynamic pricing vary depending on market structure.
- In Section VI, we describe traditional methods that are currently used for achieving demand response such as direct load control (DLC) programs and time-of-use (TOU) rates. We also compare DLC and TOU programs to demand response programs incorporating advanced metering and dynamic rates. DLC systems do not motivate customer response, and they raise equity concerns because there is no direct relationship between benefits achieved and incentives paid. TOU rates are relatively inefficient and ineffective compared to critical peak pricing (CPP) or real-time pricing (RTP).

[1] Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot." March 16, 2005.

- This report also includes Appendices A through H. In Appendices A and B, we discuss the worksheets in the PRISM Impacts Model and the PRISM Benefits Model. In Appendix C, we summarize the SPP. In Appendix D, we include a presentation that provides an overview of the PRISM model, "Developing Critical Peak Pricing Tariffs with the PRISM Software." In Appendix E, we provide a summary of results from dynamic pricing pilot programs. In Appendix F, we provide an analysis of the impacts of dynamic pricing on low-income customers. In Appendix G, we provide a summary of information technologies that can promote demand response. In Appendix H, we provide a more detailed explanation of the elasticity estimates included in the PRISM model. The appendices, together with the PRISM model, are available online on the Edison Electric Institute (EEI) website. To access these documents, please visit www.eei.org/ami

Throughout the paper, we use a variety of rates including CPP, peak-time rebate (PTR), and TOU to demonstrate how benefits vary based on rate design. Also, even within a CPP rate, benefits can vary significantly depending on the value of the critical peak price as well as the number of program participants. Both of these factors are critical.

Ultimately, the widespread use of AMI and dynamic pricing will require that the net benefits of such an investment are positive. We show with illustrative examples how the PRISM Suite of models can be used to estimate the benefit side of the equation. For the whole picture, the cost side of the equation will also need to be completed. Since the cost side tends to be very utility-specific, we have left that part of the analysis to individual readers.

We also show how giving customers on dynamic pricing a credit equal to the avoided hedging cost can make dynamic pricing rates more attractive to customers. Further, we show that dynamic pricing can be usefully deployed in both restructured and non-restructured states. Finally, by providing comparative information on DLC and TOU programs, we make the point that if the sole objective is to achieve demand response, a variety of alternative mechanisms is available and can be easily factored into the analysis.

INTRODUCTION

Dynamic pricing of electricity is receiving increasing attention in the industry today because it holds the potential for significantly improving the efficiency of electricity markets in both restructured and non-restructured states. Under dynamic pricing, customers pay lower prices for all but, say, 100 hours of the year during which time they pay significantly higher prices.[2] Thus, they have a strong incentive for using less power when it is most expensive to generate and deliver, thereby helping to bring demand and supply into equilibrium at lower prices than would otherwise be the case. This becomes increasingly important when demand is increasing faster than supply and demand-side options. The North American Electric Reliability Council estimates that reserve margins in many regions will fall below acceptable levels within the next few years. Inability to balance supply and demand was one of the major factors in the California energy crisis several years ago; dynamic pricing would have been helpful in avoiding or mitigating the severe impacts of that crisis because it could have lowered demand during very high-priced periods.

This paper provides an overview of the basic steps in quantifying the benefits of dynamic pricing for the mass market. The paper is written for utilities and regulatory commissions that are developing and reviewing advanced metering infrastructure (AMI) business cases. The mass market consists of residential and small commercial and industrial (C&I) customers that generally have peak demands of 200 kW or less. These customers represent about 40 percent of the energy consumption in the United States and contribute a somewhat larger share of peak demand because their load factor is lower than the system average. The examples used throughout this paper focus on residential customers.

A widely recognized prerequisite to the provision of dynamic pricing is the installation of “smart” or advanced meters, most often requiring AMI. However, the level of expected customer participation will influence the optimal AMI configuration.[3] For example, a drive-by meter reading system involving automatic meter reading (AMR) capable of interval reading might be the most cost-effective technology if only a small percentage of customers is expected to participate in a dynamic pricing program. A full-featured AMI system will be more cost-effective if a high percentage of customer participation is expected.[4] Depending on the locale and features of the technology, AMI investment costs range from $100 to $200 per smart meter. A large fraction of that cost (ranging from 50 percent to 90 percent) can be recovered through traditional utility operational benefits such as avoided meter reading costs, faster outage detection, improved customer service, and better management of connects and disconnects.

The system-wide deployment of smart meters creates a platform for providing “smart prices” to customers. By smart prices we mean retail prices that reflect the varying cost of electricity in the wholesale market. Such prices have the potential for inducing demand response (DR) that would yield additional benefits in the form of cost savings associated with the reduced need for peaking generation capacity, lower peaking energy generation costs, and lower transmission and distribution costs. Assuming that the operational benefits of AMI are not sufficient to cover its costs, the benefits from DR can “bridge the gap,” making the net present

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[2] The number of hours when lower prices are in effect will vary with the specifics of the rate design.

[3] EEI Whitepaper: “Deciding on Smart Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005.” Prepared by Plexus Research, September 2006.

[4] Unlike automated meter reading (AMR), which uses mobile, drive-by systems and cannot be used for dynamic pricing, AMI uses a smart digital meter that is capable of interval measurements and two-way communication between the premise and the utility.

value (NPV) from a long-lived metering investment positive, thereby yielding a viable business case.[5] Therefore, when conducting a benefit-cost analysis of AMI, both the operational benefits and the dynamic pricing-induced demand response benefits need to be considered.

In addition, in today's environment where many regions of the country are predicting short-run capacity shortages, DR can reduce peak demand, thereby playing a critical role in mitigating these shortages and contributing to resource adequacy and reliability.

This paper specifically addresses the primary benefit to the utility (or load serving entity (LSE)) of a dynamic pricing rate design, which is the dollar value of reduced MWs resulting from demand response, and the primary short-term benefit to the customer, which is the bill savings resulting from demand response. In the long run, the customer will derive additional benefits because utility costs will decline as customers are served more efficiently, a point that is often overlooked in the current debate on the costs and benefits of dynamic pricing. This paper does not address the operational benefits of AMI since those are discussed in a companion volume.[6]

We also address the secondary benefits such as lower energy generation costs (or fewer wholesale power purchases) and lower T&D costs. We note that in many cases there will be no environmental benefits associated with DR, in part because the primary effects are peak clipping and load shifting and not energy conservation. Therefore, the environmental benefit is dependent on which plants run more when the load is shifted. Utilities with base load nuclear plants would likely realize environmental benefits from DR, but utilities with base load coal plants would not. The environmental benefit of DR is utility-specific. Finally, we review the standard benefit-cost tests for evaluating utility investments in demand-side programs—participant, total resource cost, rate impact, utility cost, and societal cost tests.[7]

We illustrate the methodology for quantifying the benefits to customers and utilities of dynamic pricing programs with specific examples using a suite of models called the Pricing Impact Simulation Model (PRISM) Suite. This suite extends a model that was derived from the experimental data collected in the 2003-2005 California Statewide Pricing Pilot (SPP).[8] Although PRISM was developed in California, the basic model can be adapted to conditions in other parts of North America after adjustments have been made for climatic, socio-demographic, rate, and load shape characteristics. The PRISM Suite includes a model for estimating demand response impacts and a model for estimating financial benefits to customers and utilities.

We expanded the PRISM model to provide not only the load shape changes associated with various forms of dynamic pricing but also the full range of utility benefits resulting from dynamic pricing, including: capacity benefits, energy savings benefits (i.e., lower energy generation costs or avoided wholesale power purchases), transmission benefits, distribution benefits, and price mitigation benefits. We also expanded the model so that individual customer bill impacts can be simulated. Details about the PRISM Suite are included in Appendices A, B, and D.[9]

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5 For evaluating the cost-effectiveness of AMI from an operational perspective (i.e., pre-"demand response"), see EEI Whitepaper: "Deciding on Smart Meters: The Technology Implications of Section 1252 of the Energy Policy Act of 2005." Prepared by Plexus Research, September 2006.

6 Ibid.

7 California Standard Practice Manual: Economic Analysis of Demand-Response Programs and Projects. July 2002.

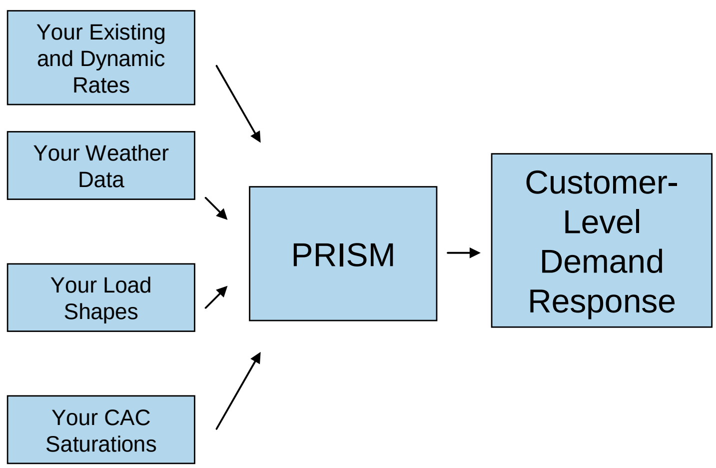
8 Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot." March 16, 2005.

9 See Appendix D for a description of the PRISM model.

In this paper, we focus on residential customers (for ease of exposition), but the methodology is perfectly general and would also apply to other classes of customers. To make the benefits analysis concrete, we have developed illustrative results for a mid-sized utility that is located on the east coast. At this utility, we assume that the typical residential customer uses about 1,000 kWh per month during the summer, and the saturation of central air conditioning (CAC) is about 75 percent. We have also developed stylized existing and new rates, load shapes and weather conditions for this utility. All of these variables influence the forecasts from PRISM and highlight an important capability of the model, which is the transferability of its impact estimates across geographic regions. As a companion to this report, we are providing the PRISM Suite, an enhanced version of the original PRISM model, as a standalone Excel spreadsheet. The model is available online on the EEI website. To access the model, please visit www.eei.org/ami

As shown in Figure 1, the first step in the PRISM Suite is the Impacts Model, which is used to estimate the "unit impact" or change in consumption per customer resulting from dynamic pricing. This is the customer-level demand response or the "impact" estimate.

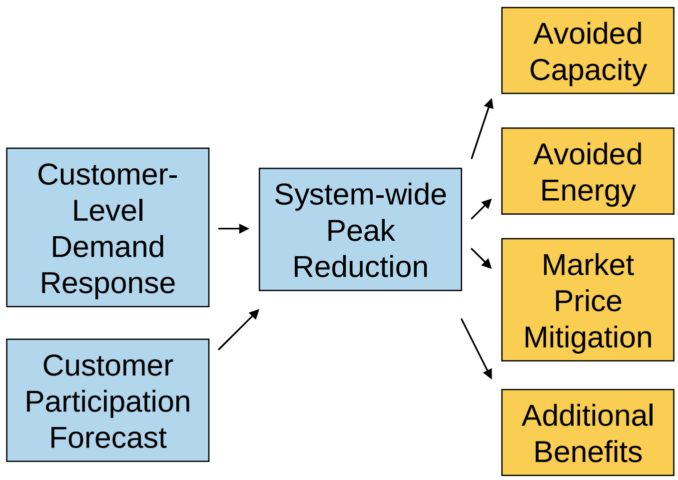
Figure 1: PRISM Suite Impacts Model: Inputs and Output



The second step in PRISM is to quantify the primary and secondary benefits associated with dynamic pricing on a per-customer basis and system-wide basis. As shown in Figure 2, the PRISM Suite Benefits Model provides estimates of the following benefits: avoided wholesale capacity costs, avoided wholesale energy costs, market price mitigation, and other avoided costs (e.g., transmission and distribution costs). The per-customer impacts from the PRISM Suite Impacts Model and a market penetration forecast provide the inputs to the benefits estimation. In this example, we include the mitigation of wholesale prices brought about by DR as a benefit. However, there is much debate about whether price mitigation is a "true" benefit for use in a benefit-cost test because it is a transfer payment from generators to consumers, which is not a component of benefits in the standard utility benefit-cost tests. The analyst can decide whether to include or exclude the price mitigation benefit value for both the utility and its customers. In our analysis for Mid-Atlantic Distributed Resources Initiative (MADRI), we included this benefit.[10]

[10] *The Brattle Group*, "Quantifying the benefit of demand response for PJM," prepared for PJM Interconnection LLC and MADRI, January 2007.

Figure 2: PRISM Suite Benefits Model: Inputs and Outputs



The demand curves and price elasticities in PRISM are based on a large data set that includes responses of approximately 2,500 customers over a two-year period to various forms of dynamic pricing, a wide variety of weather conditions, and a range of socio-demographic factors. Specifically, the data set used to estimate the customer demand curves and price elasticities in PRISM is based on a rigorous experimental design. Therefore, although much of the data needed for the PRISM model are utility-specific, the elasticity estimates—although the best results available—are not utility-specific. Over time, as results become available from other pilot programs, the PRISM elasticities can be updated to reflect new information from other regions. However, we believe that the California-based elasticity estimates in PRISM are extremely robust, unlikely to change significantly, and represent the best available estimates at this time.

Besides California's experiment, we are aware of several other dynamic pricing pilots that are currently underway or were recently completed in North America including the following:[11]

- Ameren, Missouri (CPP, TOU)
- Anaheim, California (PTR)
- Commonwealth Edison, Illinois (RTP)
- Hydro Ottawa, Ontario (CPP, PTR)
- Idaho Power, Idaho (CPP, TOU)
- Public Service Electric and Gas (PSE&G), New Jersey (CPP)

Currently available results from these pilots are summarized in Appendix E.

- This paper unfolds as follows. In Section I, we describe the PRISM Impacts Model in terms of inputs, rate designs, elasticity estimates, and output. In Section II, we describe the PRISM Benefits Model in terms of inputs and outputs. In Section III, we describe the standard benefit cost models that are used to evaluate demand-side programs in the electric utility industry. In Section IV, we

[11] In addition, pilots are planned for the District of Columbia, Hawaii and Maryland.

discuss the hedging cost (or risk) premium embedded in static rates.[12] In Section V, we describe the benefits of dynamic pricing under alternative market structures—deregulated distribution companies and vertically integrated utilities. In Section VI, we describe alternative methods that are currently used for achieving demand response such as direct load control and time-of-use rates. In Appendices A and B, we discuss the worksheets in the PRISM Impacts Model and the PRISM Benefits Model. In Appendix C, we summarize the California Statewide Pricing Pilot. In Appendix D, we include a presentation that provides an overview of the PRISM model, "Developing Critical Peak Pricing Tariffs with the PRISM Software." In Appendix E, we provide a summary of results from dynamic pricing pilot programs. In Appendix F, we provide an analysis of the impacts of dynamic pricing on low-income customers. In Appendix G, we provide a summary of information technologies that can promote demand response. In Appendix H, we provide a more detailed discussion of the elasticity estimates in PRISM. The appendices are available online on the EEI website. To access these documents, please visit www.eei.org/ami

[12] By definition, a static rate does not respond to fluctuations in wholesale prices. Therefore, a static rate can be viewed as a price combined with an "insurance" premium that insures against wholesale price volatility.

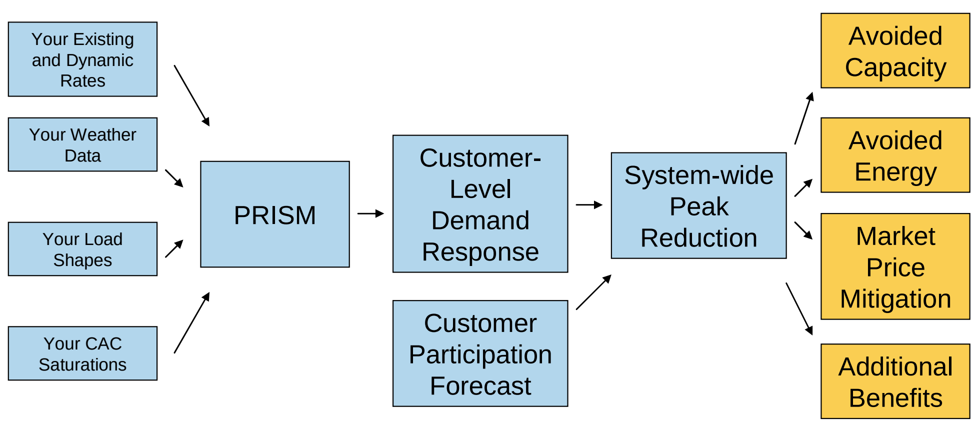
SECTION I: PRISM SUITE IMPACTS MODEL

The purpose of the PRISM Suite Impacts Model is to estimate the change in consumption per customer resulting from dynamic pricing. In addition to estimating the impact for the average residential customer, PRISM estimates impacts for three subsets of residential customers based on the presence of central air conditioning: CAC with no enabling technology (such as a price-sensitive thermostat or direct load control switch), CAC with an enabling technology, and no CAC.

As shown in Figure 3, in addition to the new rate, the PRISM Impacts Model requires information on the following utility-specific variables: customer load shapes (kWh per hour by pricing period), CAC saturation, and weather conditions (measured in cooling degree hours by pricing period).

The purpose of the PRISM model is to estimate the impacts of dynamic pricing. In this section, we introduce five rate designs and use these rate designs to demonstrate how to quantify the economics of dynamic pricing in terms of benefits to the consumer and benefits to the utility.

Figure 3: PRISM Suite: Impacts and Benefits Models



Simulating Impacts of Alternative CPP/TOU Rate Designs

The purpose of the PRISM Impacts Model is to simulate the response of customers to dynamic pricing. That is, it simulates how much customers will shift load in response to alternative rate designs. In this paper, we simulate the impacts of four dynamic rate designs—two CPP/TOU rates that include a critical peak rate, a non-critical peak rate, and an off-peak rate (where CPP High has a critical peak rate of $1.10 and CPP Low has a critical peak rate of $0.70); a pure critical peak pricing (Pure CPP) rate (where the peak rate is equal to the off-peak rate), and a peak-time rebate (PTR). Under the PTR, customers stay on their current flat rate but receive a “rebate” for shifting during critical peak hours. For comparison purposes, we also include a TOU rate (TOU High). At a later stage, other rate designs such as variable peak pricing (VPP) and real-time pricing (RTP) can be introduced into the analysis. However, CPP and PTR are the primary rates under consideration in this paper.[13]

[13] Both Commonwealth Edison and Ameren have a real-time pricing program for residential customers in Illinois.

For illustrative purposes, we assume that these rates are in effect for the summer months (i.e., from June through September or a total of 2,928 hours), the peak period is from 2 p.m. to 7 p.m. on summer weekdays (non-holidays), and the off-peak period is all other hours. We also assume that the two CPP/TOU rates—CPP High and CPP Low—are each in effect for a maximum of 12 days per summer or 60 hours.[14] Therefore, the number of non-critical peak day hours is 360 and the number of off-peak hours is 2,508.

As shown in Table 1, the current rate is assumed to be a flat rate of $0.14 per kWh.[15] The five alternative rates all embody an average rate of $0.14 per kWh and are termed “revenue neutral.” (See Table 1.)[16]

Table 1: Five Alternative Rate Designs

	Existing Rate	TOU High	PTR	Pure CPP	CPP High	CPP Low
CPP Rate	$0.14	$0.34	$1.10	$1.10	$1.10	$0.70
Peak Rate	$0.14	$0.34	$0.14	$0.10	$0.14	$0.19
Off Peak Rate	$0.14	$0.10	$0.14	$0.10	$0.09	$0.10

- For the PTR rate, we assume that customers pay the current rate of $0.14 per kWh for all energy consumed and also receive a “credit” or rebate equal to the difference between the CPP rate and the flat rate ($1.10 minus $0.14 equals $0.96 per kWh) for any energy shifted from critical peak hours to other hours.
- For the Pure CPP rate, we include a pure CPP variant where the peak rate of $1.10 per kWh is in effect from 2 p.m. to 7 p.m. on 12 critical days and the off-peak rate of $0.10 per kWh is in effect for all other hours of the summer; there is no non-CPP peak rate period. This means that for 2,868 of the 2,928 hours of the summer (98 percent of the summer hours), the customer gets a discount of $0.04 per kWh.
- For the CPP High rate, the critical peak rate is equal to $1.10 per kWh, the peak rate is equal to the current rate ($0.14 per kWh), and the off-peak rate is $0.10 per kWh.
- For the CPP Low rate, the critical peak rate is equal to $0.70 per kWh, the peak rate of $0.19 per kWh is higher than the current rate, and the off-peak rate is $0.10 per kWh. It is important to note that the critical peak price is only in effect for 2 percent of the summer hours.
- Finally, for comparison, we include a TOU High rate with a peak price of $0.34 per kWh and an off-peak price of $0.10 per kWh (i.e., a ratio of about 3.5 to 1).

Figure 4 shows the CPP High rate where the peak rate on 12 critical peak days is $1.10 per kWh from 2 p.m. to 7 p.m. (60 hours total) and a peak rate on the remaining 72 non-critical days of $0.14 per kWh (360 hours total); the off-peak rate for the entire summer period including weekends is equal to $0.09 per kWh (2,508 hours total). This is in contrast to the more traditional TOU High rate shown in Figure 5, which has a peak rate of $0.34 per kWh from 2 p.m. to 7 p.m. (420 hours total) and an off-peak rate of $0.10 per kWh (2,508 hours total). However, as shown in Figure 6, it is important to note the small number of hours when the critical peak price is in effect and the large number of hours when the off-peak price (which is lower than the

[14] The number of hours per summer will vary by utility and the PRISM model can be used to vary the hours. However, we believe that 12 days at five hours per day (or 60 total hours over the summer) represents a minimum number of hours and therefore results in a conservative benefits estimate for the dynamic prices.

[15] Or, if the current rate is a tiered rate, the same approach can be used if the rate for the average customer is $0.14 per kWh.

[16] These rates are meant to be illustrative and alternative rate designs can be evaluated in the PRISM software.

current rate) is in effect. In the example in Figure 6, the high price is in effect for 60 hours of the four-month summer (about 2 percent of the 2,928 summer hours) and the off-peak price is in effect for 2,508 hours of the summer (about 86 percent of the summer hours).

Figure 4: CPP/TOU Rate – CPP High: 24-hour Period – Summer Weekday

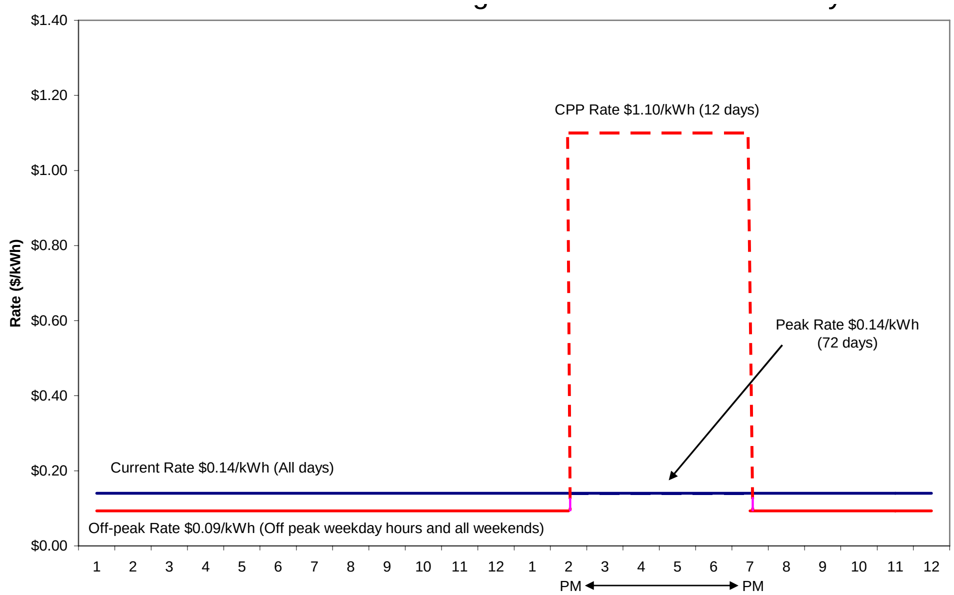


Figure 5: TOU High Rate: 24-hour Period – Summer Weekday

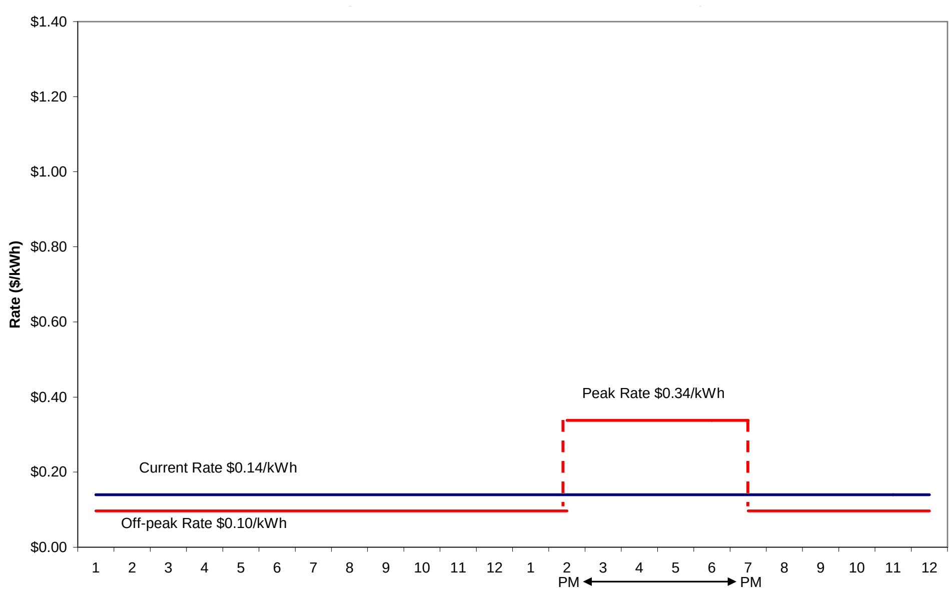
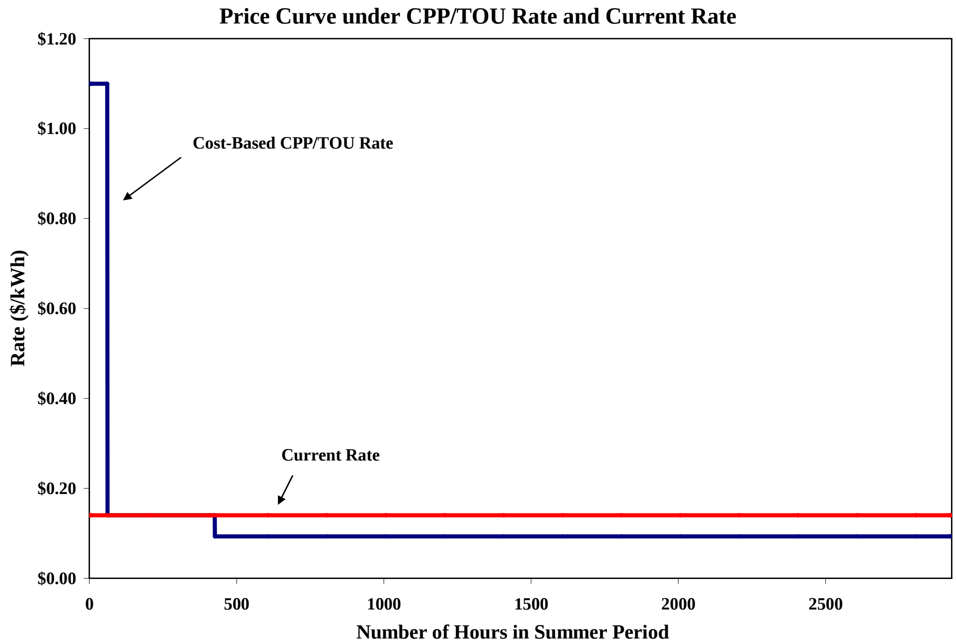


Figure 6: Under the CPP High rate, the high "Critical Peak" price is in effect for 2% of the summer hours whereas the low "Off-Peak" price is in effect for 86% of the hours



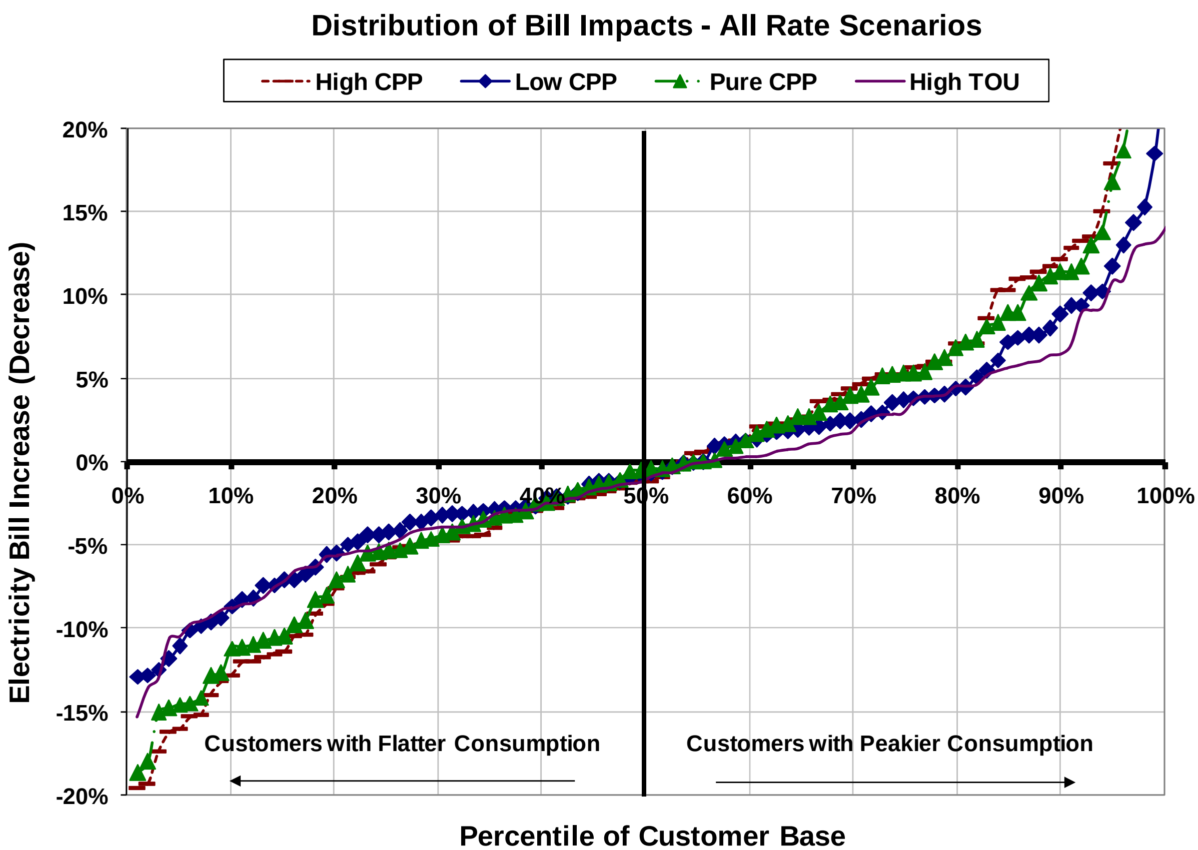
Each of these rates is designed to be revenue neutral (relative to the flat rate of $0.14 per kWh), meaning that if the average customer does not change his or her load shape, their summer monthly bill will remain unchanged. Of course, customers with a flatter-than-average load shape would be immediate winners and those with a peakier-than-average load shape would be immediate losers (in the absence of load curtailment and/or shifting). As shown in Table 2, for the average residential customer, assuming no load shifting under the CPP High rate, the monthly bill under the flat rate is equal to the monthly bill under the Pure CPP rate.

Table 2: Example of Revenue Neutrality for CPP High Rate: Summer Monthly Bill Comparison Based on Average Usage Customer (Peak is 2 p.m. - 7 p.m.)

	Existing Bill			New Bill		
	Summer Usage (kWh)	Old Rate ($/kWh)	Bill ($)	Summer Usage (kWh)	New Rate ($/kWh)	Bill ($)
Critical Peak	40	$0.14	$6	40	$1.10000	$44
Peak	140	$0.14	$20	140	$0.14000	$20
Off peak	820	$0.14	$115	820	$0.09317	$76
Total	1000		**$140.00**	1000		**$140.00**

As noted earlier, although the average customer will see no change in the bill, customers with peakier-than-average load shapes that do not shift load will experience higher bills and customers with flatter-than-average load shapes that do not shift their load will experience lower bills.[17] Figure 7 shows the distribution of bill changes for four of the five rates across a sample of residential customers.[18] Assuming no demand response because the rate is revenue neutral, half of the customer load experiences bill decreases and the other half experiences bill increases. However, as discussed below, we can expect significant demand response and reduced bills. The combination of an individual customer's load shape and the specific rate will determine the overall impact on that customer's bill.

Figure 7: Distribution of Bill Impacts Across Customers for Each Rate: Assuming No Load Shifting



PRISM Elasticity Estimates

Under dynamic rates, a typical (or average usage) customer that shifts load during the peak period can be expected to save on their electricity bill. For a specific customer, this will depend on whether the customer has a peakier load shape than average or a flatter load shape than average. For example, as shown in Table 3, under the CPP High rate, a customer that shifts 20 percent of their load from the critical peak period (from 40 kWh (Table 2) to 32 kWh per month (Table 3)) to the off-peak period, can expect to save about $8 per month (representing about 6 percent savings). A customer that shifts during both the critical peak and non-critical

[17] A peakier-than-average load shape means that the customer uses more electricity than average during the peak hours of the day (e.g., 2 p.m. - 7 p.m.) when the utility is experiencing the highest wholesale prices for power. For example, customers with large CAC loads during these hours will have a peakier load shape than customers with smaller CAC loads or without CAC.

[18] The PTR rate is not shown here because there is no bill distribution impact for PTR unless a load shift occurs because, on PTR, a customer that does not shift load simply is billed at the existing rate.

peak periods can expect to save about $9 per month. Shifting during the peak period on non-critical days adds only a marginal amount of savings. However, these are illustrative examples of load shifting. The question of how much a customer will shift load depends on that customer's demand elasticity. The bill savings can be even higher as utility savings are passed on to consumers from avoiding high cost wholesale market purchases, avoiding expensive peak generation, and/or avoiding (or delaying) construction of expensive new generation.

Table 3: Illustrative Example of Bill Savings Under CPP High Rate: 20% Load Shifting Scenario (Summer Monthly Bill Based on Average Usage Customer)

	Shift 20% off Critical Peak			**Shift 20% off Critical Peak and Peak**		
	Usage (kWh)	Rate ($/kWh)	Bill ($)	Usage (kWh)	Rate ($/kWh)	Bill ($)
Critical Peak	32	$1.10	$35	32	$1.10	$35
Peak	140	$0.14	$20	112	$0.14	$16
Off peak	828	$0.09	$77	856	$0.09	$80
Total	1000		**$132**	1000		**$131**
	Bill Savings:		**$8**	Bill Savings:		**$9**

PRISM utilizes information from the California SPP to calibrate elasticity estimates.[19] The generic SPP model coefficients are combined with utility-specific CAC saturation information and weather data to produce utility-specific elasticity estimates by customer type. These elasticity estimates are the "drivers" behind the customer response to a price increase in PRISM. As shown in Table 4, the PRISM model includes two substitution elasticity estimates (one for CPP days and one for non-CPP days) and two daily price elasticity estimates (one for CPP days and one for non-CPP days). These estimated elasticities vary by customer type—average customer (Average), customers with central air conditioning (CAC), and customers without central air conditioning (No CAC).[20]

Empirical estimates of PTR-specific elasticities are not available at this time, even though two pilots (Anaheim and Hydro Ottawa) have estimated load impacts associated with PTR. A priori, one might expect PTR elasticities to be lower than CPP elasticities, since (under the PTR rate) the customer is rewarded for saving during critical peak hours but is not penalized for using electricity during critical peak hours. This means that if the customer does nothing under PTR, the bill will not change, but if the customer does respond, the bill will be lower. In the absence of empirical evidence on the PTR elasticity, we have made a conservative assumption, i.e., assumed that the price elasticity estimates for the PTR rate are the same as the price elasticities shown in Table 4. But we have also allowed for the fact that in order for customers to respond to a PTR rate, they need to be aware of it. Reviewing the limited information on customer awareness of PTR, we have assumed that customer awareness of the PTR is 50 percent.

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19 Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot." March 16, 2005.

20 Questions have been raised about the persistence of the elasticity estimates. The CA SPP, on which these elasticities are based, included 27 "price notification" days over two summers and one winter. Given the length of this experiment, we believe that the elasticity estimates are likely to remain accurate over time.

Table 4: Calibrated Elasticity Estimates by Customer Type:
Peak to Off-Peak Substitution Elasticity and Daily Price Elasticity

	Average	CAC	No CAC
Substitution Elasticity (Peak to Off Peak) for CPP Days	-0.11762	-0.13853	-0.05489
Daily Price Elasticity for CPP Days	-0.03003	-0.03993	-0.00033
Substitution Elasticity (Peak to Off Peak) for Non-CPP Days	-0.11048	-0.13139	-0.04775
Daily Price Elasticity for Non-CPP Days	-0.04660	-0.05650	-0.01690

- For the CPP days, the substitution elasticity estimate of -0.12 for the average customer on CPP days indicates that a 100 percent increase in the ratio of the critical peak price to the off-peak price will lead to a 12 percent reduction in the corresponding ratio of electricity consumption between the critical peak period to the off-peak period. In other words, if the peak to off-peak price ratio increased from a ratio of 2 to a ratio of 4 (i.e., a 100 percent increase), we would expect a 12 percent shift in electricity consumption from the peak to the off-peak period. The elasticity of substitution is thus a measure of the pure load shape change that is induced by the new rate design. Note that, in contrast, the daily price elasticity of -0.03 for the average customer on CPP days indicates that a 100 percent increase in price will lead to a 3 percent reduction in energy usage on critical days. This represents a pure measure of change in the level of daily electricity consumption.
- For the non-CPP days, the substitution elasticity estimate is -0.11 while the daily price elasticity is -0.05 for the average customer.

The elasticity estimates in Table 4 also indicate that customers with CAC respond more (i.e., have much higher elasticities) to price changes than those without CAC. This is because the most effective way to respond to a high price during the summer months is by cycling or turning off the central air conditioner. In general, customers without CAC have fewer price response options. Although customers with room air conditioners can turn individual units off, the overall response is not as great as with a central unit.

PRISM Impacts Model: Impact Estimates

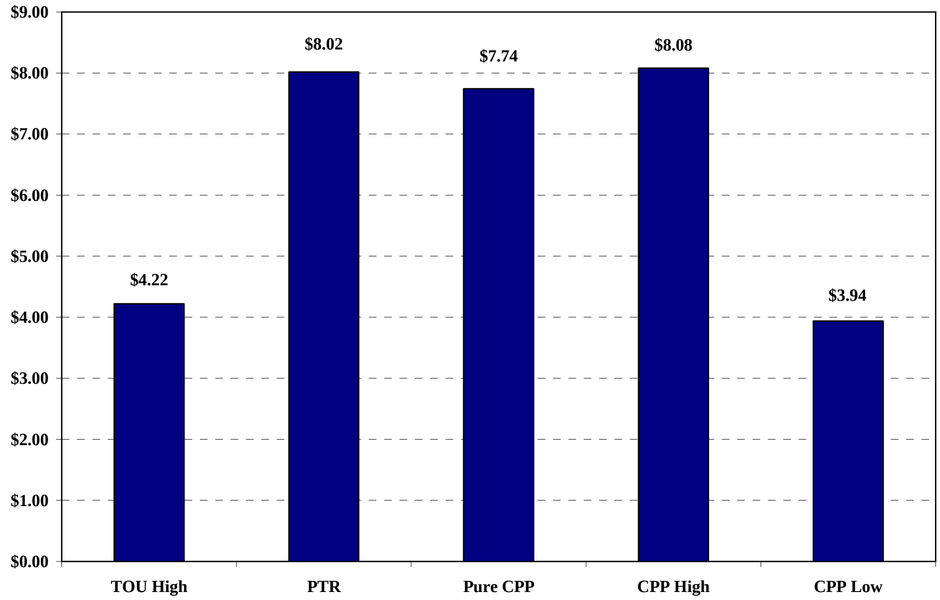
The PRISM Impacts Model provides an estimate of the change in consumption in the peak and off-peak periods by day type (critical day and non-critical day) and the resulting bill savings per customer. Table 5 provides an example of the PRISM impact results (i.e., bill savings and energy savings during peak hours) for the five rate designs by four customer types—average customer, customers without CAC, customers with CAC, and customers with CAC and an enabling technology (CAC + Tech Customer). In this paper, we define an enabling technology as either a central air conditioning switch or a smart thermostat.[21] As a result of shifting energy from peak hours to off-peak hours, customers realize bill savings. Figure 8 provides a comparison of the monthly bill savings for the average customer for each of the five rates.

Table 5: PRISM Results Summary: Average Customer Monthly Bill Savings And Peak Shifting by Rate Scenario

	Existing	TOU High	PTR	Pure CPP	CPP High	CPP Low
CPP Rate	$0.14	$0.34	$1.10	$1.10	$1.10	$0.70
Peak Rate	$0.14	$0.34	$0.14	$0.10	$0.14	$0.19
Off Peak Rate	$0.14	$0.10	$0.14	$0.10	$0.09	$0.10
Monthly Bills						
Average Customer	$140.00	$135.78	$131.98	$132.26	$131.92	$136.06
No CAC Customer	$106.27	$103.10	$102.00	$102.25	$101.83	$103.60
CAC Customer	$151.20	$145.92	$141.62	$141.01	$140.64	$146.03
CAC + Tech Customer	$151.20	$144.29	$138.53	$138.08	$137.58	$144.53
Bill Savings ($/month):						
Average Customer	-	$4.22	$8.02	$7.74	$8.08	$3.94
No CAC Customer	-	$3.17	$4.27	$4.02	$4.44	$2.67
CAC Customer	-	$5.28	$9.58	$10.19	$10.56	$5.17
CAC + Tech Customer	-	$6.91	$12.67	$13.12	$13.62	$6.67
Energy Savings - Critical Days - Peak Hours (kWh/month):						
Average Customer	-	4.30	7.69	8.59	8.78	6.80
No CAC Customer	-	1.37	2.24	2.59	2.67	2.07
CAC Customer	-	5.43	9.77	10.86	11.09	8.62
CAC + Tech Customer	-	7.06	12.70	14.12	14.42	11.21
Energy Savings - Non Critical Days - Peak Hours (kWh/month):						
Average Customer	-	14.74	0.00	-2.21	2.86	5.88
No CAC Customer	-	4.58	0.00	-0.56	0.97	1.85
CAC Customer	-	19.02	0.00	-2.94	3.66	7.60
CAC + Tech Customer	-	24.72	0.00	-3.82	4.76	9.88

[21] With a central air conditioning switch, the utility issues a radio signal informing the switch that a load reduction period is occurring. The switch responds by either turning off or cycling the air conditioning compressor for a specific period of time each hour during the event (such switches are also used in load control programs). With a smart thermostat, the utility issues a radio signal informing the thermostat that a load reduction event is occurring and the thermostat responds with a pre-programmed change in the thermostat setting (typically 2 to 4 degrees).

Figure 8: Average Customer Monthly Bill Savings by Rate Type



These results provide several insights into dynamic rate design.

- Comparing the CPP High and the CPP Low rates shows that the CPP High rate provides a greater incentive to shift load during peak hours on critical days and, as a result, the average bill savings is higher—about $8 per month under CPP High compared to $4 per month under CPP Low.[22] For CAC customers, the savings are much higher under CPP High—about $13 per month (a bill savings of 9 percent)—than under either the CPP Low rate or the TOU High rate, which are both below $7 per month. (See Table 5.)
- Comparing the CPP High rate to the PTR, the PTR results in slightly less load shifting on critical days and no load shifting on non-critical days. But this is a per-customer result, and the primary issue with the PTR rate is how many customers will actually be aware of this rate since customers do not necessarily "join" a PTR program, per se.
- Comparing the CPP High and Pure CPP rates shows that the Pure CPP rate produces results similar to the CPP High rate in terms of customer bill savings and energy savings during peak hours on critical peak days. However, on non-critical peak days, the Pure CPP rate results in more energy usage during peak hours because the peak price is lower than the CPP High peak price. (See Table 5.)
- The TOU High rate does shift load during peak hours but, on critical days (when prices are highest), it is only about half as effective as the CPP rates. This is because, under a TOU rate, there is no additional incentive to modify behavior on critical days (compared to non-critical days).

It is well known that a static or flat rate includes a hedging or risk premium because customers pay the same amount regardless of the cost impact on the supplying utility. This is because the utility is responsible for generating, purchasing power, or purchasing a hedge against market volatility (at whatever the cost), and all

22 Based on the average bill of $140 per month, $8 represents 6 percent and $4 represents 3 percent bill savings. For CAC customers, the average bill is $151 per month. For non-CAC customers, the average bill is $106 per month.

of these costs are eventually passed through to customers. The purpose of dynamic pricing is to provide customers with more accurate price signals (i.e., prices that are linked to the wholesale market), thereby helping the utility avoid costly generation, wholesale market purchases, and/or hedges. This has important implications for rate design and is discussed in more detail in Section IV.

For some customers, shifting energy from peak to off-peak periods will result in some inconvenience. We do not know the exact price of that inconvenience. However, we do know that when a customer shifts energy in response to a price signal, the dollar value of the bill savings either exactly compensates or more than compensates the customer for the inconvenience associated with shifting. In other words, by actually shifting usage the customer has revealed that his/her price of inconvenience is less than the bills savings.[23]
In summary, the PRISM Impacts Model estimates the change in consumption during peak and off-peak periods by customer type. This change in consumption results in bill savings, which are the customer-specific benefit. When a dynamic pricing program is voluntary, we can be certain that the bill savings resulting from the program are sufficient to offset any costs that the customer may incur.[24] The benefits to the utility resulting from customer load shifting—primarily the avoided capacity and fuel costs—are quantified in the PRISM Benefits Model (Figures 2 and 3) and are discussed in the next section.

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[23] Although dynamic pricing programs result primarily in energy shifting, not energy saving, this same argument can be made for energy savings. If a customer gives up "using the dryer," for example, to save energy, then the bill savings that customer receives from not using the dryer is greater than the cost of the inconvenience.

[24] We do not know the exact costs to the customer but we do know that the benefits exceed the cost. Otherwise the customer would not voluntarily join the program.

SECTION II: PRISM SUITE BENEFITS MODEL

The purpose of the PRISM Suite Benefits Model is to estimate utility cost savings from dynamic pricing—capacity cost savings, energy cost savings, transmission cost savings, and distribution cost savings.[25] When a utility realizes cost savings, the cost to serve a customer decreases. Hence, utility cost savings are ultimately passed on to the customer in the form of lower rates. For this paper, we assumed that the value of avoided capacity cost was about $70 per kW-year (or $188 per MW-day), the value of avoided energy costs ranged from $0.06 per kWh to $0.30 per kWh depending on the specific day and hour, the value of avoided transmission cost was about $15 per kW-year, and the value of avoided distribution cost was about $12 per kWh-year.[26] In addition to estimating the impact for the average residential customer, the model also estimates the total impact based on the forecast of customer participation in the dynamic pricing program.

As shown earlier in Figure 2, in addition to the per-customer impacts estimated from the PRISM Impacts Model, the PRISM Benefits Model requires a forecast of the net number of customers on the dynamic rate each year (by customer type if possible). In addition, in order to estimate overall utility avoided costs (or cost savings), forecasts of capacity costs, wholesale energy costs, and transmission and distribution infrastructure replacement costs are required.

An important consideration in developing the market penetration forecast is whether the dynamic pricing program is an “opt-in” or “opt-out” program. Under an opt-in scenario, customers have to sign up or join the dynamic pricing program. Under an opt-out scenario, the dynamic pricing rate is the default rate and customers have the option to opt out. The total benefits to the utility will vary significantly depending on how the dynamic pricing program is deployed and the number of customers that participate. For this paper, we assume that 20 percent of the customers join the program under an opt-in scenario and that 80 percent join the program under an opt-out scenario. **However, these opt-in and opt-out percentages are assumptions and illustrative. Whether 20 percent or 80 percent of customers join a specific dynamic pricing program, for example, will be highly dependent on the program design, the rates, and the success of the marketing and implementation strategy.**

Utility Benefits per Customer

The PRISM Benefits Model provides estimates of the utility savings (i.e., benefits) associated with dynamic pricing. Table 6 provides an estimate of the net present value (NPV) of the utility cost savings associated with the CPP High rate for the average customer over 15 years.[27] On average, over 15 years, the NPV associated with the CPP High rate is about $829 per customer.

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25 For many utilities, these cost savings are not realized instantaneously due to regulation and other factors. This issue is discussed in more detail in Section V.

26 Capacity and energy costs are based on PJM east prices. Transmission and distribution costs are estimates.

27 Environmental benefits are not included because dynamic pricing results in efficiency gains but is not likely to result in environmental benefits unless base load generation is nuclear. Such benefits are very specific to the individual utility’s operations.

Table 6: NPV of Utility Cost Savings Under the CPP High Rate per Customer (Over 15 Years)

(2007 Dollars)	Utility Capacity Cost Savings	Utility Energy Cost Savings	Transmission System Cost Savings	Utility Distribution Cost Savings	Total Savings
2009	49.30	4.77	10.29	8.23	72.59
2010	47.71	4.49	9.67	7.74	69.61
2011	46.17	4.22	9.09	7.27	66.76
2012	44.69	3.97	8.55	6.84	64.03
2013	43.24	3.73	8.03	6.43	61.43
2014	41.85	3.51	7.55	6.04	58.95
2015	40.50	3.30	7.10	5.68	56.57
2016	39.19	3.10	6.67	5.34	54.30
2017	37.93	2.91	6.27	5.02	52.14
2018	36.70	2.74	5.90	4.72	50.06
2019	35.52	2.57	5.55	4.44	48.08
2020	34.37	2.42	5.21	4.17	46.18
2021	33.27	2.27	4.90	3.92	44.36
2022	32.19	2.14	4.61	3.69	42.62
2023	31.15	2.01	4.33	3.46	40.96
Net Present Value	**593.80**	**48.14**	**103.72**	**82.98**	**828.65**

Table 7 provides a comparison of the different components of the utility cost savings for each rate design for the average customer over 15 years. These results show the following:

- The utility cost savings for the CPP High rate and the Pure CPP rate are very similar ($829 versus $807). These two rates have the highest critical peak prices and result in the greatest savings for the utility (and ultimately for the customer).
- The utility cost savings associated with the TOU High rate ($422) is about half as large as the CPP High rate or the Pure CPP rate.
- The utility capacity cost savings dominate the overall utility savings under all rates.

Table 7: NPV of Utility Cost Savings per Customer (Over 15 Years)

(2007 Dollars)	Utility Capacity Cost Savings	Utility Energy Cost Savings	Utility Transmission Cost Savings	Utility Distribution Cost Savings	Total Savings
TOU High Rate	$290	$40	$51	$41	$422
PTR Rate	$520	$73	$91	$73	$756
Pure CPP Rate	$581	$44	$101	$81	$807
CPP High Rate	$594	$48	$104	$83	$829
CPP Low Rate	$460	$46	$80	$64	$651

Total Utility Benefits Under Opt-out vs. Opt-in

Table 8 provides an estimate of the total benefit to the utility of each rate design under an opt-out scenario assuming 80 percent participation. This is the product of the per-customer impact in Table 7 and the customer participation forecast (assuming that over time about 80 percent of the residential customers join the program). Under the PTR program, customers do not join a program, per se (because they simply receive a rebate if they shift their usage relative to a baseline). Therefore, the issue for the PTR program is how many customers are actually aware of the rate. For computing benefits for the PTR rate, we use the same elasticity as the CPP rate and assume that 50 percent of all customers are aware of the PTR program. As shown in Table 8, the savings associated with the prices examined under an opt-out deployment range from about $298 million under the TOU High rate to $586 million under the CPP High rate (almost double the TOU rate savings).

Table 8: NPV of Total Utility Cost Savings Over 15 Years Under "Opt-out" Scenario (80% Participation)*

(2007 Dollars)	Utility Capacity Cost Savings	Utility Energy Cost Savings	Utility Transmission Cost Savings	Utility Distribution Cost Savings	Total Savings
TOU High Rate	$207,883,104	$27,392,650	$34,707,559	$27,766,047	$297,749,361
PTR Rate	$232,523,940	$31,090,361	$38,821,522	$31,057,217	$333,493,040
Pure CPP Rate	$415,864,528	$29,772,277	$69,431,534	$55,545,227	$570,613,566
CPP High Rate	$425,080,714	$32,942,093	$70,970,241	$56,776,193	$585,769,241
CPP Low Rate	$329,268,012	$31,474,419	$54,973,631	$43,978,905	$459,694,967

**The opt-out percentage is not relevant for the PTR rate, which assumes that all customers are eligible for the "credit" but only 50% are aware of the PTR.*

Capacity cost savings represent about two-thirds of the total savings under each rate design. As shown in Figure 9, for the CPP High rate, the capacity cost savings represent over 70 percent of the total savings to the utility.

It is also important to note that the vast majority of the total energy decrease in the peak period—about 90 percent—(and therefore the associated utility savings) occurs during the 60 critical peak hours of the four summer months. The other 10 percent of the energy decrease is spread among the 365 remaining (non-critical day) peak hours of the summer. The CPP rate is very effective in that 90 percent of the energy usage decrease occurs in these 60 critical hours. Therefore, targeting a small number of very high-cost hours (as the CPP rate does) and creating an incentive for customers to respond is highly effective from both a customer benefits and a utility benefits perspective. It is also far simpler for a customer to focus on 12 days of the summer (for five hours each day) rather than every single weekday (as would occur under a typical TOU rate).

Figure 9: Utility Benefits Under CPP High Rate: Capacity Cost Savings Dominate The Benefits to the Utility

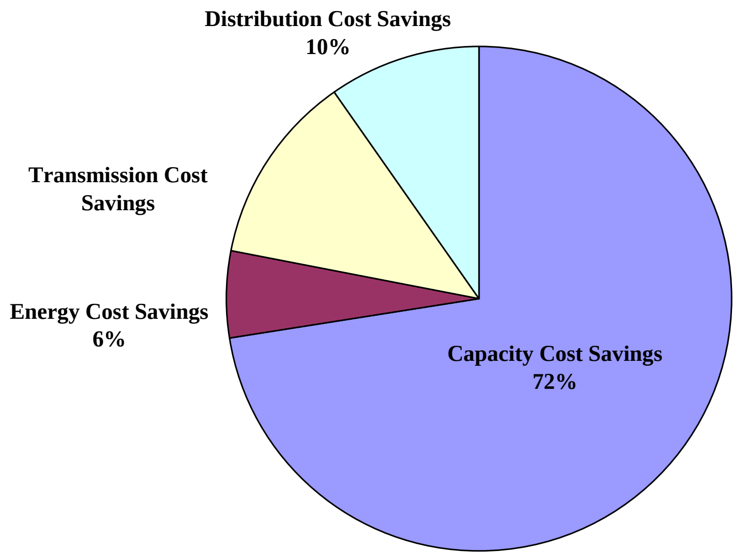

Table 9 provides an estimate of the total benefit to the utility of each rate design under an opt-in scenario assuming 20 percent participation. This is the product of the per-customer impact in Table 7 and the customer participation forecast (assuming that over time about 20 percent of the residential customers join the program). As shown in Table 9, the savings associated with the prices examined in this paper under an opt-in deployment range from about $74 million (under the TOU High rate) to about $146 million (under the CPP High rate). Note that the savings for the PTR rate remain at $334 million because the opt-in percentage is not relevant to this rate as explained earlier. Comparing these savings estimates to those in Table 8 shows a significant decrease in total benefits to the utility for all rates except the PTR (which remains the same where deployment is opt-in or opt-out). Hence, the specific deployment strategy (i.e., opt-in vs. opt-out) for the dynamic pricing option has a major impact on the overall benefits to the utility.

Table 9: NPV of Total Utility Cost Savings Over 15 Years Under "Opt-in" Scenario (20% Participation)*

(2007 Dollars)	Utility Capacity Cost Savings	Utility Energy Cost Savings	Utility Transmission Cost Savings	Utility Distribution Cost Savings	Total Savings
TOU High Rate	$51,970,776	$6,848,163	$8,676,890	$6,941,512	$74,437,340
PTR Rate	$232,523,940	$31,090,361	$38,821,522	$31,057,217	$333,493,040
Pure CPP Rate	$103,966,132	$7,443,069	$17,357,883	$13,886,307	$142,653,391
CPP High Rate	$106,270,178	$8,235,523	$17,742,560	$14,194,048	$146,442,310
CPP Low Rate	$82,317,003	$7,868,605	$13,743,408	$10,994,726	$114,923,742

**The opt-out percentage is not relevant for the PTR rate, which assumes that all customers are eligible for the "credit" but only 50% are aware of the PTR.*

Comparing Tables 8 and 9, excluding PTR, the benefits to the utility for the CPP High rate under an opt-in deployment will be lower than the benefits for a plain vanilla TOU High rate under an opt-out deployment. This means that, in order to realize the potential benefits of dynamic pricing, customer participation in the program is critical. Under the opt-in scenario, the benefits under the PTR dominate all of the other rates because customers don't have to actually decide to participate; they are automatically eligible for the rate. Customer participation in dynamic pricing programs is typically estimated based on pilot results—either a utility's own pilot or a similar program run by another utility. Two of the California utilities, San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE), are rolling out PTR rates rather than CPP rates in an effort to get customers accustomed to responding to dynamic rates and to raise awareness of dynamic rates. Other utilities are considering a PTR rate in the short term as a transition to a CPP rate.

Effect of CPP Rate Design on Total Utility and Customer Benefits

It is important to understand that the actual design of the CPP rate will have a major effect on the benefits realized. Many utilities are concerned that setting the critical peak price too high will scare customers away from the program. Our experience suggests the opposite! Customers are more interested in programs if they can realize a significant bill savings, or about a 10 percent monthly savings. Customers are supportive of high critical peak prices and realize that they can save money by shifting energy to the lower (than existing rate) off-peak prices. In order to realize such a monthly bill savings from CPP, the rate should be designed so that the critical peak price is greater than $1.00 per kWh. Table 10 shows the per-customer monthly benefits as well as the total utility benefits over 15 years (in present value terms) of five different CPP rates, assuming 20 percent of customers opt in where the critical peak price ranges from a high of $1.75 per kWh to a low of $0.80 per kWh.[28] Based on the average monthly bill savings, the low critical peak price of $0.80 per kWh results in bill savings of less than $5 a month for the average customer (about 3.6 percent for an average monthly bill of $140) whereas the high critical peak price of $1.75 results in monthly bill savings of about $19 per month for the average customer (or about 13.6 percent).[29]

As shown by comparing the utility cost savings across the different rates, the actual dollar value of the critical peak price is a crucial factor in determining utility cost savings. The CPP rate of $1.75 per kWh results in an overall savings of $206 million, whereas the CPP rate of $0.80 per kWh results in an overall savings of only $133 million (assuming 20 percent participation). A second but much less important consideration is setting the peak price. As shown in Table 10, for a given critical peak price of $1.30, whether the peak price is $0.10 per kWh, $0.14 per kWh, or $0.20 per kWh, the overall impact on utility cost savings is relatively minor (i.e., cost savings range from $171 million to $190 million excluding price mitigation). In our opinion, it makes sense to set a very high critical peak price and then to set the peak price equal to or very close to the current rate.

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[28] Ultimately utility benefits are passed through to customers just as utility costs are passed through to customers. However, in this paper, we use the terminology "customer benefits" only in relation to the short-term bill savings benefits.

[29] These results are based on the PRISM model using the elasticity estimates from the CA SPP. However, the higher critical peak price to off-peak price ratios in Table 10 exceed those used in the SPP and the issue is whether the CA elasticity results hold over a wider range of prices. Fortunately, the recent PSE&G pricing pilot in NJ, which tested a much higher price ratio than in CA, results in a critical peak usage shift that is consistent with the PRISM model results. This is discussed in more detail in Appendix E.

Table 10: How CPP Rate Design Affects Total Utility and Customer Benefits

Customer Bill Impact ($/Month)

Rate Setup			Average	CAC	No CAC	CAC + Tech
CPP - $1.75	Peak - $.14	Off Peak - $.06	-18.73	-24.05	-9.22	-31.09
CPP - $1.30	Peak - $.20	Off Peak - $.06	-14.51	-18.60	-7.76	-24.09
CPP - $1.30	Peak - $.14	Off Peak - $.08	-10.95	-14.21	-5.76	-18.35
CPP - $1.30	Peak - $.10	Off Peak - $.09	-10.41	-13.59	-5.28	-17.52
CPP - $.80	Peak - $.14	Off Peak - $.11	-4.43	-5.86	-2.67	-7.55

Total Present Value of New Rate, Excluding Price Mitigation ($ Millions)

Rate Setup			Total Market	CAC	No CAC	CAC + Tech
CPP - $1.75	Peak - $.14	Off Peak - $.06	205.9	133.6	14.4	57.9
CPP - $1.30	Peak - $.20	Off Peak - $.06	189.7	123.1	13.3	53.3
CPP - $1.30	Peak - $.14	Off Peak - $.08	175.5	114.0	12.1	49.4
CPP - $1.30	Peak - $.10	Off Peak - $.09	171.0	111.1	11.7	48.2
CPP - $.80	Peak - $.14	Off Peak - $.11	132.9	86.5	9.0	37.5

SECTION III: STANDARD BENEFIT-COST TESTS FOR EVALUATING COST-EFFECTIVENESS

In this section, we define the general components of the five standard benefit-cost tests used to evaluate demand-side program cost effectiveness. Such tests are used for both energy efficiency programs and dynamic pricing programs. For each test, we identify the source of data as either the utility or the PRISM model. In general, the cost components for the tests are utility-specific and the benefit components for each of the tests can be obtained from the PRISM Suite. Before we begin our discussion of the purpose of each test, Table 11 summarizes the components of the five benefit-cost tests from the California Standard Practice Manual.[30]

In practice, most utilities use the total resource cost (TRC) test today as the basic test. A few utilities still use the rate impact (RIM) test. The TRC provides a measure of net expenditures from the point of view of the utility and its ratepayers taken as a whole. In contrast, the RIM test measures whether rates will have to change as a result of a program. In addition to these standard benefit-cost components, the following should also be considered when evaluating programs: environmental emissions costs and benefits, cost of utility performance incentives (which will be a cost in all tests except the participant test), reliability benefits, and consumer surplus.

Table 11: The Benefit-cost Tests from the California Standard Practice Manual

Test	Benefits	Costs
Participant Test	Participant bill reductions Incentive payments to participants Tax credits	Participant bill increases Program costs paid by participant Fees paid to utility by participant
Total Resource Cost (TRC) Test	Utility avoided energy costs Utility avoided capacity costs Utility avoided distribution costs Utility avoided transmission costs Tax credits	Energy, capacity, and t & d costs Utility rate-based investment Program costs paid by utility (operating, marketing) Program costs paid by participant (investment, operating)
Ratepayer Impact (RIM) Test	Utility avoided energy costs Utility avoided capacity costs Utility avoided distribution costs Utility avoided transmission costs Revenue gains Fees paid to utility by participant	Energy, capacity, and t & d costs Utility rate-based investment Program costs paid by utility (operating, marketing) Revenue losses Incentives paid to participants
Utility Cost Test	Utility avoided energy costs Utility avoided capacity costs Utility avoided distribution costs Utility avoided transmission costs Fees paid to utility by participant	Energy, capacity, and t & d costs Utility rate-based investment Program costs paid by utility (operating, marketing) Incentives paid to participants
Societal Cost Test	Utility avoided energy costs Utility avoided capacity costs Utility avoided distribution costs Utility avoided transmission costs External benefits	Energy, capacity, and t & d costs Utility rate-based investment Program costs paid by utility (operating, marketing) Program costs paid by participant (investment, operating) External costs

30 California Standard Practice Manual: Economic Analysis of Demand-Response Programs and Projects. July 2002. Barakat and Chamberlin, "Principles and Practice of Demand-Side Management," EPRI TR-102556, Final Report, August 1993.

Participant Perspective

The participant test asks the question, “Are participants better off?” This test simply quantifies the net benefits to a participating customer; it does not consider utility impacts. To answer this question, the NPV of the benefits minus the costs shown in Table 12 over the life of the program is calculated. Programs with a positive NPV pass the participant test, implying that participants are better off as a result of the program.

Table 12: Participant Test

PARTICIPANT TEST - Are Participants Better Off?		SOURCE
Benefit	**Participant bill reductions**	PRISM
Benefit	**Incentive payments to participants**	PRISM
Benefit	**Tax credits**	Utility
Cost	**Participant bill increases**	PRISM
Cost	**Program costs paid by participant**	Utility
Cost	**Fees paid to utility by participants**	Utility

Total Resource Cost Perspective

The total resource cost test asks the question, “Does the total resource cost go down?” To answer this question, the NPV of the benefits minus the costs shown in Table 13 over the life of the program is calculated. Costs include supply costs, utility costs, and participant costs. Dollar amounts that flow between the utility and participants drop out. This test measures the change in the average cost of energy across all customers. Programs with a positive NPV pass the total resource cost test. The TRC is similar to the societal test, but differs primarily in that it excludes externalities.

Table 13: Total Resource Cost Test

TOTAL RESOURCE COST (TRC) TEST - Are Resources Conserved?		SOURCE
Benefit	**Utility avoided energy cost savings**	PRISM
Benefit	**Utility avoided transmission cost savings**	PRISM
Benefit	**Utility avoided distribution cost savings**	PRISM
Benefit	**Utility avoided capacity cost savings**	PRISM
Benefit	**Tax credits**	Utility
Cost	**Energy, capacity, and t & d costs**	PRISM
Cost	**Utility rate-based investment**	Utility
Cost	**Program costs paid by utility (operating, marketing)**	Utility
Cost	**Program costs paid by participant (investment, operating)**	Utility

Non-participant (or Rate Impact) Perspective

The rate impact test asks the question, "Are non-participants better off?" The RIM test looks at the change in revenues paid to the utility and the total costs resulting from a program and measures whether rates will have to change. The NPV of the benefits minus the costs shown in Table 14 over the life of the program is calculated. Programs with a positive NPV pass the non-participant test. The RIM test and the participant test when "summed" together result in the TRC test.

Table 14: Rate Impact Test

RATE IMPACT (RIM) TEST - Will Rates Increase?		SOURCE
Benefit	**Utility avoided energy cost savings**	PRISM
Benefit	**Utility avoided transmission cost savings**	PRISM
Benefit	**Utility avoided distribution cost savings**	PRISM
Benefit	**Utility avoided capacity cost savings**	PRISM
Benefit	**Revenue gains**	Utility
Benefit	**Fees paid to utility by participants**	Utility
Cost	**Energy, capacity, and t & d costs**	PRISM
Cost	**Utility rate-based investment**	Utility
Cost	**Program costs paid by utility (operating, marketing)**	Utility
Cost	**Revenue losses**	Utility
Cost	**Incentive payments to participants**	Utility

Utility Perspective

The utility cost test evaluates a program from the utility perspective and asks the question, “Will revenue requirements be lowered as a result of the program?” To answer this question, the NPV of the benefits minus the costs shown in Table 15 over the life of the program is calculated. Table 15 lists the source for each input in the test—either the utility (for the cost components) or PRISM (for the benefit components). Programs with a positive NPV pass the utility cost test.

Table 15: Utility Cost Test

UTILITY COST TEST - Are Revenue Requirements Lowered?		SOURCE
Benefit	**Utility avoided energy cost savings**	PRISM
Benefit	**Utility avoided transmission cost savings**	PRISM
Benefit	**Utility avoided distribution cost savings**	PRISM
Benefit	**Utility avoided capacity cost savings**	PRISM
Benefit	**Fees paid to utility by participants**	Utility
Cost	**Energy, capacity, and t & d costs**	PRISM
Cost	**Utility rate-based investment**	Utility
Cost	**Program costs paid by utility (operating, marketing)**	Utility
Cost	**Incentive payments to participants**	Utility

Societal Cost Perspective

The societal cost test asks the question, “Do societal costs go down?” As noted previously, the only difference between this and the TRC test is the addition of externality costs and benefits. To answer this question, the NPV of the benefits minus the costs shown in Table 16 over the life of the program is calculated. Programs with a positive NPV pass the societal test.

Table 16: Societal Cost Test

	SOCIETAL TEST - Is Society Better Off?	SOURCE
Benefit	**Utility avoided energy cost savings**	PRISM
Benefit	**Utility avoided transmission cost savings**	PRISM
Benefit	**Utility avoided distribution cost savings**	PRISM
Benefit	**Utility avoided capacity cost savings**	PRISM
Benefit	**External benefits**	Utility
Cost	**Energy, capacity, and t & d costs**	PRISM
Cost	**Utility rate-based investment**	Utility
Cost	**Program costs paid by utility (operating, marketing)**	Utility
Cost	**Program costs paid by participant (investment, operating)**	Utility
Cost	**External costs**	Utility

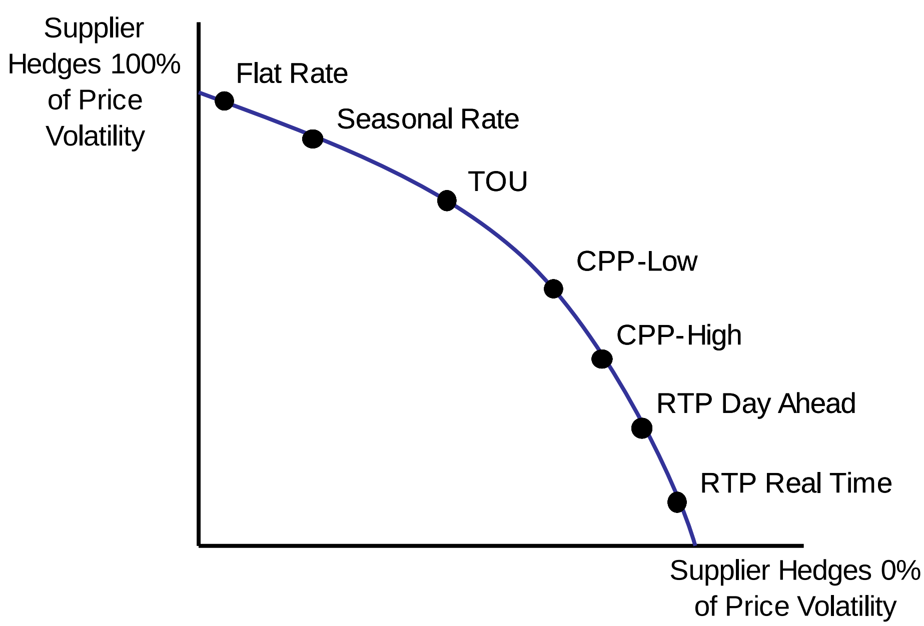
In general, although these tests measure different perspectives, the biggest debate has been between the use of the RIM test (which ensures that all ratepayers benefit) and the TRC test (which looks at the average customer).

SECTION IV: HEDGING COST PREMIUM

Static rates that do not vary dynamically with changing wholesale prices shield customers from price volatility and, more importantly, increase the total cost of meeting demand by requiring utilities to generate or purchase power even when electricity is at its highest cost. These costs are ultimately passed on to consumers. Static rates include flat rates, inverted block rates and traditional TOU rates under which prices vary between peak and off-peak periods in a predictable, static, and therefore non-dynamic fashion. While the vast majority of mass market customers are on static rates, they do not realize they are, in fact, purchasing a premium-priced rate product that is more expensive to provide than a dynamic rate.

From a rate design perspective, a static (or flat) rate is economically inefficient because it shields customers from wholesale market price volatility. As we move from traditional flat rates to more flexible rate options such as TOU, CPP, and RTP, wholesale price signals are passed on to customers and these customers are given the option to respond by shifting demand. Figure 10 shows a range of flexible rate options and the varying wholesale price signals. Providing the wholesale price signal to the customer under more dynamic pricing options is exactly what induces customers to respond to a dynamic price by changing their behavior and shifting their energy usage. Hence, a customer on a real-time price has a much greater incentive to shift load during high-price hours than a customer on a flat rate that would likely not even be aware of the high-price hour. Flexible or dynamic rates promote economic efficiency in the consumption of electricity by providing a direct link between wholesale prices and retail rates.[31]

Figure 10: Flexible Rate Options Transfer Price Volatility Signals from Supplier to Consumer And Provide an Incentive for Demand Response



[31] See A. Faruqui, R. Hledik, and B. Neenan, "Rethinking Rate Design: A Survey of Leading Issues Facing California's Utilities and Regulators." Draft paper prepared for the Demand Response Research Center, Lawrence Berkeley National Laboratory, Berkeley, California. August 2007.

Of the rates shown in Figure 10, each one carries a different hedging premium depending on how much the utility pays to minimize price volatility. Since only customers can change their demand, utilities purchase hedging contracts or make other arrangements to limit their exposure to wholesale price swings. This premium is inversely related to customer exposure to wholesale market prices. The premium is highest when customers see flat rates and the utility suppresses all price volatility to customers (by maximizing its hedging obligations). As rates become more dynamic, the premium decreases and, under a "real time" RTP, it is equal to zero.

Under a flat rate, the supplier or utility will generally purchase a hedging contract to limit its exposure to wholesale market swings, a cost that is generally borne by consumers, and must generate or contract for sufficient power to meet the highest peak hour of the year regardless of the cost of producing or contracting for the power. Under a flat rate, utilities assume that customers cannot be price responsive and are therefore willing to pay a very high price for power a few hours a year. In reality, research over 30 years has shown that industrial, commercial, and residential customers are price responsive and will accept flexible rate options. Under a CPP or RTP rate, customers address the high price signal by shifting their load from high-cost to low-cost times of the day or by decreasing their load overall.

- An hourly RTP rate represents a direct mapping between wholesale hourly prices and the resulting retail rates. For this rate, the risk or hedging premium is zero.
- Alternatively, a day-ahead RTP rate also links wholesale hour prices to retail rates but, since it is a day-ahead mapping, there is still some risk premium in the equation. A study by the Independent System Operator in New England (ISO-NE) estimated the risk premium for this rate to be about 3-5 percent.[32]
- A CPP rate is also linked to wholesale market prices. In particular, it is designed to provide an incentive to customers to respond primarily to the 1-2 percent of the highest-priced hours of the year. While the actual rate is decided in advance and not in real time, the timing of when the rate is in effect is determined on a day-ahead basis based on wholesale market prices. Although the risk premium for this rate has not been estimated empirically, the range will be somewhere between the day-ahead RTP and the TOU rate (i.e., between 5 percent and 8 percent).
- A TOU rate provides an incentive for customers to shift load during peak hours. Similar to the CPP rate, the actual rate is decided in advance and not in real time. However, unlike the CPP rate, the timing of when the rate will be in effect is not linked to either day-ahead or real-time wholesale market prices. Hence, the risk premium embedded in a TOU rate is higher than the CPP rate but lower than the flat rate. ISO-NE estimated the risk premium for a TOU rate to be about 8 percent.[33]
- Finally, a flat rate is simply a price that is averaged across all hours of the year (or, in some cases, a summer flat rate and a winter flat rate may be in effect). Such a rate provides virtually no incentive to customers to shift their load during hours when prices are high in the wholesale market. Therefore, the "hedging cost premium" embedded in a flat rate is the highest of all the rates examined. The same ISO-NE study estimated the risk premium for a flat rate to be about 15 percent. An alternative study estimated the risk premium for a flat rate to be about 11 percent.[34]

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32 Neenan Associates, "Improving Linkages Between Wholesale and Retail Markets Through Dynamic Retail Pricing." Prepared for ISO New England, Inc. December 5, 2005.

33 Ibid.

34 See discussion of subsidies embodied in non-time varying rates in A. Faruqui, R. Hledik, and B. Neenan, "Rethinking Rate Design: A Survey of Leading Issues Facing California's Utilities and Regulators." August 2007. The exact risk premium will vary by location and over time.

Based on this discussion, although we can argue about the exact percentage and how to specifically identify and isolate the hedging premium, it is clear that flat rates include an automatic built-in "premium" or an insurance policy for customers so that wholesale price volatility is avoided.[35] On the other extreme, under an RTP rate, since customers face wholesale prices, the value of the insurance or hedging premium is zero.

As discussed earlier, under a typical revenue neutral dynamic rate (where revenue neutrality is tied to the flat rate, not to the cost to serve), assuming no load shifting, the average customer will see no change in the bill.[36] However, on an individual basis, some customers will see higher bills and some customers will see lower bills, because their bills will be more closely tied to the actual cost of supplying electricity. This will depend on: the dynamic rate option, the "peakiness" of the particular customer's load shape relative to the average customer, and whether the customer responds to the dynamic rate. It is important to note that a customer who is paying a higher bill on a dynamic rate can lower their bill by shifting usage. If all customers were on dynamic rates and shifted their usage, the overall cost to serve customers would decline. This is discussed more in the next subsection.

Load Shifting and Bill Impacts Under Alternative Rates

First, we examine how the load shape alone will influence the electricity bill under each rate option. Basically, a customer with a peakier-than-average load shape on a dynamic rate can expect a bill increase and a customer with a flatter-than-average load shape on a dynamic rate can expect bill savings. Figure 11 shows the distribution of bill impacts resulting from alternative rates.

Now we examine what happens when customers respond to a dynamic price by shifting their load. Figure 12 shows what happens to customer bills when customers shift load in response to a CPP rate. Under this scenario, as a result of load shifting, the percentage of customers experiencing a bill savings increases to about 80 percent of all customers. This means that 20 percent of all customers still experience a bill increase under this CPP rate.

[35] Another way to say this is that a flat rate includes the price of an option to ensure against price fluctuation. The price of the "option" or premium can vary significantly from utility to utility.

[36] The underlying assumption behind a revenue neutral dynamic rate whose revenue neutrality is tied to a flat rate is that the cost to serve a customer on a flat rate is the same as the cost to serve a customer on a dynamic rate. However, these customers actually represent two distinct risk pools and the cost to serve the pool of customers on a dynamic rate is actually lower than the cost to serve the pool of customers on a flat rate. This difference in cost to serve is related to the hedging cost premium and discussed more thoroughly later in this chapter.

Figure 11: Distribution of Bill Impacts Under Alternative Rates and No Load Shifting

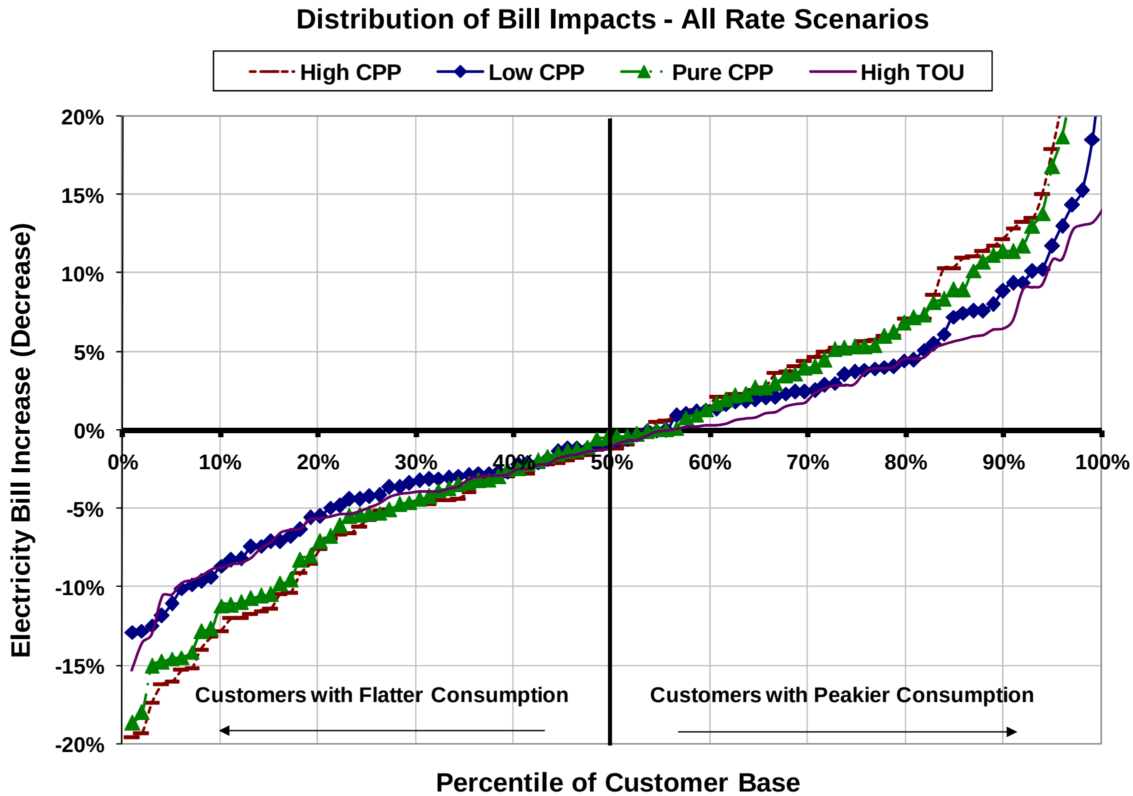
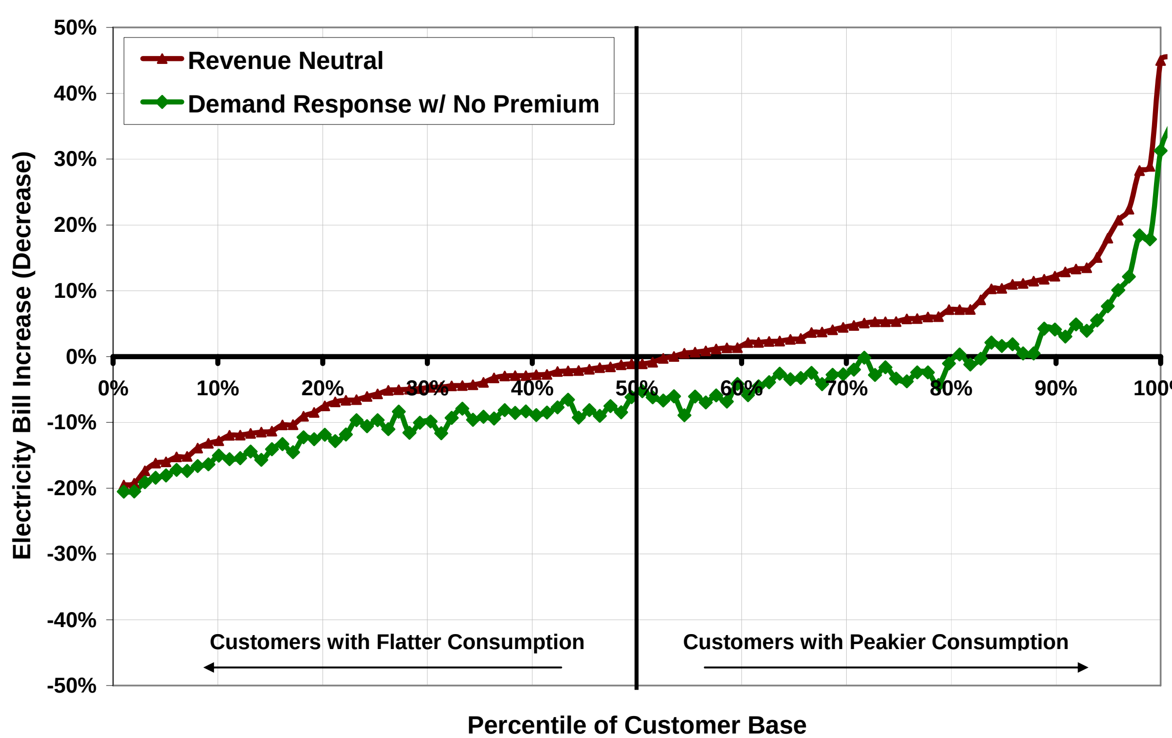


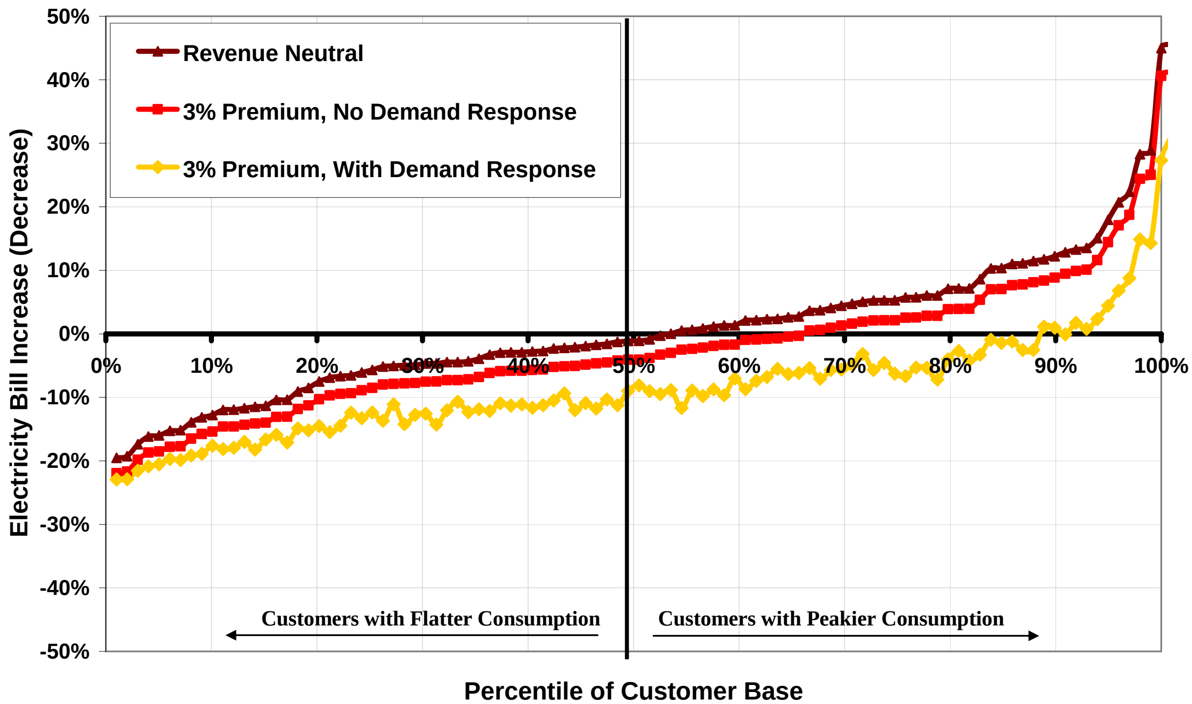
Figure 12: Distribution of Bill Impacts for CPP High Rate: With and Without Demand Response



Lastly we examine what happens to the bill savings under a CPP rate when we provide an "incentive" or hedging cost credit (reflecting the utility's savings from not incurring hedging costs) to increase the appeal of dynamic pricing. Figure 13 shows two results: (1) What happens to the distribution of bill impacts when customers on a CPP rate receive a hedging cost credit of 3 percent but do not shift load,[37] and (2) what happens to the distribution of bill impacts when customers on a CPP rate receive a hedging cost credit of 3 percent and shift their demand.

- Assuming no demand response, the middle dashed line in Figure 13 shows how the distribution of bill impacts shifts under the CPP High rate simply by adding a 3 percent hedging cost credit. Under this scenario, about 70 percent of all customers now experience bill savings even with no demand response.
- Finally, assuming both demand response and a 3 percent hedging cost credit under a CPP rate, the solid bottom line in Figure 13 shows that about 90 percent of all customers will now experience bill saving. This shows that offering a small hedging cost credit—such as 3 percent—to customers in combination with shifting load can make dynamic pricing appealing to 90 percent of customers.[38]

Figure 13: Distribution of Bill Impacts Under CPP High Rate
Assuming Demand Response and a Risk Premium Credit



[37] For illustration we are assuming a 3 percent hedging cost credit. The actual amount of the hedging cost credit will need to be estimated and is dependent on several factors. This is discussed at the conclusion of this section.

[38] If power is procured for all customers as a single risk pool (regardless of which rate they are on), then the hedging cost credit would be paid by the customers on less risky rates to the customers on more risky rates. However, if power is procured for each rate group separately, then there is no need for a hedging cost credit because the cost to serve customers on dynamic rates is lower than the cost to serve customers on static rates.

Calculating a Hedging Cost Premium

This section discusses how to calculate and "fund" this hedging cost credit. There are alternative methods for calculating a hedging cost premium.

First, let's consider Case #1 where all residential customers, for example, share the same risk pool. This means that, if no dynamic rates were offered, all customers would face the same static rate. Under this scenario, a revenue neutral dynamic rate is calculated based on a static rate. So, for example, if the static rate is $0.10 per kWh, then a revenue neutral CPP might have a critical price of $1.00 per kWh, a peak rate of $0.11 per kWh, and an off-peak rate of $0.08 per kWh. Pegging the CPP rate to the static rate to achieve revenue neutrality implicitly assumes that the underlying cost to serve is the same for all customers.

A hedging cost premium can be calculated based on the risk of serving the customer load under static rates.[39] Using a commonly used formula in financial analysis, the hedging cost premium can be expressed as a function of load volatility (i.e., the standard deviation of hourly loads), wholesale price volatility (i.e., the standard deviation of hourly prices), and the correlation between load and wholesale price:[40]

Hedging or Risk Premium = function (load volatility, spot price volatility, and correlation between load and spot price)

Hedging or Risk Premium = $\exp(\sigma_L \cdot \sigma_P \cdot \rho_{L,P})$

Where:
σ_L = Load volatility
σ_P = Spot price volatility
$\rho_{L,P}$ = Correlation between load and spot price

We calculated the hedging (or risk) premium for two areas in PJM—the PJM Eastern zone and the PJM ComEd zone using actual hourly price and load data over the period May 2004 through May 2007. The hedging (or risk) premium was estimated to be 15.7 percent for the PJM Eastern zone based on an actual price volatility of 0.03, an actual load volatility of 6.52, and a correlation of 0.76. In contrast, the hedging (or risk) premium for the ComEd zone was estimated to be 3.9%. This was based on the actual price volatility of 0.02, an actual load volatility of 2.37, and a correlation of 0.73. When risk premiums are high, as they are in the PJM Eastern zone, for example, it is especially important to recognize that maintaining the status quo with static rates may be very costly to customers. In the PJM Eastern zone, based on these estimates, customers on static rates are paying 15 percent more than they would pay if they faced spot prices.[41]

Now let's consider Case #2 where static rate customers and dynamic pricing customers are in two separate risk pools. Under this scenario, assume that the static rate is still $0.10 per kWh. These customers assume no risk and it is 15 percent more expensive to serve them compared to serving spot price customers. (Assuming the customers are in the PJM Eastern zone, the risk premium is about 15 percent as described above.) In this case, customers under the CPP rate are now in their own risk pool. Although we do not know the exact risk

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[39] A hedging cost premium is an estimate of the "premium" being paid by customers to avoid fluctuations in prices. This has no relationship to a "guaranteed rate," which is a pre-determined rate that is sometimes offered by energy marketers to attract new customers.

[40] Note that standard deviations are measures of volatility in financial analysis.

[41] See discussion and Appendix B in A. Faruqui, R. Hledik, and B. Neenan, "Rethinking Rate Design: A Survey of Leading Issues Facing California's Utilities and Regulators." August 2007.

premium for CPP, we know that it is less than 15 percent (the cost premium associated with the flat rate). For this example, assume that the risk premium for CPP is 5 percent.[42] The difference between these two risk premiums (i.e., 10 percent) can be viewed as the "cost premium credit." When the CPP customers are in the same risk pool as the flat rate customers, they basically pay a 15 percent cost premium, even though they are exposed to more risk, and should only pay a 5 percent cost premium. However, if they are moved to their own risk pool, the excess risk premium (10 percent in this example) disappears; this is the risk premium or hedging cost credit. As shown in Figure 13, providing a hedging cost credit to customers on dynamic rates would make such rates more appealing to more customers.[43]

[42] Since CPP customers are not typically in their own risk pool, the relevant risk premium cannot be directly calculated at this time.

[43] To our knowledge, no one has yet proposed a hedging cost credit.

SECTION V: DYNAMIC PRICING UNDER ALTERNATIVE MARKET STRUCTURES

Over the past decade, as the electric utility industry in the U.S. has reorganized, two market structures have emerged for providing electric power to consumers—deregulated markets and vertically integrated markets. In the Northeast and parts of the Midwest, traditional investor-owned utilities (IOUs) were unbundled into generation, transmission, and distribution companies. In these restructured markets, consumers purchase electricity either from the regulated distribution company (also called a load serving entity or LSE) or a competitive provider.[44] In much of the South and parts of the West, reorganization did not occur and the IOUs remain vertically integrated.

In this section, we examine the economics of dynamic pricing under alternative utility market structures—vertically integrated versus unbundled or deregulated. Our discussion focuses on a demand response to a price signal. The strategic purpose of such programs is to reduce the need for new capacity. However, even though capacity (and other) savings may be theoretically achievable, the practical matter is to understand how such savings are actually achieved. We use CPP as an example of dynamic pricing throughout this section.

As discussed in Section III, the benefits to the utility of dynamic pricing fall into four general categories: capacity savings, energy (i.e., fuel) savings, transmission savings, and distribution savings. As illustrated in the example in Section III, under a CPP rate, the capacity savings dominate the overall utility savings and represent well over half of the total savings to the utility. This is because CPP can reduce the need for additional peaking capacity resources. In areas where peak generation capacity is inadequate, another benefit of CPP is that it can improve system reliability and reduce the likelihood of an outage. Therefore, the value of the loss of load (VOLL) needs to be considered as an additional benefit.[45]

Dynamic pricing results in changes in load shapes and energy usage and a reduced need for peaking capacity. However, how these benefits are realized varies depending on the specific market structure for the utility—vertically integrated company, distribution company, or hybrid company (i.e., a company that has sold some but not all of its generation assets), the regulatory incentive mechanism in place for the utility, and the timing (short run vs. long run). Table 17 provides a breakout of the different possibilities and examples of utility companies that fit into each category. These categories are discussed below.

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[44] In the mass market, the utility distribution company is typically still providing electricity to all or a large percentage of customers. This is referred to as default service, standard offer service, or provider of last resort. In some restructured markets there are no "competitive" service providers so the legacy IOU provides electricity to 100 percent of the mass market customers. The service provided to large C&I customers is much more competitive and is not discussed in this paper.

[45] Lisa Wood, "Measuring the Reliability Benefits of Critical Peak Pricing." Draft discussion paper. 2007.

Table 17: Market Structure by Cost Recovery Mechanism: Example Utility Companies

	Market Structure		
Cost Recovery Mechanism	Vertically Integrated Company	Unbundled Distribution Company	Hybrid Company
Decoupling or "true up" mechanism	Idaho Power	Baltimore Gas & Electric, Potomac Electric Power Co.	Pacific Gas & Electric, Southern California Edison
No decoupling or true up	Florida Power & Light	Several utilities in Northeast	

Vertically Integrated Utility

For a vertically integrated utility, demand response from dynamic pricing can be viewed as a resource on the same footing as supply-side resources and included in its integrated resource planning (IRP) process.[46] However, in the short run, whether a state has a revenue decoupling mechanism in place will determine how dynamic pricing impacts the utility's bottom line and whether the benefits are actually realized.

Decoupling is a rate adjustment or automatic "true up" mechanism which ensures that the utility recovers its fixed costs (i.e., investments in power plants, transmission lines and distribution network) from the amount of electricity that is actually sold.[47] The purpose of decoupling is to adjust rates so that those fixed costs whose recovery was approved in the utility's prior rate case are recovered. This occurs at regular intervals. Decoupling is not applied to variable cost components such as fuel costs and purchased power. Under a decoupling mechanism, utilities collect revenues based on a pre-determined revenue requirement and, on a periodic basis, actual revenues are trued-up to the revenue requirement.[48] Decoupling removes a utility's financial disincentive for engaging in demand-side programs (by ensuring that the utility will recover its fixed costs), but if misapplied, it may also simultaneously remove the customer's incentive for participating in such programs.

It is important that steps be taken to avoid the creation of zero sum outcomes. Example 1 shows how such an adverse outcome can easily occur.

Example 1. This example describes how decoupling works for a vertically integrated utility that offers a dynamic pricing program. When dynamic pricing results in lost revenue, it can potentially harm the earnings of the utility. The key issue is recovery of revenues that would have been used to recover fixed costs and not revenues that would have been used to recover variable costs, since failure to recover the latter does not affect the utility's earnings. The reason is that variable revenues and costs go down by the same amount and cancel out while fixed revenues go down but fixed costs do not go down (by definition).

Assume that the fixed cost portion of the revenue requirement for a utility is $45 per customer and that a utility has 1,000 customers. Once it implements a dynamic pricing program, the utility finds it is only receiving a $40 contribution to fixed costs per customer. Hence, the loss of $5 per customer needs to be recaptured for the utility to fully recover its fixed costs. What happens under different program participation assumptions in the short run? By short run, we mean that the revenue requirement that is in place did not account for the dynamic pricing program.

[46] In California, energy efficiency is on an equal footing with supply side resources.

[47] For a recent discussion of decoupling, see NARUC, "Decoupling for Electric and Gas Utilities Frequently Asked Questions." September 2007.

[48] Rates are set by dividing the revenue requirement by expected sales. Under decoupling, these rates get adjusted to collect target revenues based on actual sales.

- If 100 percent of customers participate in a dynamic program, the utility will recover $5 per customer under decoupling (a total of $5,000) and the $5 savings to all customers will decrease to zero (as if there were no dynamic pricing program). This would nullify the intent of the program and eliminate all participants.
- In contrast, if 10 percent of customers (i.e., 100 customers) participate in a dynamic pricing program, the utility will need to recover $500 (i.e., $5 per customer based of a total of 100 participants). The utility will recover this $500 from all customers. Therefore, the 1,000 customers will pay $0.50 each. This means that the participants will save a net of $4.50 (5.00 less $0.50) and that each non-participant will pay $0.50 more to provide adequate revenue for the utility.

In the short run, decoupling creates an incentive for dynamic pricing. In the long run, once the utility incorporates this expected savings from dynamic pricing into its revenue requirement, the future fixed cost portion of the revenue requirement is adjusted so no true up is required.

If there is no decoupling or true-up mechanism and the utility is vertically integrated, then capacity and other savings from dynamic pricing programs are realized by the utility. However, regulatory lag may influence the timing for realizing these savings.

Unbundled Distribution Company

Example 2. This example describes how decoupling works for a distribution company or LSE that offers a dynamic pricing program and is the standard offer service (SOS) provider.[49] Typically, an unbundled distribution company that is contracting for power to supply its SOS customers will enter into full requirements contracts for all power requirements and will use a true-up mechanism to reconcile the cost of purchasing the power with the revenues generated. As is the case with the vertically integrated utility, the benefits of dynamic pricing will be lost if the full requirements contracts do not take into account the changes in load shapes and energy usage induced by dynamic pricing, which lowers costs for all customers.

Distribution companies typically offer dynamic pricing in conjunction with the deployment of advanced metering infrastructure to capture additional benefits. However, changes in the types of power contracts, the true-up mechanism, and/or the power procurement process may be required for these distribution companies and their customers to fully realize the benefits of dynamic pricing.

Realizing the Benefits of Dynamic Pricing Under Alternative Market Structures

Whether dealing with a vertically integrated utility or an unbundled distribution company, the simple truth is that dynamic pricing customers cost less to serve than static pricing customers. Therefore, the “one size fits all” pricing concept for electricity is not economically sensible, and forcing customers that are flexible and responsive to subsidize those that are not makes little sense. While some may argue that consumers are overburdened with choices and don’t want to worry about electricity, today’s technologies can make it effortless for electricity customers to participate in dynamic pricing programs. On the other hand, some customers do like choices and want to be living in the “digital age” or have the latest options when it comes to their electric buying behavior.

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[49] The distribution company is the SOS provider for the vast majority of mass market customers in the U.S., so we use this as the example.

So how does one develop a pricing program that rewards customers for engaging in demand response? In the case of a vertically integrated utility, the key is to align costs and rates. If the avoided cost of critical peaking capacity is $1 per kWh, the rates should be set at $1.00 per kWh. When the customer curtails usage, the utility loses a dollar of revenue, but that equals the cost of peaking capacity, so there is no net loss that has to be recovered. If there is an overall drop in energy consumption as well, then the usual mechanisms that are used for making the utility whole with respect to energy efficiency programs can be used.

In the case of an LSE, the likely situation is that most mass market customers will be on standard offer service. The LSE will procure the power for their needs but most likely this will occur via a contract that does not recognize the benefits of dynamic pricing. Wholesale rates will be static, say $0.10 cents per kWh. Thus, if the CPP rate is $1.00 per kWh, the customer will have a significant incentive to curtail usage. However, when a customer curtails 1 kWh, that customer saves $1.00, but the utility only saves $0.10 cents, creating a net loss of $0.90 cents per kWh that has to be recovered.[50] One way around this is to re-bid the procurement contracts separately for critical peak periods, thereby bringing costs and rates into alignment. Another option is to procure power separately for the two different pools of customers: those on dynamic pricing and those on a static rate. A third option is a single procurement that provides different prices for dynamic versus static rate customers.

In this section, we've touched on some of the issues surrounding dynamic pricing and how to ensure that the benefits are realized in practice. Several factors are influential, including the particular market structure, whether a decoupling mechanism is in place, and whether the changes in load shape and energy usage resulting from dynamic pricing have already been taken into account. At this point in time, only a few states have a decoupling mechanism in place. Therefore, the more widespread issue is how distribution companies can adjust their power contracts and/or their power procurement contracts to fully realize the benefits of dynamic pricing.

[50] As discussed, if this loss is recovered via a true-up, the benefits from dynamic pricing will be lost.

SECTION VI: ALTERNATIVE METHODS AND TECHNOLOGIES FOR ACHIEVING DEMAND RESPONSE GOALS

Dynamic pricing options such as critical peak pricing, peak-time rebates, and real-time pricing require that participating customers be equipped with AMI or some type of meter that can record hourly loads. However, if the objective of dynamic pricing is to achieve demand response, then other ways for achieving demand response should also be considered. In this section we discuss these other ways but only at the "retail" level; we do not consider ISO or regional transmission organization (RTO) programs in this section.

Historically, utilities have largely relied on direct load control (DLC) programs and TOU rates to achieve demand response. In contrast to dynamic pricing options (such as CPP, PTR, and RTP), DLC programs can be implemented utilizing the existing metering infrastructure by simply installing a switch on the compressor of the central air conditioner that is operated via a radio signal. DLC programs (as well as interruptible rates) provide utilities with a high degree of control over load reductions. Likewise, TOU rates do not require AMI for implementation. TOU customers are typically metered using a time-of-use meter, which separately captures their total consumption during the peak and off-peak periods. TOU rates give utilities the ability to influence peak consumption through rate design by charging a higher rate during the peak period than the off-peak period, but unlike DLC, they cannot be dispatched in real time.

Direct Load Control

DLC is the most widely offered residential DR program in the U.S. Participation in these programs is typically voluntary and the reduction in demand is controlled remotely by the utility via a switch on the participant's central air conditioner. Some of the newer programs are using smart thermostats instead of switches.

Most DLC programs offer a flat monthly incentive to allow the utility to control the central air conditioner. On average, customers on a DLC program are likely to reduce their peak demand by about 1 kW. Under DLC, when warranted by capacity shortages, a customer's central air conditioning system is turned down or cycled by the utility. The exact days and the length of the cycling period are not known in advance, and typically the program participant is not even aware that the cycling has been triggered. Participants sometimes have the option to override a small number of interruptions each year.

Although utility-based DLC programs do result in demand response and have been effective in smoothing peak demand, they also raise equity concerns.[51] Since participation is voluntary and the exact load reduction is not measured, participants who provide little load reduction are paid the same amount as those that provide significant load reduction. In general, because there is no direct relationship between the dollar value of system benefits actually achieved and the incentives paid to the participants, incentive payments can exceed system benefits. If and when this occurs, the non-participants bear the cost. This raises concerns because

[51] See K. Herter, "Residential Implementation of Critical Peak Pricing of Electricity," Energy Policy 35, 2007. pp 2121-2130.

DLC programs are restricted to customers with central air conditioning. Therefore, customers without CAC—non-participants by definition—cannot realize benefits from DLC, although they can incur costs.

Many utilities have effectively implemented successful DLC programs. Most recently, Hydro One in Ontario, Canada, launched a new residential DLC program in summer 2006. Their program provides customers with a free smart thermostat that allows participants and the utility to control the setting on their central air conditioning remotely over the Internet. The technology also gives Hydro One the ability to increase the temperature of the participant's house up to a maximum of two degrees Celsius during critical events in the summer.

Time-of-use Pricing

TOU rates are common with residential customers and have been deployed widely across the U.S. for the past 30 years. However, TOU rates are relatively inefficient in achieving load reduction on the most critical days relative to dynamic prices such as CPP or RTP for two reasons. First, because the peak price is typically not that much higher than the off-peak price, this relationship limits the load reduction benefits resulting from TOU. Second, because the very small percentage of critically important hours of the year (typically 60 to 100 hours of the 8,760 hours in the year) are priced the same as the other peak hours, customer load reductions on critical days, rather than being higher because wholesale prices are higher, are typically the same as on non-critical days. Therefore, TOU rates do not track the costs of providing electricity very well.

Salt River Project (SRP) and Arizona Public Service (APS) are examples of utilities that have successfully implemented residential TOU rates. In the Phoenix area, these utilities have enrolled nearly one-third of their customers on TOU rates. APS offers multiple TOU options to encourage a higher rate of participation, and combines one of the options with a demand charge. Both utilities have stressed the importance of educating customers about the rates, potential bill savings, and benefits to the grid.

The province of Ontario is currently rolling out AMI. By 2010, it is expected that all customers will be on default TOU rates. These rates will feature three pricing periods, with peak period prices for electric generation being three times the off-peak period price and the mid-peak period price two times the off-peak period price.

Summary

In this section, we've summarized the two major alternatives to dynamic pricing for achieving demand response that are in widespread use today—DLC and TOU rates. While the benefits achieved by these alternatives may not be as high as the benefits achieved by dynamic pricing (the benefits of TOU relative to CPP were provided earlier in this paper), the costs of implementation may be significantly lower.

In considering the costs and operational benefits of dynamic pricing versus DLC or TOU, the costs and operational benefits of the existing metering technology (i.e., on foot or drive by) and the cost of switches for DLC or the cost of a time-of-use meter for TOU relative to the cost and benefits of AMI (and the costs of the associated switches or smart thermostats), need to be considered. Hardware costs as well as communications infrastructure, installation and maintenance, and program costs must be taken into account.

Incremental operational benefits and costs will depend, in part, on the starting point for each utility. For example, for a utility that already has drive-by meter reads, the incremental operational benefit to AMI will not be as great as when going from foot read meters to AMI. Ultimately, both costs and benefits (both operational and rate-induced benefits) must be considered in making decisions about the most cost-effective method for achieving demand reductions.

APPENDIX A: PRISM IMPACTS MODEL

The PRISM Impacts Model consists of four worksheets. The purpose of each worksheet is described below.

PRISM Impacts Inputs

All user-defined inputs to the model are entered into the PRISM Impacts Inputs worksheet. In the All-in Rate table, the user enters both the current rate and the critical peak pricing (CPP)/time of use (TOU) rate that is being analyzed. These rates are entered as all-in rates. In other words, they incorporate generation charges, any other variable charges, and any fixed charges on a $/kWh basis. The CPP/TOU rate is entered for the critical peak, peak, and off-peak periods (as appropriate for the specific rate).

In the Average Customer Usage Distribution table, the user enters the “typical” customer’s average consumption during peak and off-peak periods on both critical and non-critical days. This version of the model is currently set up to accept load shapes for the average residential customer, the average customer with central air conditioning (CAC), and the average customer without CAC for a hypothetical utility. These could be replaced with other residential customer types.

In the CAC Saturation table, the user enters the CAC saturation for the region. In this hypothetical example, the saturation is assumed to be 75 percent.

In the Weather Data table, the user enters the weather conditions for the region of interest. The weather conditions are based on cooling degree-hours data.

Elasticity Estimates

The inputs from the PRISM Impacts Inputs worksheet are used in the Elasticity Estimates worksheet. This worksheet contains the PRISM model coefficients that were estimated from the data obtained during the California Statewide Pricing Pilot (SPP). The model coefficients, when combined with the input parameters, produce elasticity estimates by customer type and day type.

Impacts per Participant

The Impacts per Participant worksheet reads in each customer type’s load shape and rate and, using the elasticities calculated in the Elasticity Estimates worksheet, calculates the average kWh-per-hour reduction for each period (i.e., peak period during critical days, off-peak period during non-critical days, etc). This is also represented as the percent reduction in demand during each period.

Impact Summary

The Impact Summary worksheet simply summarizes the output that is calculated in the Impacts per Participant worksheet. Table A-1 provides an example of the results summary worksheet assuming a critical peak price of $1.30 per kWh, a peak price of $0.14 per kWh, and an off-peak price of $0.083 per kWh. This worksheet provides two impacts: the change in consumption in the peak and off-peak periods by day type in terms of kWh per hour, and percentage change from the original load. These results show that the change in consumption during critical peak hours for the average residential customer is a reduction of 24 percent.

Table A-1: Example of PRISM Results Summary Worksheet

Change in Consumption, by Customer Type (kWh per Hour)

	Residential			
	Average	**CAC**	**No CAC**	**CAC + Tech**
Critical Days - Peak	-0.65	-0.81	-0.20	-1.06
Critical Days - Off-Peak	0.09	0.10	0.05	0.13
Non-Critical Days - Peak	-0.04	-0.05	-0.01	-0.07
Non-Critical Days - Off-Peak	0.04	0.05	0.01	0.07

Change in Consumption, by Customer Type (% of Original Load)

	Residential			
	Average	**CAC**	**No CAC**	**CAC + Tech**
Critical Days - Peak	-24.2%	-28.4%	-10.6%	-36.9%
Critical Days - Off-Peak	4.7%	4.8%	4.0%	6.2%
Non-Critical Days - Peak	-2.6%	-3.1%	-1.3%	-4.0%
Non-Critical Days - Off-Peak	3.1%	3.7%	1.2%	4.9%

APPENDIX B: PRISM BENEFITS MODEL

The PRISM Benefits Model consists of several spreadsheets, the purposes of which are described below.

Customer Forecast

The market forecast spreadsheet allows the user to input the number of customers, the growth rate, the CAC saturation, and the enabling technology saturation. The worksheet also allows the user to roll out advanced metering infrastructure (AMI) over a period of four years rather than instantaneously, and incorporates a deployment ramping rate that represents how quickly customers can be enrolled in and started on the dynamic pricing program. The user also specifies the specific participation scenario (opt in, opt out, mandatory, or peak-time rebate (PTR) awareness) as well as the percentages. This information is used to compute the number of program participants by customer type under each option (e.g., opt in or opt out) over the forecast horizon.

PRISM Benefits Inputs

Many of the user-defined inputs to the cost-benefit analysis (CBA) model are entered into the PRISM Benefits Inputs spreadsheet. The first is the demand response for each type of hour by customer class. This is an output of the PRISM Impacts Estimation model. This hourly reduction in demand is adjusted by a set of user-defined factors. These factors represent savings on losses during transmission and capacity reserve requirements that no longer need to be fulfilled. The adjusted reduction is an estimate of the total avoided kW. This spreadsheet also contains the user-defined weighted average cost of capital (WACC) rate and the user-defined forecast of the number of customers participating in the dynamic rate. Finally, the spreadsheet contains the average monthly kWh consumption per customer in each class.

Capacity Value per Customer

The Capacity Value per Customer spreadsheet calculates the avoided capacity costs per customer based on the adjusted average hourly reduction in demand from the PRISM Benefits Inputs worksheet and an assumed capacity price. The present value of avoided capacity costs per customer is computed for a 15-year period using the WACC from the PRISM Benefits Inputs worksheet.

Energy Value per Customer

The Energy Value per Customer spreadsheet uses the adjusted demand response from the PRISM Benefits Inputs spreadsheet and applies a user-defined locational marginal price (LMP) value (as a proxy for the marginal cost of electricity) to calculate the total annual savings resulting from energy only. The present value of avoided capacity costs per customer is computed for a 15-year period using the WACC from the PRISM Benefits Inputs worksheet.

Transmission Value per Customer

The Transmission Value per Customer spreadsheet uses one user-defined variable that represents the total cost of transmission infrastructure on a $/kW basis. This input is then applied to the adjusted demand response for each customer class from the PRISM Benefits Inputs spreadsheet to calculate the annual per-customer transmission savings. The present value of transmission savings per customer is computed for a 15-year period using the WACC from the PRISM Benefits Inputs worksheet.

Distribution Value per Customer

Similar to the Transmission Value per Customer spreadsheet, the key user-defined variable in this worksheet is an all-encompassing cost of distribution infrastructure on a $/kW basis. This is applied to the adjusted demand response values from the PRISM Benefits Inputs worksheet to determine the annual savings from distribution infrastructure. The present value of distribution system savings on a per-customer basis is computed for a 15-year period using the WACC from the PRISM Benefits Inputs worksheet.

Price Mitigation Value per Customer

This worksheet computes the expected short-term reduction in wholesale prices resulting from lower peak demand due to dynamic pricing. The user-defined inputs are for the expected price reduction per 1 percent of demand response, the average LMP during critical peak hours, the energy demand during the critical peak period, a demand growth rate assumption, and the peak load forecast for the control area. The spreadsheet uses these inputs to calculate the peak load reduction and the reduction in the critical peak LMP. These calculations are then applied to the critical peak demand forecast. The present value of these savings represents the Price Mitigation value.

APPENDIX C: THE CALIFORNIA STATEWIDE PRICING PILOT SUMMARY[1]

California experienced a major power crisis in its unregulated wholesale markets during 2000 and 2001. The crisis was exacerbated by the lack of dynamic pricing in retail markets, which would have given customers an incentive to lower loads during peak times. One of the unknowns in implementing dynamic pricing is whether and by how much customers would reduce peak loads in response to dynamic price signals.

To help address this uncertainty, California's three investor-owned utilities, in concert with the two regulatory commissions, conducted an experiment to test the impact of TOU and dynamic pricing among residential and small commercial and industrial customers. The primary objectives of California's Statewide Pricing Pilot (SPP) were to:

- Estimate the average impact of time-varying rates on energy use by rate period and develop models that can be used to predict impacts under alternative pricing plans
- Determine customer preferences and market shares for time-varying rate options
- Evaluate the effectiveness of, and customer perceptions about, pilot features and educational materials

This evaluation report addresses the first objective. A previous report presented preliminary impact estimates for selected pilot treatments from the initial summer of the pilot (2003). This report updates and significantly extends those results. It is a comprehensive, stand-alone document and there is no need to review the previous report. Any discrepancies between results presented previously and those presented here reflect methodological enhancements, and therefore should be resolved in favor of the current report.

The SPP involved some 2,500 customers and ran from July 2003 to December 2004. Several different rate structures were tested. These included a traditional TOU rate, where price during the peak period was roughly 70 percent higher than the standard rate and about twice the value of the price during the off-peak period. The SPP also tested two varieties of CPP tariffs, where the peak period price during a small number of critical days was roughly five times higher than the standard rate and about six times higher than the off-peak price. One CPP rate, CPP-F, had a fixed critical peak period and day-ahead notification. The other CPP rate, CPP-V, had a variable peak period on critical days and day-of notification. CPP-V customers had the option of having an enabling technology installed free of charge to help facilitate demand response. The SPP also tested an information treatment that urged customers to reduce demand on critical days in the absence of time-varying price signals.

[1] This information is taken from the Executive Summary of the final report, "Impact evaluation of the California statewide pricing pilot," March 16, 2005. The report can be accessed on the web at: http://www.energy.ca.gov/demandresponse/documents/index.html#group3.

Methodological Overview

Both the overall design of the SPP and the evaluation approach underlying the results presented here allow not only for estimation of the impact of the specific price levels tested in the SPP, but also for estimation of demand response for prices that were not explicitly used as part of this experiment. The experimental design included control groups that stayed on the standard tariff and treatment groups that were placed on new time-varying tariffs or information programs. The treatment groups for each tariff were divided into subgroups that faced different price levels so that statistical relationships between energy use by rate period and prices could be estimated.

These statistical relationships, referred to as demand models, were used to estimate the demand response impact for the average prices used in the SPP. Importantly, they can also be used to estimate the impact of other prices that are within a reasonable range of those tested. Most of the demand models also allow adjustment of the magnitude of price responsiveness to account for variation in climate and the saturation of central air conditioning. Thus, demand response impact estimates can be developed for customer segments with characteristics that differ from those included in the experiment.

As noted above, the data used to estimate demand models includes information on both treatment and control customers. For treatment customers, information on energy use by rate period is available both before and after being placed on the new rate. This type of database allows separation of the impact of the experimental treatments from the impact of other factors that might influence energy use, including self-selection bias.

The demand system estimated for each tariff consists of two equations. One equation predicts daily energy use as a function of daily price and other factors. The second equation predicts the share of daily energy use by rate period. This type of demand system is commonly used in empirical analysis of energy consumption. While the complexity of the experimental design has created numerous empirical challenges, these challenges have been addressed through careful application of widely accepted statistical methods.

Residential Sector Summary

Three rate treatments were examined for residential customers: CPP-F, CPP-V, and TOU. An Information Only treatment was also examined. The CPP-F and TOU rates were implemented among a statewide sample of customers. The sample size for the CPP-F treatment was much larger than for the TOU treatment and the results were more robust. The CPP-V rate was implemented only in the San Diego Gas & Electric (SDG&E) service territory and the Information Only treatment in the Pacific Gas and Electric (PG&E) service territory.

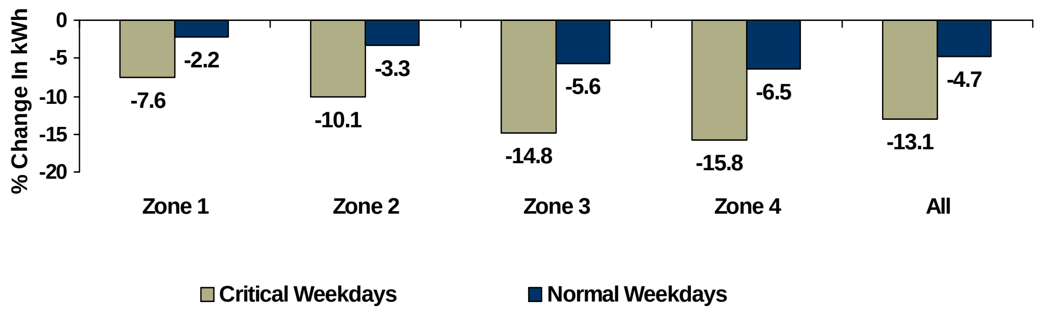
CPP-F Impacts

A key focus of the SPP was to assess the impact of dynamic tariffs. Estimated impacts vary on critical days (when the highest prices are in effect), normal weekdays (when lower peak prices are in effect), and weekends (which have the same prices as off-peak weekday periods).

Figure 1-1 summarizes the impact of the average CPP-F prices on energy use during the peak period on critical and normal weekdays. Statewide, the estimated average reduction in peak-period energy use on critical days was 13.1 percent. Impacts varied across climate zones, from a low of -7.6 percent in the relatively mild climate of Zone 1 to a high of -15.8 percent in the hot climate of Zone 4. The average impact on normal weekdays was -4.7 percent, with a range across climate zones from -2.2 percent to -6.5 percent.

The statewide impact estimate of -13.1 percent has a 95 percent confidence band of +/- 1 percentage point. This means that there is a 95 percent probability that the actual reduction in peak-period energy use on critical days based on average SPP prices would fall between 12.1 and 14.1 percent.

Figure 1-1: Percent Change in Residential Peak-Period Energy Use
(Avg CPP-F Prices/Avg 2003/2004 Weather)



Other key findings for the CPP-F rate include:

- Differences in peak-period reductions on critical days across the two summers, 2003 and 2004, were not statistically significant.
- Differences in impacts across critical days when two or three critical days are called in a row (as might occur during a heat wave) were not statistically significant.
- Average impacts on critical days were greater during the hot summer months of July through September (the "inner summer") than during the milder months of May, June and October (the "outer summer").
- Households with central air conditioning were more price responsive and produced greater absolute and percentage reductions in peak-period energy use than did households without air conditioning.
- Demand response impacts were lower in the winter than in the summer, and lower during the milder winter months of November, March and April (the "outer winter") than during the colder months of December, January and February (the "inner winter").
- There was essentially no change in total energy use across the entire year based on average SPP prices. That is, the reduction in energy use during high-price periods was almost exactly offset by increases in energy use during off-peak periods.

As previously mentioned, one of the primary advantages to developing demand models is the ability to estimate the impact of prices that were not specifically tested in the SPP.

Figures 1-2 and 1-3 show how the percentage reduction in peak-period energy use on critical days varies with changes in the peak-period price on critical days (when everything else is held constant). The curves indicate that the reduction in peak-period energy use increases as prices increase, but at a diminishing rate. Figure 1-2 shows that reductions are greater in percentage terms (and even greater in absolute terms) in hotter climate zones (where air conditioning saturations are high) than in cooler zones. Figure 1-3 shows that reductions are greater in the inner summer months of July, August and September than in the outer summer months of May, June and October. We believe the greater responsiveness in the inner summer is due primarily to the influence of air conditioning.

Figure 1-2: Percent Reduction in Peak-Period Energy Use on Critical Days
Average Summer, 2003/04

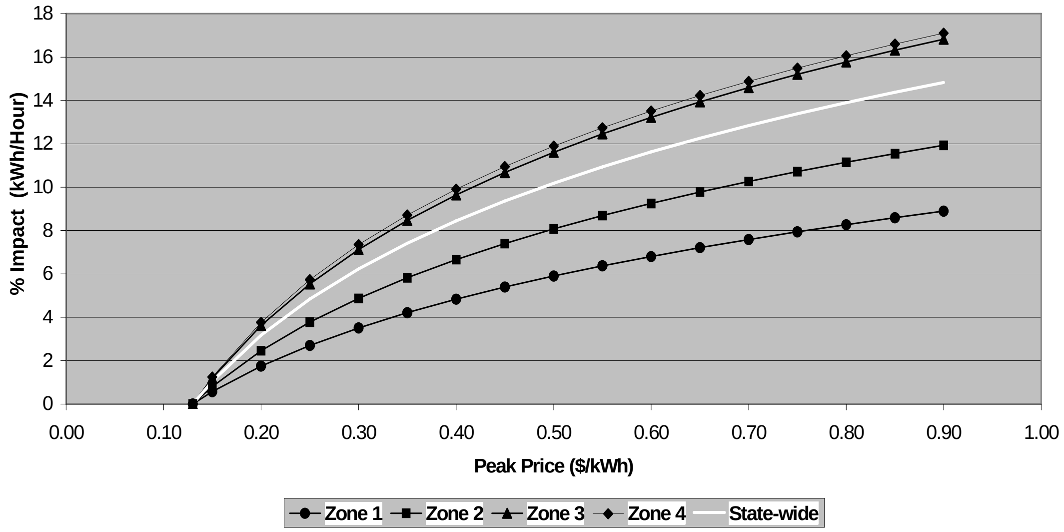
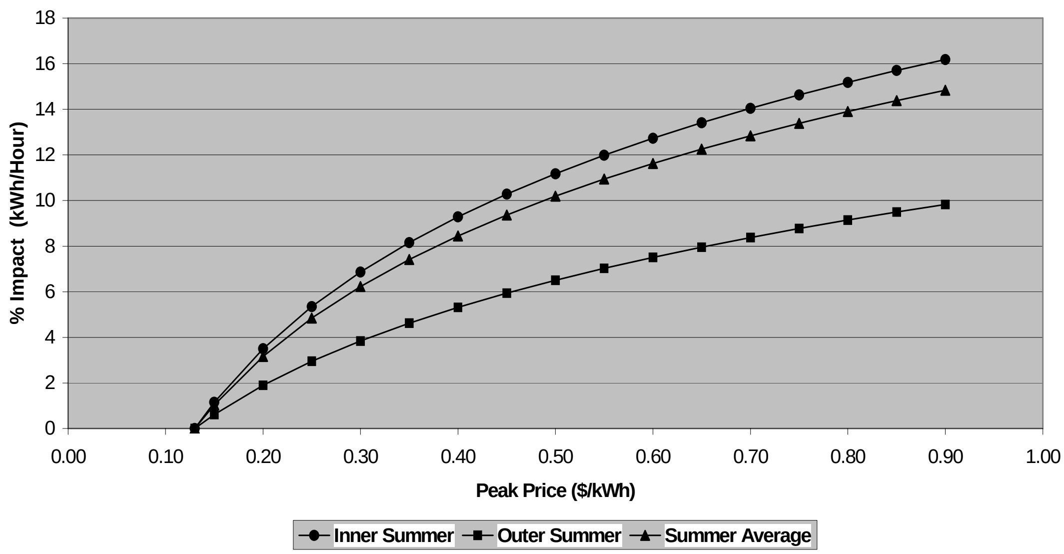


Figure 1-3: Percent Reduction in Peak-Period Energy Use on Critical Days by Season



TOU Impacts

The reduction in peak-period energy use resulting from TOU rates in the inner summer of 2003 equaled -5.9 percent. This 2003 value is comparable to the estimate for the CPP-F tariff on normal weekdays when prices were similar to those for the TOU treatment. However, in 2004, the TOU rate impact almost completely disappeared (-0.6 percent). TOU winter impacts are comparable to the normal weekday winter impacts for the CPP-F rate.

Drawing firm conclusions about the impact of TOU rates from the SPP is somewhat complicated by the fact that the TOU sample sizes were small relative to the CPP-F sample sizes. Small sample sizes are more subject to influence by outliers and changes in the sample composition over time. Further complicating the estimation of the daily energy equation is that variation in daily prices over time is quite small, which makes it difficult to obtain precise estimates of daily price responsiveness. In short, there are reasons to take the analysis of the TOU rate treatment with a “grain of salt.” Indeed, an argument can be made that the normal weekday elasticities from the CPP-F treatment may be better predictors of the influence of TOU rates on energy demand than are the TOU price elasticity estimates.

On the other hand, if the TOU results are accurate, they have very important policy implications, since they suggest that the relatively modest TOU prices tested in this experiment do not have sustainable impacts.

CPP-V Impacts

The residential CPP-V rate was tested among two different populations, both within the SDG&E service territory.

Track A customers were drawn from a population of customers with average summer energy use exceeding 600 kWh per month. The saturation of central air conditioning among the Track A treatment group was roughly 80 percent, much higher than among the general population, and average income was also much higher. Track A customers were given a choice of having an enabling technology installed free of charge to facilitate demand response. About two-thirds of participants took one of three technology options and about half of those selected a smart thermostat.

Track C customers were recruited from a sample of customers that had previously volunteered for the AB 970 Smart Thermostat pilot. All Track C customers had smart thermostats and central air conditioning.
Key findings for the CPP-V rate treatments include:

- The reduction in peak-period energy use for Track A customers on critical days equaled almost 16 percent, which is about 25 percent higher than the CPP-F rate average.
- The peak-period reduction for the Track C treatment equaled roughly 27 percent. About two-thirds of this reduction can be attributed to the enabling technology, and the remainder is attributable to price-induced behavioral changes.

Although comparisons between Track A and Track C CPP-V treatments and between the CPP-V and CPP-F treatments must be made carefully due to differences in sample composition, the Track C results suggest that impacts are significantly larger with enabling technology than without it. The 27 percent average impact for the Track C CPP-V treatment is roughly double the 13 percent impact for the CPP-F rate for the average summer. It is also substantially larger than the Track A CPP-V treatment impact, where only some customers took advantage of the technology offer.

Information Only Impacts

The Information Only treatment was included primarily as a crosscheck on the results of the CPP-F rate treatment. Specifically, the purpose was to determine whether simply appealing for a reduction in energy use on critical days might produce significant impacts even in the absence of any price incentive. Information Only customers were given educational material regarding how to reduce loads during peak periods, and they were notified in the same manner as were CPP-F customers when critical days were called. However, participants were not placed on time-varying rates.

The Information Only treatment was implemented in two climate zones in the PG&E service territory. In one of the two zones in 2003, demand response was statistically significant while in the other zone it was not. In 2004, there was no evidence of any response in either zone. At a minimum, one can conclude that demand response in the absence of a price signal is not sustainable. Furthermore, we believe it is not unreasonable to consider the 2003 impact for a single climate zone to be an anomaly and to conclude that there is no clear evidence from the SPP of any significant impact from an appeal to reduce energy use on critical days in the absence of a price signal.

Residential Summary

Table 1-1 summarizes the key findings with regard to reductions in peak-period energy use resulting from the various tariff options tested in the SPP.

The most robust and generalizable estimates from the SPP are for the CPP-F rate. TOU rate impacts vary across years and are suspect due to sample size limitations and other factors. We recommend using the CPP-F models to predict TOU impacts. Although the Track C CPP-V results are more difficult to generalize to the overall population, they provide useful estimates of the incremental impact of prices and enabling technology.

It is interesting to compare the results obtained from the SPP with those that have been found elsewhere. There have been dozens of studies of the impact of time-varying rates conducted over the years, many of them quite dated.[2] Very few previous studies examined dynamic rates, which were a key focus of the SPP. Making comparisons across studies is very difficult because of differences in methodology, differences in the characteristics of underlying populations, and differences in price levels and other factors. Ignoring such complexities, a simple comparison shows that the SPP estimates of price responsiveness in California are at the low end of the range reported in the literature.

[2] Chris S. King and Sanjoy Chatterjee. *Predicting California Demand Response.* Public Utilities Fortnightly, July 1, 2003.

Table 1-1
Summary of Average Peak-Period Impacts by Treatment Type for Residential Customers

Treatment	Day Type	Avg. Price (¢/kWh)[3]	Impacts	Comments
Track A CPP-F	**Critical Weekday**	P = 59 OP = 9 D = 23 C = 13	-13.1% average summer -14.4% inner summer -8.1% outer summer	No statistically significant difference for inner summer between 2003 and 2004 (differences across the two years can not be estimated for the outer summer or the average summer)
	Normal Weekday	P = 22 OP = 9 D = 12 C = 13	-4.7% average summer -5.5% inner summer -2.3% outer summer	Difference between critical & normal days is primarily due to price differences and secondarily to differences in weather
Track A TOU	**All Weekdays**	P = 22 OP = 10 D = 13 C = 13	-5.9% inner summer 2003 -0.6% inner summer 2004 -4.2% outer summer 2003/04	Results are suspect because of the small sample size and observed variation in underlying model coefficients across the two summers. Recommend using normal weekday CPP-F model to predict for TOU rate.
Track A CPP-V	**Critical Weekday**	P = 65 OP = 10 D = 23 C= 14	-15.8% average summer 2004 Represents average across households with and without enabling technology—could not separate price & technology impacts	Not directly comparable to CPP-F results due to differences in population (CAC saturation for CPP-V treatment group twice that of CPP-F; CPP-V average income much higher; 2/3 of CPP-V customers had enabling tech.; all households located in SDG&E service territory)
	Normal Weekday	P = 24 OP = 10 D = 14 C = 14	-6.7% average summer 2004	See above comments about population differences
Track C CPP-V	**Critical Weekday**	Same as for Track A	-27.2% combined tech & price impact for average summer 2003/04 -16.9% impact for tech only -11.9% incremental impact of price over & above tech impact	Not directly comparable to Track A results due to population differences (All Track C customers are single family households with CAC located in SDG&E service territory). Some evidence that impacts fell between 2003 & 2004
	Normal Weekday	Same as for Track A	-4.5% average summer 2003/04	See above comments about population differences
Track A Info Only	**Critical Weekday**	13 for all periods	Statistically significant response in one of two climate zones in 2003. No response in 2004.	Analysis provides no evidence of sustainable response in the absence of price signals.

[3] P = peak period price; OP = off-peak price; D = daily price; C = control group price.

One study, conducted in the early 1980s by the Electric Power Research Institute,[4] allows for a more careful comparison between the SPP results and estimates based on several of the well-designed TOU rate experiments that were conducted in the late 1970s. The EPRI study used a model specification similar to the one used here so that we were able to estimate the impact of SPP prices using the price responsiveness measures from the EPRI study. Using these earlier model parameters along with average SPP prices, the estimated peak-period reduction on critical days is roughly 70 percent greater than the estimated value from the SPP (i.e., -22.5 percent versus -13.1 percent).

Based on these comparisons, it would appear that price responsiveness in California today is less than it was in California and elsewhere a quarter century ago. This is not surprising in light of the significant conservation and load management programs that were implemented in the past 25 years. Actions taken by many consumers following the energy crises of 2000 and 2001 may also have reduced the ability or willingness of California's customers to further reduce energy use. Nevertheless, it is also very clear from the results presented here that there remains a significant amount of demand response that can be achieved through TOU and dynamic pricing.

[4] Results from the EPRI study are summarized in Douglas Caves, Laurits Christensen and Joseph Herriges, *Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments.* Journal of Econometrics 16 (1984) 179-203, North-Holland.

The Brattle Group

Developing Critical-Peak Pricing Tariffs with the PRISM Software

Ahmad Faruqui

May 30, 2007

M1

What is the PRISM software?

- PRISM (pricing impact simulation model) can be used to develop the impact of different rate designs on utility load shapes
- It contains demand functions for peak and off-peak electricity consumption
- These functions are based on customer responses during California's three-year experiment (SPP) with 2,500 residential and small commercial and industrial customers
- The model can be calibrated for other service areas

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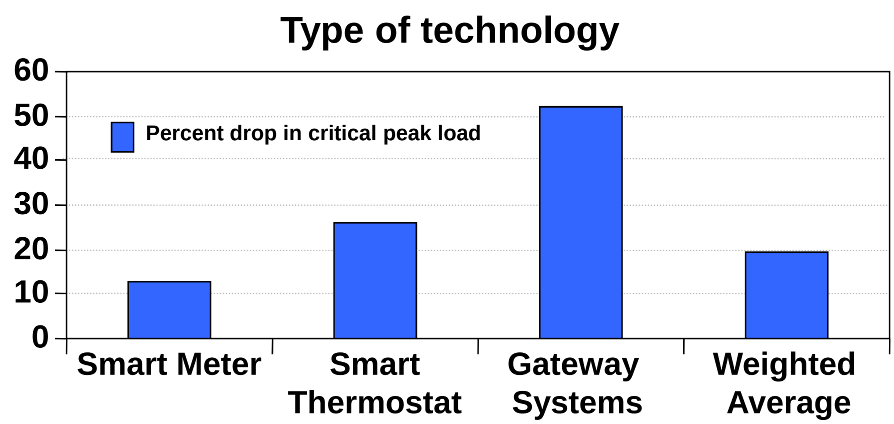
In the SPP, enabling technologies boosted the drop in critical peak loads



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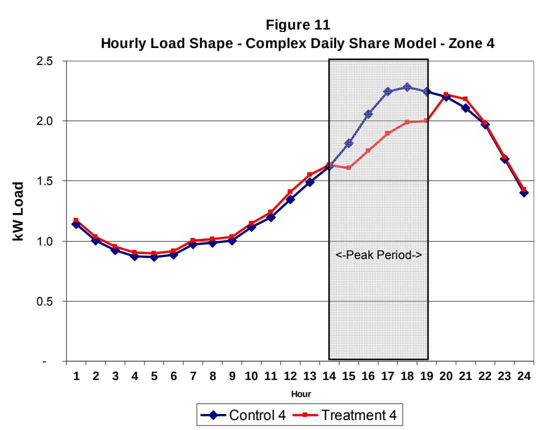
3

Dynamic prices were found to have a substantial impact in a hot climate



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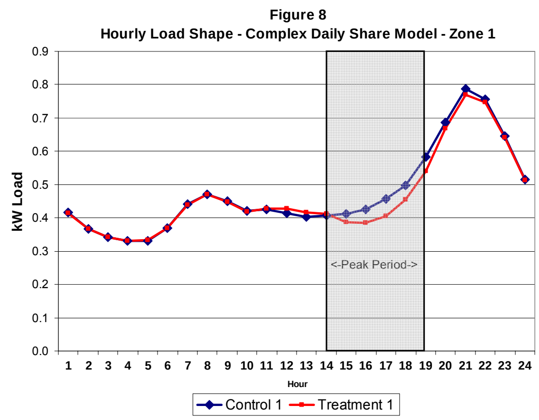
They had a modest but statistically significant impact even in a mild climate



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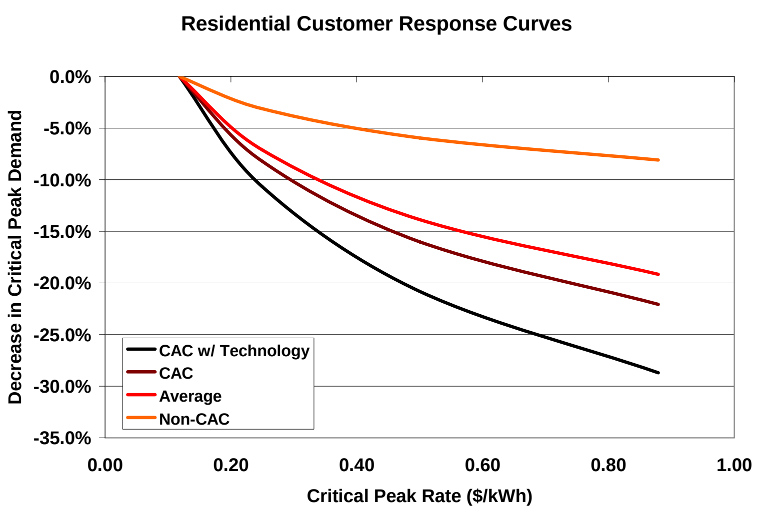
PRISM codifies the observed price responses and lets them vary by customer



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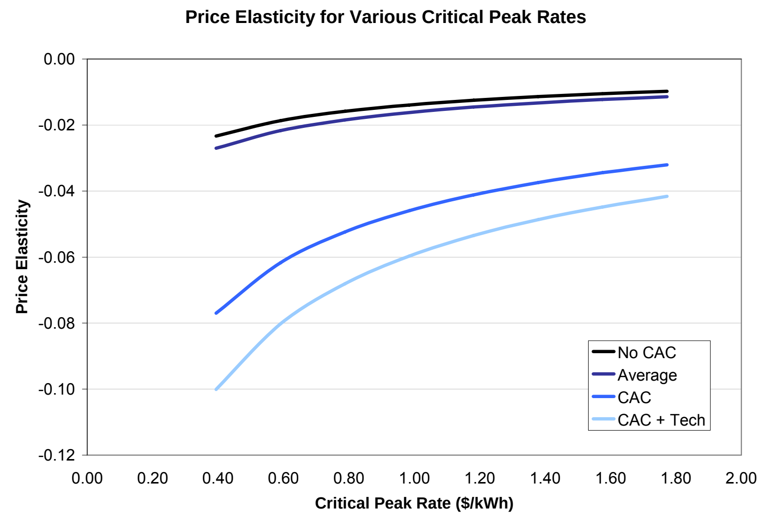
6

PRISM contains a variety of price elasticity functions



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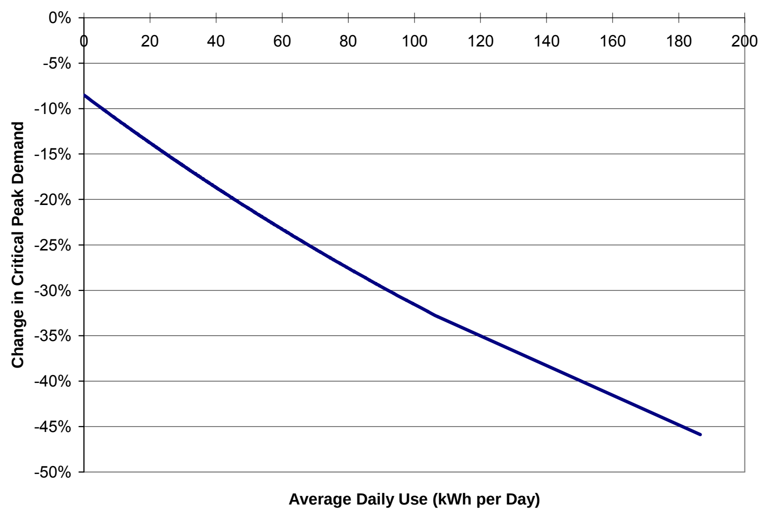
Within PRISM, as average daily use increases, so does the level of demand response



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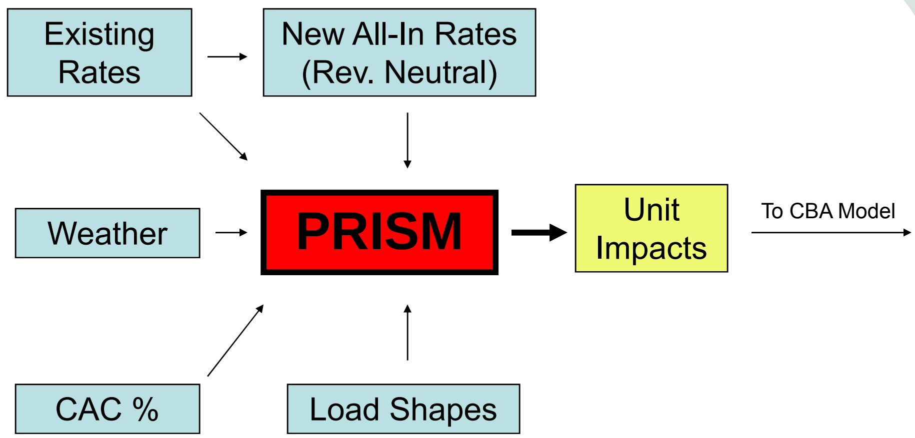
PRISM Flow Chart



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An illustration using PRISM

- The next several slides illustrate how PRISM can be used to assess demand response and quantify its financial benefits
- To give the illustration some realism, the data are mocked-up to resemble a mid-Atlantic utility

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First, the existing tariff has to be expressed as an all-in rate

To calculate the all-in rate:

1. The customer charge is divided by average monthly consumption and expressed as $/kWh
2. The customer charge rate and the distribution rate are added to the generation rates

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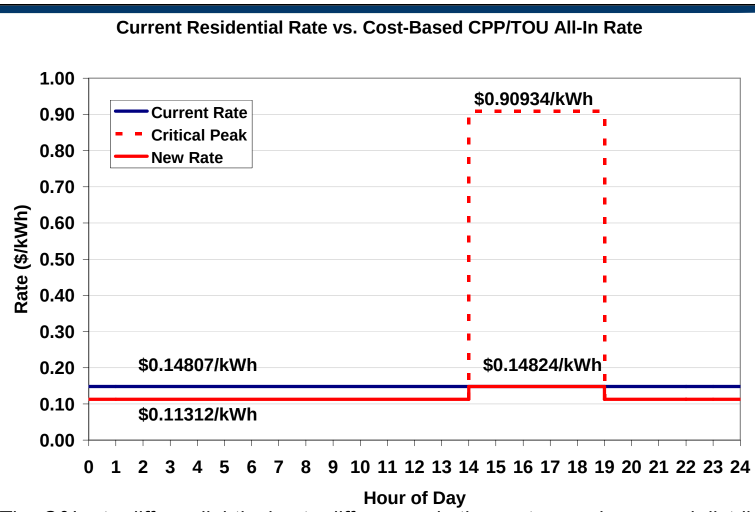
Then the CPP rate has to be developed, ensuring revenue neutrality and the creation of benefits for customers



Note: The C&I rate differs slightly due to differences in the customer charge and distribution charge, and to maintain revenue neutrality

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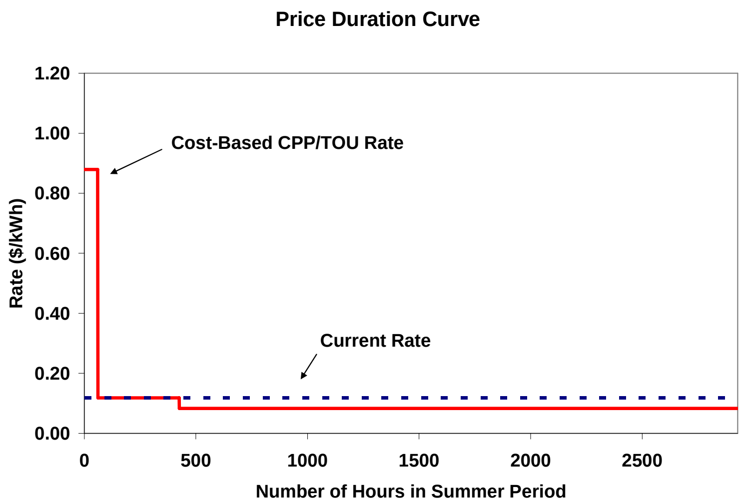
For a vast majority of summer hours, the customer will be at a rate that is lower than the current rate; this creates opportunity for bill savings



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Third, the CPP market needs to be defined

Two groups of customers

- Residential
- Small Commercial and Industrial

The residential market can be segmented into three customer types

- Central Air-Conditioning (CAC) with enabling technology (11% of existing customer base)
- CAC without enabling technology (67%)
- No CAC (22%)

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Additional assumptions about potential CPP market

Annual Growth Rates

- Residential: 1% per year
- Commercial: 2.6% per year

AMI Rollout Schedule

Year	Mid-Year % of Total Customer Base
2008	0%
2009	8%
2010	38%
2011	80%
2012	100%

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Results from PRISM

Results are presented on two levels

- Individual customer impacts
- System-wide impacts

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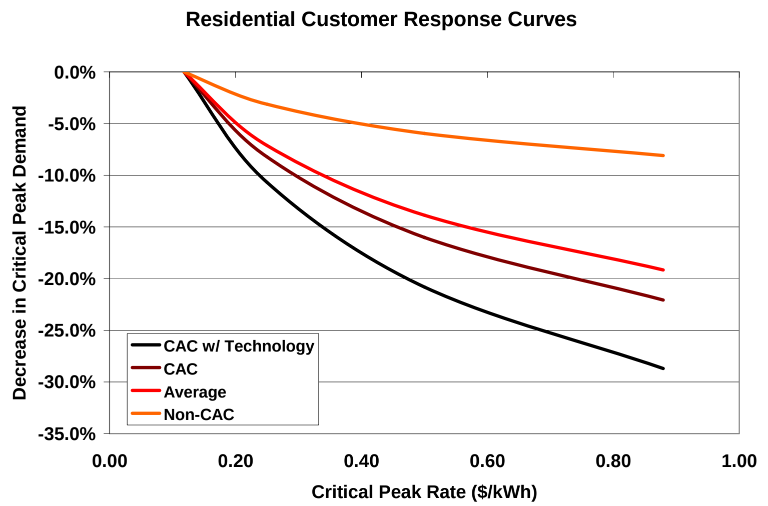
Residential customer response curves calibrated for the mid-Atlantic region climate



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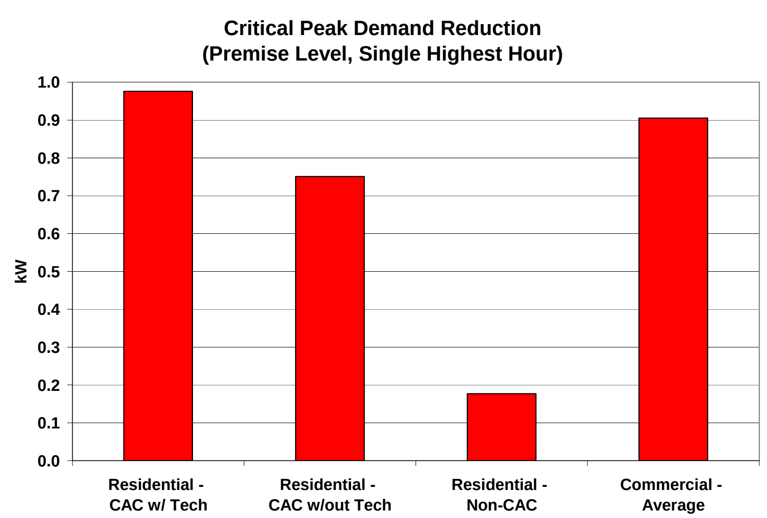
CPP can provide significant critical-peak demand response



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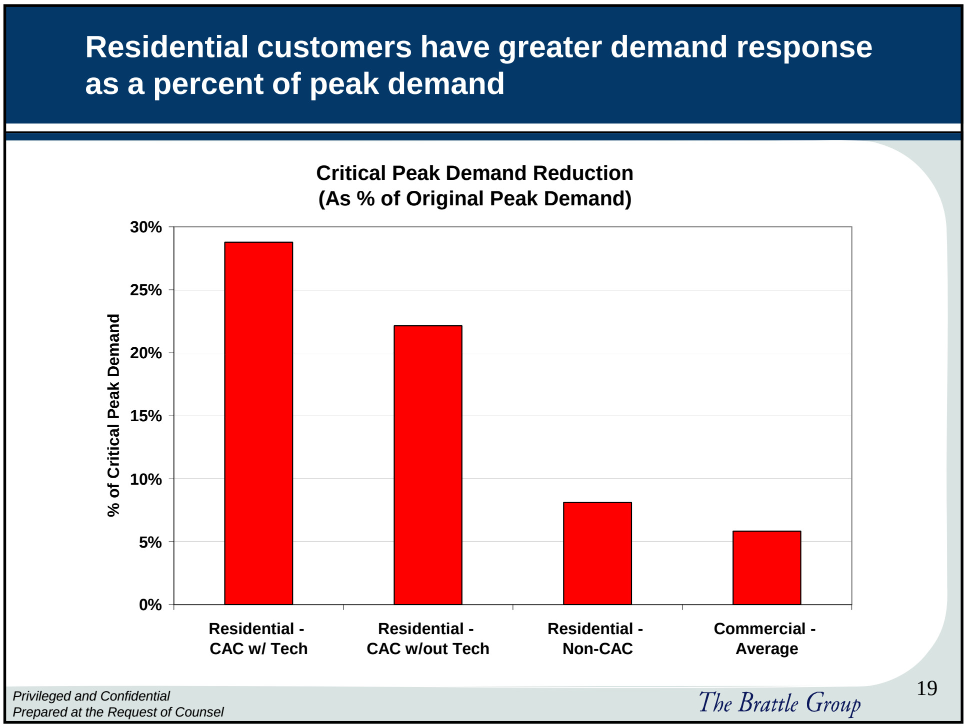
Residential customers have greater demand response as a percent of peak demand
Critical Peak Demand Reduction
(As % of Original Peak Demand)
% of Critical Peak Demand
30%
25%
20%
15%
10%
5%
0%
Residential - CAC w/ Tech
Residential - CAC w/out Tech
Residential - Non-CAC
Commercial - Average
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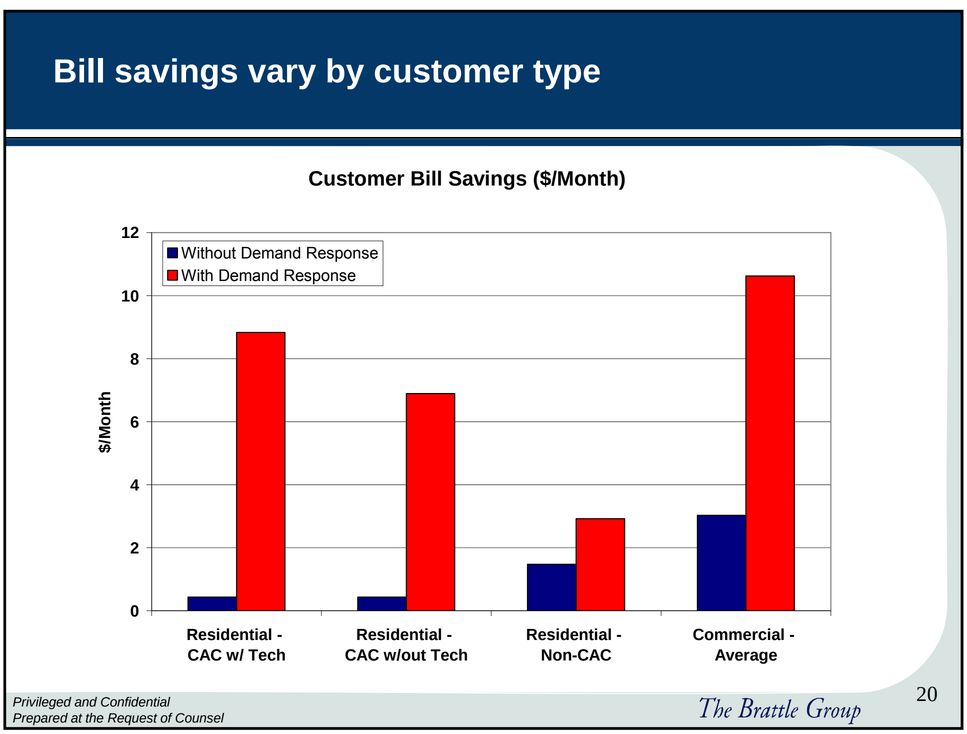
Bill savings vary by customer type
Customer Bill Savings ($/Month)
Without Demand Response
With Demand Response
$/Month
12
10
8
6
4
2
0
Residential - CAC w/ Tech
Residential - CAC w/out Tech
Residential - Non-CAC
Commercial - Average
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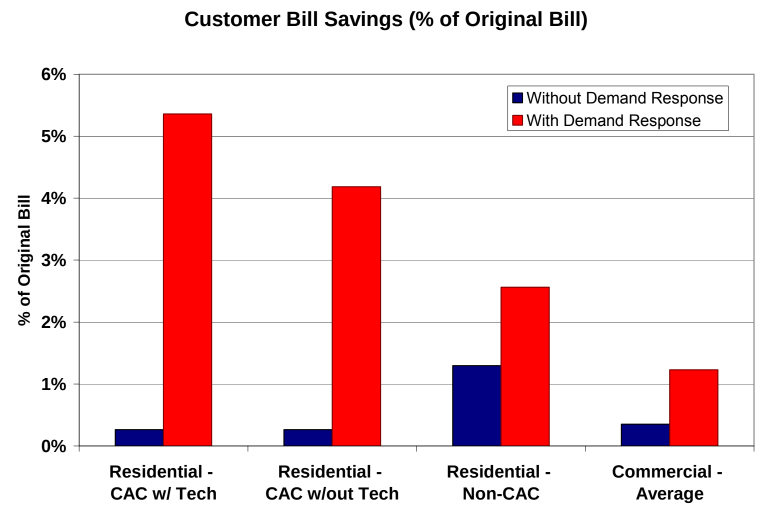
Residential customers experience greater savings as a percentage of the total bill than the average commercial customer



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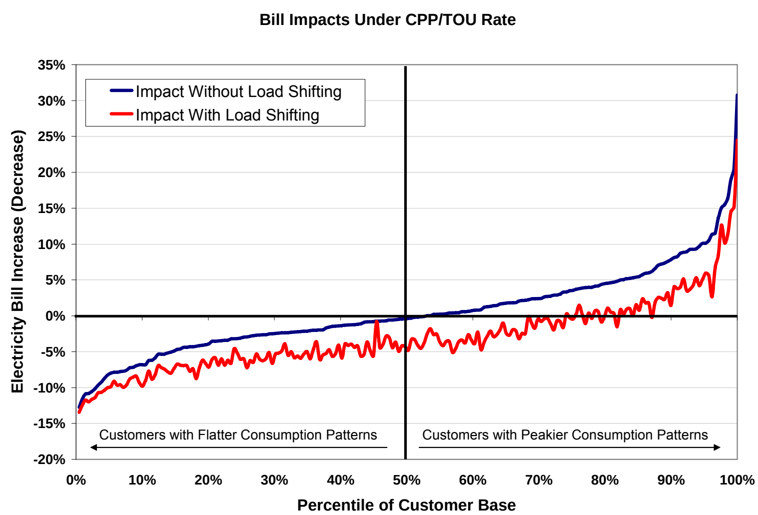
Without DR, the average customer's bill will remain unchanged; with DR, 80% to 90% of residential customers will experience bill savings



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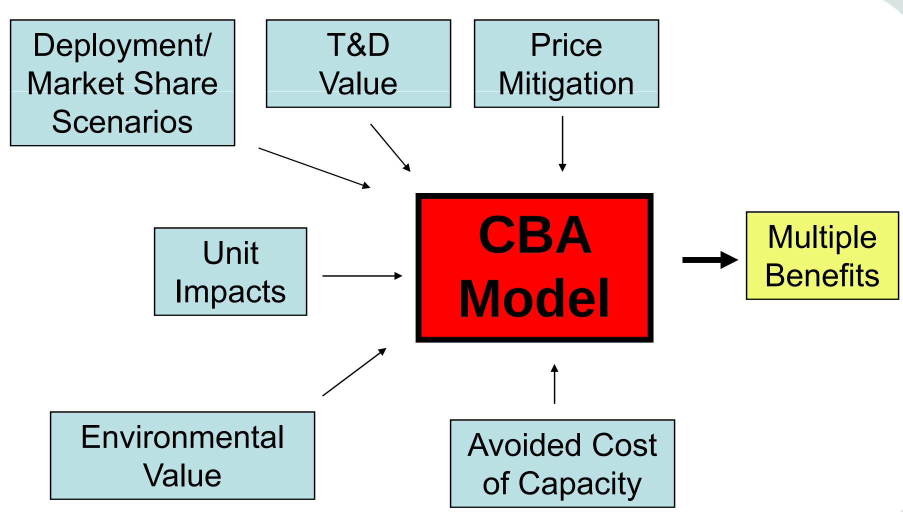
There are several ways of enhancing the customer appeal of CPP

- Providing an upfront, one-time cash incentive for participating customers
- Providing an ongoing, monthly cash payment akin to that given to the customers who are on load control
- Changing the rate design so it is revenue neutral for peakier-than-average customers
  - This will yield bill savings to a majority of customers even in the absence of load shifting
- Using a two-part rate where the first part is revenue neutral

The outputs of PRISM can drive a cost-benefit analysis (CBA) model



Once a baseline case has been evaluated, CBA allows for the rapid execution of sensitivities

Variable	Mode	Min	Max
Total Cost of Distribution System	$10.59/kW-year	Decreased 50%	Increased 50%
Total Cost of Transmission System	$17.50/kW-year	Decreased 50%	Increased 50%
CAC Saturation	78%	68%	83%
Price Elasticities	As calculated by PRISM	Decreased 50%	Increased 25%
Transmission carry cost	12%	7%	17%
Distribution carry cost	12%	7%	17%
Critical peak LMP (used in Price Mit. Calculation)	293	Decreased 25%	Increased 25%
Expected critical peak LMP decrease, given 1% decrease in critical peak demand	1%	0.5%	2.0%
Capacity price, beginning in 2011	$47.45/kW-year	$22.63/kW-year	58.00/kW-year

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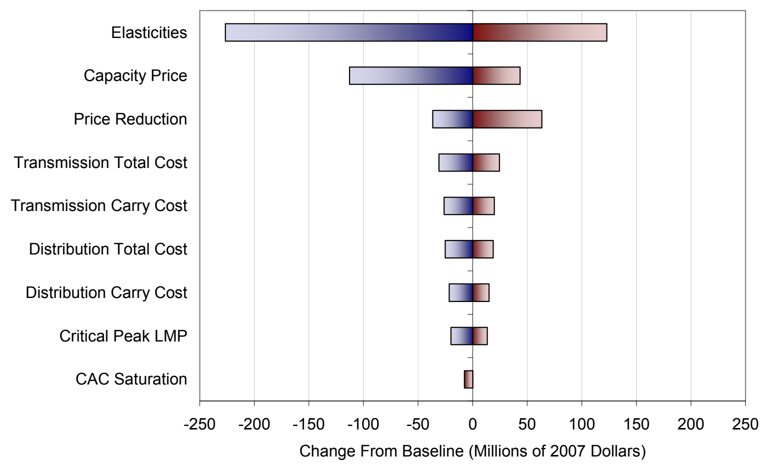
The sensitivity results can be laid out in a tornado diagram to highlight the most significant drivers

Impact of Sensitivities on Baseline Financial Value ($408 Million)



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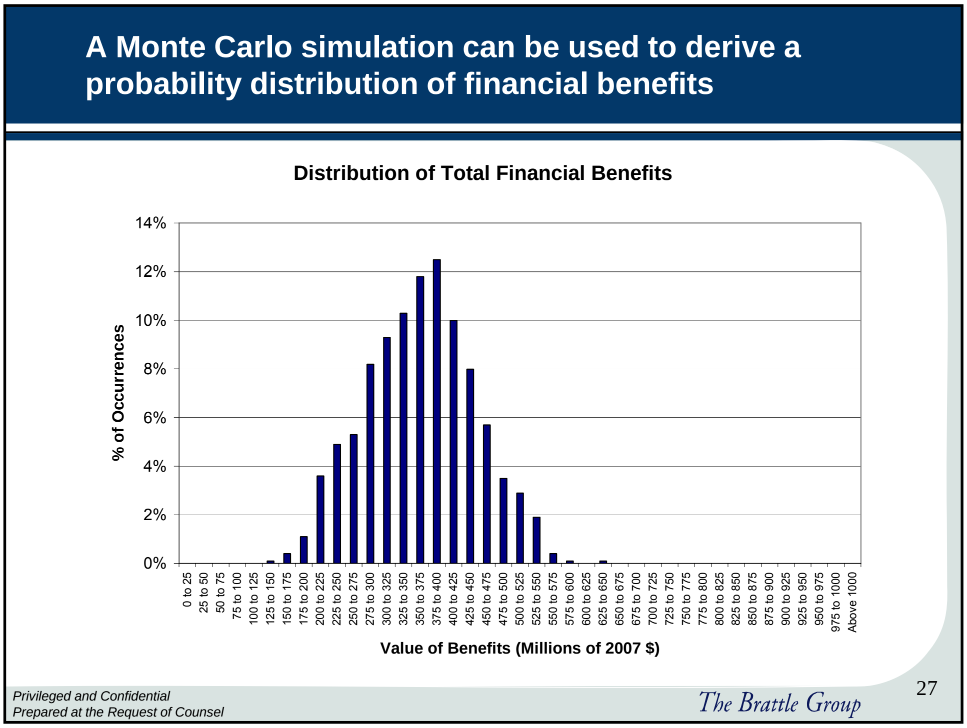
A Monte Carlo simulation can be used to derive a probability distribution of financial benefits
Distribution of Total Financial Benefits
% of Occurrences
Value of Benefits (Millions of 2007 $)
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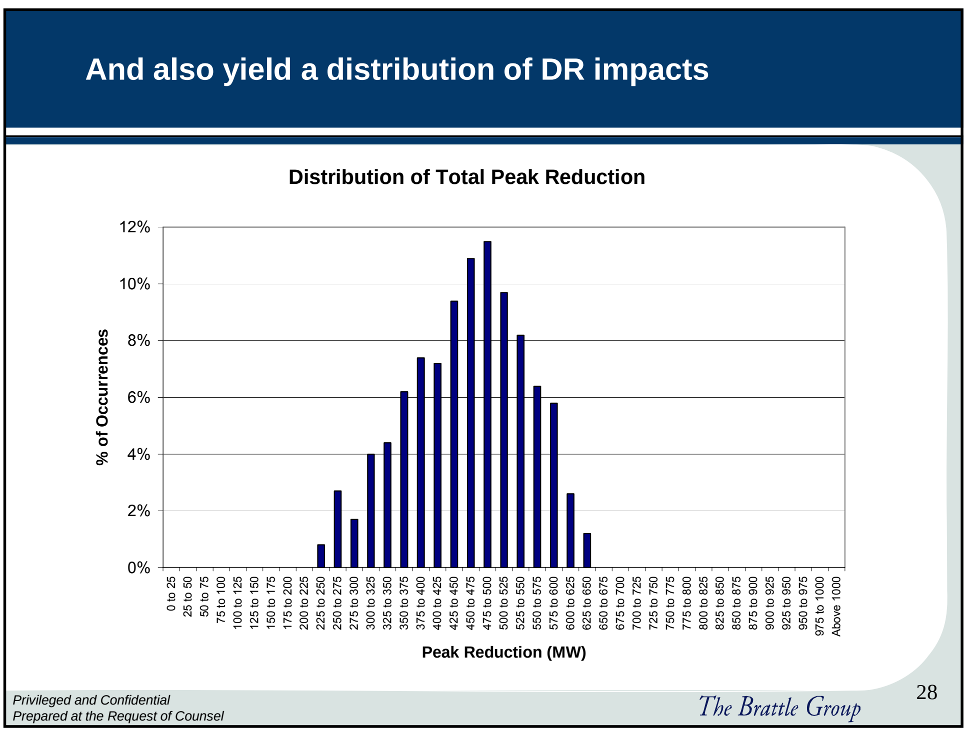
And also yield a distribution of DR impacts
Distribution of Total Peak Reduction
% of Occurrences
Peak Reduction (MW)
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APPENDIX E. COMPARISON OF RESULTS ACROSS DYNAMIC PRICING AND TIME-BASED RATE PILOT PROGRAMS

This appendix compares the results of several dynamic pricing pilots with each other and with those from the California statewide pricing pilot (SPP). In addition, to provide historical perspective, we provide a summary of results from 16 pricing pilots that were carried out under the auspices of the U.S. Department of Energy and its predecessor agency, the Federal Energy Administration, during the 1970s and 1980s. We use the term "dynamic pricing" to refer to pricing signals that are triggered based on actual wholesale market prices and not set in advance. (For example, a time-of-use (TOU) rate is not a dynamic price, because the peak period rate and timing are set in advance. Critical peak pricing (CPP) is dynamic, because while the rate may be set in advance, the critical days are called based on wholesale market conditions.)

Comparative results are presented for the following pilots and studies:

- Public Service Electric and Gas Co. (PSE&G) Residential Pilot Program, "Residential Time-of-Use with Critical Peak Pricing Pilot Program: Comparing Customer Response between Educate-Only and Technology Assisted Pilot Segments." 2007.
- Ontario Energy Board Smart Price Pilot, "Ontario Energy Board Smart Price Pilot." Final Report, 2007.
- Anaheim Critical Peak Pricing Experiment, "Residential Customer Response to Real-time Pricing: Anaheim Critical Peak Pricing Experiment." 2007.
- Idaho Residential Pilot Program, "2006 Analysis of the Residential Time-of-Day and Energy Watch Pilot Programs." Final Report, 2006.
- Energy Australia's Network Tariff Reform, "Network Price Reform." 2006.
- The Community Energy Cooperative's Energy-Smart Pricing Plan, "Evaluation of the 2005 Energy-Smart Pricing Plan – Final Report." 2006.
- AmerenUE Residential TOU Pilot Study, "AmerenUE Critical Peak Pricing Pilot." 2006.
- California Automated Demand Response System Pilot, "Automated Demand Response System Pilot – Final Report." 2006.
- California Statewide Pricing Pilot, "Impact Evaluation of the California Statewide Pricing Pilot." 2005.
- AmerenUE Residential TOU Pilot Study, "AmerenUE Residential TOU Pilot Study Load Research Analysis: First Look Results." 2004.
- The Gulf Power Select Program, "Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets: Appendix B." 2002.
- *Journal of Econometrics*, "Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments." 1984.

- *Energy*, "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing." 1983.

Our review of these dynamic pricing pilots reveals that dynamic prices are effective in reducing electricity usage. In general, CPP programs supported with enabling technologies result in the largest reductions in load. However, CPP programs alone (without an enabling technology) also achieve significant reductions in load. TOU programs without enabling technologies reduce load somewhat. However, when TOU programs are supported with enabling technologies, the average load reduction is larger. Based on the pilot results, the combination of dynamic prices with enabling technologies appears to be the most effective program design for reducing electricity usage during high-priced periods. A summary of the impacts associated with the pilots reviewed in this appendix are shown in Figure E-2 at the end of this appendix (as well as other summary exhibits).

PSE&G Residential Pilot Program

PSE&G offered a residential TOU/CPP pilot pricing program in New Jersey during 2006 and 2007.[1] The PSE&G pilot had two subprograms. Under the first subprogram, myPower Sense, participants were educated about the TOU tariff and notified of the CPP event on a day-ahead basis, and the program assessed the reduction in energy use when a CPP event was called. Under the second subprogram, myPower Connection, also designed to assess the reduction in energy use when a CPP event was called, participants were given a free thermostat that received price signals from PSE&G and adjusted their central air conditioning (CAC) based on previously programmed set points. A total of 1,286 customers participated in the pilot program: 450 in the control group, 459 in myPower Sense, and 377 in myPower Connection.

The TOU/CPP tariff included an off-peak rate, a base rate, an on-peak rate, and a critical peak rate for the summer months as shown in Table 1.

Table 1: TOU/CPP Rate Design: Summer Months (June to September 2006)

Period	Charge	Applicable
Base Price	$0.09/kW	All hours
Night Discount	-$0.05/kWh	10 p.m.-9 a.m. daily
On Peak Adder	$0.08/kW	1 p.m.-6 p.m. weekdays
Critical Peak	$0.69/kW	1 p.m.-6 p.m. weekdays when called (added to the base price when called.)

Source: PSEG-CPP Pilot, page 3.

TOU/CPP program impacts are summarized in Tables 2 and 3. The results show that a 100 percent increase in the peak to off-peak price ratio leads to an 8.5 percent decrease in the peak to off-peak demand ratio for myPower Sense customers (i.e., a substitution elasticity of 0.085). Similarly, myPower Connection customers reduced their peak to off-peak consumption ratio by 13.7 percent when the peak to off-peak price ratio increased by 100 percent. The results also show reductions of 1.1 and 2.1 kW per hour during CPP events for myPower Sense and myPower Connection, respectively. Achieved reductions in peak demand were reported to be 12 percent for myPower Sense and 18 percent for myPower Connection customers.

[1] PSE&G and Summit Blue Consulting, "Residential Time-of-Use with Critical Peak Pricing Pilot Program: Comparing Customer Response between Educate-Only and Technology Assisted Pilot Segments." 2007.

The higher reductions for myPower Connection customers are not surprising since these customers had an enabling technology (i.e., the smart thermostat), whereas the myPower Sense customers did not.

Table 2: Estimated Substitution Elasticity

Impact Estimate	Coefficient	90% Confidence Interval
myPower Sense	-0.085	-0.079 to -0.090
myPower Connection	-0.137	-0.131 to -0.142

Source: PSEG-CPP Pilot, page 4.

Table 3: Estimated CPP Event Impacts (average kW per hour)

Impact Estimate	Coefficient	90% Confidence Interval
myPower Sense	1.11	0.133 to 2.08
myPower Connection	2.12	1.09 to 3.17

Source: PSEG-CPP Pilot, page 4.

Ontario Energy Board Smart Price Pilot

The Ontario Energy Board operated the residential Ontario Energy Board Smart Price Pilot (OSPP) between August 2006 and March 2007.[2] The OSPP used a sample of Hydro Ottawa residential customers and tested the impacts from three different price structures:

- The existing Regulated Price Plan (RPP) TOU: The RPP TOU rates are shown in Table 4.
- RPP TOU rates with a CPP component (TOU CPP). The CPP was set at $0.30 per kWh based on the average of the 93 highest hourly Ontario electricity prices in the previous year. The RPP TOU off-peak price was decreased to $0.031 (from $0.035) per kWh to offset the increase in the critical peak price. The maximum number of critical day events was set at nine days; however, only seven CPP days were called during the pilot.
- RPP TOU rates with a critical peak rebate (TOU CPR): The CPR provided participants with a $0.30 per kWh rebate for each kWh of reduction from estimated baseline consumption. The CPR baseline consumption was defined as the average usage during the same hours over the participants' last five nonevent weekdays, increased by 25 percent.

[2] Ontario Energy Board, "Ontario Energy Board Smart Price Pilot Final Report." 2007.

Table 4: Regulated Price Plan (RPP) TOU Rate Design

Season	Time	Charge	Applicable
Summer (Aug 1- Oct 31)	Off-peak	$0.035/kWh	10 p.m.- 7 a.m. weekdays, all day on weekends and holidays.
Summer (Aug 1- Oct 31)	Mid-peak	$0.075/kWh	7 a.m.- 11 a.m. and 5 p.m.- 10 p.m. weekdays.
Summer (Aug 1- Oct 31)	On-peak	$0.105/kWh	11 a.m.- 5 p.m. weekdays.

Source: Ontario Energy Board Smart Price Pilot, page 2.

A total of 373 customers participated in the pilot: 124 in TOU-only, 124 in TOU-CPP, and 125 in TOU-CPR. The control group had 125 participants with installed smart meters but who continued to pay non-TOU rates.

The OSPP results show that:

- The load shift during the critical hours of the four summer CPP events ranged between 5.7 percent and 25.4 percent.[3]
- The load shift during the entire peak period of the four summer CPP events ranged between 2.4 percent and 11.9 percent.

Table 5 shows the shift in load during a CPP event as a percentage of the load in critical peak hours and of the entire peak period. It is important to note that the percentage reductions for the TOU-only customers are not significant at the 90 percent confidence level.

Table 5: Percentage Shift in Load During the Four Summer CPP Events Under Different RPP Structures

Period	TOU- only	TOU- CPP	TOU- CPR
Shift as % of critical peak hours	5.7%	25.4%	17.5%
Shift as % of all peak hours	2.4%	11.9%	8.5%

Source: Ontario Energy Board Smart Price Pilot, page 5.

This study also analyzed the total conservation impact during the full pilot period. The total reduction in electricity consumption due to program impacts is reported in Table 6. The average conservation impact across all customers was 6 percent.

[3] Under the OSPP, three to four hours of the peak period were defined as critical on a CPP day.

Table 6: Total Conservation Effect for the Full Pilot Duration (Treatment Compared to Control Group)

Program	% Reduction in Electricity
TOU-only	6.0
TOU-	4.7% (ns)
TOU-	7.4
Average Impact	6.0

Source: Ontario Energy Board Smart Price Pilot, page 5.
Note: ns refers to “not significant at the 90% confidence level.”

Anaheim Critical Peak Pricing Experiment

The City of Anaheim Public Utilities (APU) conducted a residential Critical Peak Pricing Experiment between June 2005 and October 2005.[4] A total of 123 customers participated in the experiment: 52 in the control group and 71 in the treatment group. The CPP rate rewarded participants with a rebate of $0.35 for each kWh reduction below the reference level peak-period consumption on non-CPP days (i.e., the baseline consumption). Table 7 presents the rate design.

Table 7: City of Anaheim CPP Rate Design

Group	Charge	Applicable
Control	Standard increasing-block residential tariff: $0.0675/kWh if consumption <=240kWh per month $0.1102/kWh if consumption >240kWh per month	All Hours
Treatment	Standard increasing-block residential tariff	All Hours except except peak hours (12 a.m. - 6 p.m.) on CPP days
Treatment	$0.35 rebate for each kWh reduction relative to their typical peak consumption on non-CPP days.	Peak hours (12 a.m. - 6 p.m.) on CPP days

Source: Anaheim Critical Peak Pricing Experiment, page 1-2.

The results show that:

- The treatment group used 12 percent less electricity on average during the peak hours of the CPP days than the control group.
- The reduction in consumption by customers in the treatment group was greater on higher temperature CPP days.

[4] Wolak, Frank A., “Residential Customer Response to Real-Time Pricing: Anaheim Critical Peak Pricing Experiment,” UCEI and Department of Economics, Stanford and NBER. 2007.

Idaho Residential Pilot Program[5]

Idaho Power initiated two residential pilot programs in the Emmett area of Idaho in the summers of 2005 and 2006: Time-of-day (TOD) and Energy Watch (EW).

Time-of-Day Pilot

The TOD pilot was designed as a conventional TOU program where the participants were charged different rates by time of the day as shown in Table 8. The TOD pilot included 85 treatment and 420 control group customers as of August 2006.

Table 8: Rate Design for the Time-of-Day Pilot

Period	Charge	Applicable
On-Peak	$0.083/kWh	Weekdays from 1pm to 9pm
Mid-Peak	$0.061/kWh	Weekdays from 7am to 1pm
Off-Peak	$0.045/kWh	Weekdays from 9pm to 7am and all hours on weekends and holidays

Source: 2006 Analysis of the Residential TOD and EW Pilot Programs, page 1.

As shown in Table 9, the results from the TOD pilot for summer 2006 show that, on average, the peak period percentage of total summer usage was the same for the treatment and control groups – about 22 percent. In fact, the percentage of usage during the mid-peak and off-peak periods was also the same between the two groups. This indicates that the TOD rates had no effect on shifting usage. However, given the very low ratio of on-peak to off-peak rates (about 1.84), this result is not so surprising. It indicates that a higher ratio of peak to off-peak rates is needed to induce customers to shift usage from peak to off-peak periods.

Table 9: Summer 2006 (June-August) Usage Under the TOD Pilot

	Average Use (kWh)		% of Total Summer Use			
Period	**Treatment**	**Control**	**Treatment**	**Control**	**Difference**	**T-stat**
On-Peak	800	763	22%	22%	-36.46	0.66
Mid-Peak	591	568	16%	16%	-22.43	0.52
Off-Peak	2307	2162	62%	62%	-145.78	0.99
Summer 06 Usage	3698	3493	100%	100%	-204.67	0.87

Source: 2006 Analysis of the Residential TOD and EW Pilot Programs, page 14.

[5] Idaho Power Co., "2006 Analysis of the Residential Time-of-Day and Energy Watch Pilot Programs: Final Report." 2006.

Energy Watch Pilot

The EW pilot was designed as a CPP pilot where the participants were notified of the CPP event on a day-ahead basis. A total of 10 EW days was called during summer 2006. EW was designed as follows:

- CPP hours from 5 p.m. to 9 p.m.
- Day-ahead notification
- CPP energy price of $0.20/kWh
- Non-CPP energy price of $0.054/kWh

The EW pilot included 68 treatment and 355 control group customers as of August 2006.

Table 10 shows the reduction in load (kW) on CPP days for each of the event days. Average hourly demand reduction ranged from 0.64 kW (on June 29) to 1.70 kW (on July 27). Average hourly load reduction for all 10 event days was 1.26 kW. The average total load reduction for a four-hour event was 5.03 kW.

Table 10: Energy Watch Day: Load Reductions (kW)

Hour Beginning	Hour Ending	29-Jun	11-Jul	14-Jul	18-Jul	19-Jul	25-Jul	27-Jul	3-Aug	9-Aug	15-Aug	Average
5pm	6pm	0.64	1.31	1.09	1.39	1.2	1.33	1.58	1.14	0.83	1.02	1.17
6pm	7pm	0.69	1.5	1.17	1.43	1.32	1.45	1.62	1.27	1.14	1.15	1.29
7pm	8pm	0.77	1.58	1.16	1.57	1.41	1.55	1.7	1.24	1.02	0.96	1.33
8pm	9pm	0.8	1.48	1.11	1.47	1.27	1.4	1.6	1.13	0.95	0.89	1.25
4-Hour Total		2.89	5.87	4.53	5.85	5.2	5.74	6.5	4.77	3.94	4.02	5.03
Average Hourly		0.72	1.47	1.13	1.46	1.3	1.43	1.62	1.19	0.99	1.01	1.26
Min Temp		68	65	65	61	62	75	68	59	62	67	65
Max Temp		85	100	98	94	98	99	104	92	85	92	95
Avg Temp		75	84	83	79	80	87	87	76	73	80	80

Source: 2006 Analysis of the Residential TOD and EW Pilot Programs, page 20.

Energy Australia's Network Tariff Reform

The Time of Use (TOU) pricing program is the largest demand management project by Energy Australia.[6] Recent price elasticity estimates from the TOU tariffs are presented in Table 11.

Table 11: TOU Price Elasticity Estimates

Type	Season	Peak Own Price Elasticity	Peak to Shoulder Cross Price Elasticity	Peak to Off-Peak Cross Price Elasticity
Residential	Summer 2006	-030 to -0.38	-0.07	-0.04
	Winter 2006	-0.47	-0.12	#N/A
Business (less than 40 MWh)	Summer 2006	-0.16 to -0.18 (ns)	-0.03	#N/A
	Winter 2006	-0.2 (ns)	#N/A	#N/A
Business (40 MWh to 160 MWh)	Summer 2006	-0.03 to -0.13 (ns)	#N/A	#N/A
	Winter 2006	-0.02 to -0.09 (ns)	#N/A	#N/A

Source: Network Price Reform, page 10.
Notes: ns refers to "not statistically significant."

The TOU results show that:

- Slight energy conservation effects result from residential consumption under TOU rates (compared to domestic consumption under the flat tariffs).
- Conservation effects are larger in winter than in summer for the residential customers.
- Business customer elasticities are not statistically robust due to large estimation errors stemming from heterogeneity. Therefore, they should be interpreted with caution.

Energy Australia started the Strategic Pricing Study in 2005 that included 1,300 voluntary customers (50 percent business, 50 percent residential). The study tested seasonal, dynamic, and information-only tariffs and involved the use of in-house displays and online access to data. Study participants received dynamic price signals through Short Message Service (SMS), telephone, email, or the display unit.

Preliminary results available from three Dynamic Peak Pricing (DPP) events show that:

- Residential customers reduced their dynamic peak consumption by roughly 24 percent for DPP high rates ($2+/kWh) and roughly 20 percent for DPP medium rates ($1+/kWh).
- Response to the 2nd DPP event was greater than that to the 1st DPP event. This may be attributed to the day-ahead notification under the 2nd DPP event (versus day-of notification under the 1st DPP event) and/or temperature differences.
- Response to the 2nd event was also greater than to the 3rd DPP event. This may be explained by lower temperatures on the 3rd DPP event that may have led to fewer discretionary appliances to turn off.

[6] Harry Colebourn, "Network Price Reform," presented at BCSE Energy Infrastructure & Sustainability Conference. December 2006.

The Community Energy Cooperative's Energy-Smart Pricing Plan

The Community Energy Cooperative (CEC) Energy-Smart Pricing Plan (ESPP), a residential real-time pricing (RTP) program, started in Illinois in 2003.[7] ESPP initially included 750 participants and expanded to nearly 1,500 customers in 2005. ESPP is the only residential RTP program that has been tested at any scale. ESPP has a focus on low technology and tests the hypothesis that major benefits may result from RTP without expensive technology adoption. The ESPP design included:

- Day-ahead announcement of the hourly electricity prices for the next day (i.e., customers were charged the day-ahead hourly prices)
- High-price day notification via phone or email when the price of electricity was over $0.10 per kWh
- A price limit hedge of $0.50 per kWh for participants, meaning that the maximum hourly price was set at $0.50 per kWh during their participation in the program
- Energy usage education for participants

The main goals of the pilot were to determine the price elasticity of demand and the overall impact on energy conservation. A regression-based analysis was conducted to estimate the price elasticity of demand for the summer months. Overall price elasticity was estimated to be -0.047. Automatic cycling of the central air conditioners using an enabling technology during high-price periods increased the overall price elasticity to -0.069. The largest response occurred on high-price notification days. For instance, on the day with the highest prices of summer 2005, participants reduced their peak hour consumption by 15 percent compared to what they would have consumed under the flat CEC residential rate. Price responsiveness varied over the course of a day. Price elasticities by time of day are presented in Table 12.

Table 12: Elasticity Estimates from ESPP

Time of the Day	Elasticity Estimate
Daytime (8 a.m. to 4 p.m.)	-0.02
Late afternoon/evening hours (4 p.m. to midnight)	-0.03
Daytime+ High-Price Notification	-0.02
Late Daytime/Evening+High-Price Notification	-0.05

Source: Evaluation of the 2005 Energy-Smart Pricing Plan-Final Report, page 11.

Results of the energy impact analysis indicate that ESPP participants consumed 35.2 kWh less per month during the summer months compared to what they would have consumed without the ESPP. These savings represent roughly 3 percent to 4 percent of the summer electricity usage. No statistically significant savings were found for the winter usage, which is not surprising since most high price days occur in the summer months in this area. Overall, ESPP resulted in a net decrease in monthly energy consumption.

[7] Summit Blue Consulting, "Evaluation of the 2005 Energy-Smart Pricing Plan-Final Report." 2006.

AmerenUE Critical Peak Pricing Pilot

First Year of the Pilot Program (2004)

AmerenUE in collaboration with Missouri Collaborative (formed by Office of Public Counsel (OPC), the Missouri Public Service Commission (MPSC), the Department of Natural Resources (DNR), and two industrial intervenor groups started a residential TOU pilot study in Missouri during spring 2004.[8] Program impacts associated with three different TOU programs were evaluated:

- TOU with peak, mid-peak, and off-peak rates
- TOU with a CPP component
- TOU with a CPP component and an enabling technology (smart thermostat)

Table 13 shows the rates evaluated in the pilot.

Table 13: Residential TOU Experiment Summer Rate Design

Program	Time	Charge	Applicable
TOU	Off Peak	$0.048/kWh	Weekday 10pm–10am, Weekends, Holidays
TOU	Mid Peak	$0.075/kWh	Weekdays 10am– 3pm and 7pm-10pm
TOU	Peak	$0.183/kWh	Weekday 3pm – 7pm
TOU-CPP	Off Peak	$0.048/kWh	Weekday 10pm–10am, Weekends, Holidays
TOU-CPP	Mid Peak	$0.075/kWh	Weekdays 10am– 3pm and 7pm-10pm
TOU-CPP	Peak	$0.168/kWh	Weekday 3pm – 7pm
TOU-CPP	CPP	$0.30/kWh	Weekday 3pm – 7pm, 10 times per summer

Source: AmerenUE Residential TOU Pilot Study Load Research Analysis: First Look Results, page 10.

Table 14 shows the number of participants in the treatment and control groups by type of rate.

Table 14: Experiment Sample Allocation

Treatment	Treatment Sample Size	Control Sample Size
TOU	88	89
TOU-CPP	85	89
TOU-CPP-Tech	77	117
Total	250	295

[8] Discussion of the 2004 results are based on RLW Analytics, “AmerenUE Residential TOU Pilot Study Load Research Analysis: First Look Results.” 2004.

The following results are based on the data compiled from the pilot between June 1, 2004, and September 30, 2004. The results show that:

- Participants in the TOU and TOU-CPP group do not shift a statistically significant amount of load from the on-peak to off-peak or mid-peak periods. As shown in Table 15, under both TOU and TOU-CPP programs, off-peak consumption increases and peak consumption decreases only slightly for the treatment group compared to the control group. However, none of these differences in consumption between the treatment and control groups is statistically significant.
- Participants in the TOU-CPP-Tech group do shift a statistically significant amount of load from the on-peak to off-peak or mid-peak periods. As shown in Table 15, the average treatment customer under this program increases off-peak consumption while decreasing mid-peak and peak consumption compared to the corresponding values for the control group. The difference is statistically significant.

Average consumption by participants during the pilot is provided in Tables 15 and 16.

Table 15: Average Participant Use by Program and Pricing Time – 2004

Program	Time	Control Group (kWh)	Treatment Group (kWh)	Difference	t-test	Pr> |t|	Statistical Significance of the Difference
TOU	Off Peak	33.63	34.87	-1.24	-0.71	0.479	Not Significant.
TOU	Mid Peak	23.59	22.78	0.81	0.71	0.476	Not Significant.
TOU	On Peak	13.81	13.36	0.45	0.67	0.505	Not Significant.
TOU	Seasonal	60.00	60.34	-0.34	-0.12	0.905	Not Significant.
TOU-CPP	Off Peak	35.84	38.36	-2.52	-1.19	0.235	Not Significant.
TOU-CPP	Mid Peak	24.11	24.54	-0.43	-0.34	0.733	Not Significant.
TOU-CPP	On Peak	13.82	13.29	0.54	0.73	0.466	Not Significant.
TOU-CPP	CPP	19.8	18.85	0.95	0.86	0.390	Not Significant.
TOU-CPP	Daily	62.87	65.3	-2.43	-0.72	0.473	Not Significant.
TOU-CPP-Tech	Off Peak	37.61	33.31	4.3	2.44	0.002	Significant.
TOU-CPP-Tech	Mid Peak	25.86	22.47	3.39	3	0.003	Significant.
TOU-CPP-Tech	On Peak	14.86	12.77	2.09	3.09	0.002	Significant.
TOU-CPP-Tech	CPP	21.39	15.48	5.92	6.5	0.000	Significant.
TOU-CPP-Tech	Daily	66.63	58.28	8.35	2.88	0.000	Significant.

Source: AmerenUE Residential TOU Pilot Study Load Research Analysis: First Look Results page 17, 22, 28.

Table 16: Average Usage on the Six CPP Event Days in Summer 2004

Program	Control Group (kWh)	Treatment Group (kWh)	Difference	% Difference	t-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	4.98	4.37	0.61	12%	2.09	0.038	Significant.
TOU-CPP-Tech	5.36	3.49	1.87	35%	8.09	0.000	Significant.

Source: AmerenUE Residential TOU Pilot Study Load Research Analysis: First Look Results page C.

Second Year of the Pilot Program (2005)

During the second year of the AmerenUE Critical Peak Pricing Pilot, the first year rate design described earlier remained in effect (see Table 13).[9] Table 17 summarizes the usage impact on eight CPP days in summer 2005.

Table 17: Average Usage on the Eight CPP Event Days in Summer 2005

Program	Control Group (kWh)	Treatment Group (kWh)	Difference	% Difference	t-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	5.56	4.84	0.72	13%	3.9	0.0001	Significant.
TOU-CPP-Tech	5.29	4.05	1.14	24%	6.05	0.0001	Significant.

Source: AmerenUE Critical Peak Pricing Pilot, page 10.

Table 18: Average Participant Use by Program and Pricing Time – 2005

Program	Jun 1- Aug 31 Period	Control Group (kWh)	Treatment Group (kWh)	Difference	t-test	Pr> |t|	Statistical Significance of the Difference
TOU-CPP	Off Peak	4495	4450	45	0.28	0.78	Not Significant.
TOU-CPP	Mid Peak	2054	2019	35	0.54	0.59	Not Significant.
TOU-CPP	On Peak	927	896	31	0.96	0.34	Not Significant.
TOU-CPP	CPP	252	219	33	3.92	0.00	Significant.
TOU-CPP-Tech	Off Peak	4147	4017	130	0.91	0.37	Not Significant.
TOU-CPP-Tech	Mid Peak	1934	1901	33	0.46	0.65	Not Significant.
TOU-CPP-Tech	On Peak	884	863	21	0.64	0.52	Not Significant.
TOU-CPP-Tech	CPP	240	182	58	5.99	0.00	Significant.

Source: AmerenUE Critical Peak Pricing Pilot, page 11.

The results from Table 17 and 18 show that:

- In 2005, the TOU-CPP rate induced customers to reduce usage during CPP periods.
- In 2005, the TOU-CPP-Tech rate induced customers to reduce usage during CPP periods.

Automated Demand Response System Pilot

California's Automated Demand Response System (ADRS) pilot program was initiated in 2004 and extended through 2005.[10] ADRS operated under a critical peak pricing tariff that was supported with a residential-scale, automated demand response technology. Participants in the pilot installed the GoodWatts system, an advanced home climate control system that allowed users to web-program their preferences for the control of home appliances. Under the CPP tariff, prices were higher during the peak period (2 p.m. to 7 p.m. on weekdays). All other hours, weekends and holidays were subject to the base rate. When the "super peak events" were called, peak price was three times higher than the regular peak price.

[9] Discussions of the 2005 results are based on Voytas, R., "AmerenUE Critical Peak Pricing Pilot," presented at Demand Response Resource Center Conference. 2006.

[10] Rocky Mountain Institute, "Automated Demand Response System Pilot." 2006.

The results from the pilot show that:

- Participants achieved substantial load reductions in both 2004 and 2005 compared to the control group.
- Load reductions on super peak event days were consistently about twice the load reductions during the peak periods on nonevent days.
- Technology appears to be the main driver of the load reductions, especially on super peak event days and for the high consumption customers.
- Part of the reduction is attributable to time-varying rates. However, the load reductions of the ADRS participants are consistently larger than those of the participants of other demand response programs without the technology.

Table 19 shows the impact estimates from the ADRS for high consumption customers.

Table 19: Peak Period Load Reductions for High Consumption Customers

	Event Days		Non-Event Days	
Program Year	**Average Reduction (kW)**	**% Reduction**	**Average Reduction (kW)**	**% Reduction**
2004	1.84	51%	0.86	32%
2005	1.42	43%	0.73	27%

Source: ADRS Study, Executive Summary, pages 6,11.

Impact Evaluation of the California Statewide Pricing Pilot

California's three investor-owned utilities, together with the state's two regulatory commissions, conducted the Statewide Pricing Pilot (SPP) that ran from July 2003 to December 2004 to test the impact of TOU pricing.[11] The SPP included about 2,500 participants consisting of residential and small-to-medium commercial and industrial (C&I) customers. SPP tested several rate structures:

- TOU-only rate where the peak price was twice the value of the off-peak price
- CPP rate where the peak price during the critical days was roughly five times greater than the off-peak price. The SPP tested two variations of the CPP rates.
    - The CPP-F rate had a fixed period of critical peak and day-ahead notification. CPP-F customers did not have an enabling technology.
    - The CPP-V rate had a variable length of peak duration during critical days and day-of notification. CPP-V customers had the choice of adopting an enabling technology.

The SPP utilized demand models to identify the impact of different rate and information structures on energy use. In addition to estimation of impacts associated with the average prices used in SPP, these demand models allowed estimation of the impacts from other potential prices. A demand system of two equations was estimated for each different rate structure. One of these equations estimates daily energy use while the

11 Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot." 2005.

other predicts the share of daily energy use by rate period. These equations are described in detail in Appendix H.

In this appendix, we review the residential customer impacts for the three rates: CPP-F, TOU, and CPP-V.

CPP-F Impacts

The average price for customers on the standard rate was about $0.13 per kWh. Under the CPP-F rate, the average peak-period price on critical days was roughly $0.59 per kWh, the peak price on non-critical days was $0.22 per kWh, and the average off-peak price was $0.09 per kWh.

- On critical days, statewide average reduction in peak-period energy use was estimated to be 13.1 percent. Impacts varied across climate zones from a low of -7.6 percent to a high of -15.8 percent.
- The average peak-period impact on critical days during the inner summer months (July- September) was estimated to be -14.4 percent while the same impact was -8.1 percent during the outer summer months (May, June, and October).
- On normal weekdays, the average impact was -4.7 percent, with a range across climate zones from -2.2 percent to -6.5 percent.
- No change in total energy use across the entire year was found based on the average SPP prices.
- The impact of different customer characteristics on energy use by rate period was also examined. CAC ownership and college education are the two customer characteristics that were associated with the largest reduction in energy use on critical days.

Table 20: Residential CPP-F Rate Impacts on Critical Days for Inner Summer Months (July, August, September) for All Customers

		Start Value (kWh/hr)	Impact (kWh/hr)	Estimate	t-stat	Impact (%)
		2003				
Rate Period	Peak	1.28	-0.163	#N/A	-20.94	-12.71
	Off-peak	0.8	0.021	#N/A	7.8	2.57
	Daily	0.9	-0.018	#N/A	-6.88	-1.95
Elasticity	Substitution	#N/A	#N/A	-0.086	-20.51	#N/A
	Daily	#N/A	#N/A	-0.032	-6.8	#N/A
		2004				
Rate Period	Peak	1.28	-0.178	#N/A	-18.49	-13.93
	Off-peak	0.8	0.01	#N/A	2.95	1.25
	Daily	0.9	-0.029	#N/A	-8.7	-3.24
Elasticity	Substitution	#N/A	#N/A	-0.087	-16.84	#N/A
	Daily	#N/A	#N/A	-0.054	-8.55	#N/A

Source: Impact Evaluation of the California Statewide Pricing Pilot, pages 51-52.
Notes:
[1] Estimations are based on average customer approach.
[2] All the numbers are based on average critical day weather in 2003/2004.

TOU Impacts

The average price for customers on the standard rate was about $0.13 per kWh. Under the TOU rate, the average peak-period price was roughly $0.22 per kWh and the average off-peak price was $ 0.09 per kWh.

- The reduction in peak period energy use during the inner summer months of 2003 was estimated to be -5.9 percent. However, this impact completely disappeared in 2004.
- Due to small sample problems in the estimation of TOU impacts, normal weekday elasticities from the CPP-F treatment may serve as better predictors of the impact of TOU rates on energy demand than the TOU price elasticity estimates.

Table 21: Residential TOU Rate Impacts for Inner Summer Months for All Customers

		Start Value (kWh/hr)	Impact (kWh/hr)	Estimate	t-stat	Impact (%)
		2003				
Rate Period	Peak	1.125	-0.063	#N/A	-11.08	-5.6
	Off-peak	0.744	0.011	#N/A	7.08	1.44
	Daily	0.823	-0.005	#N/A	-6.28	-0.57
	Weekend Daily	0.867	0.013	#N/A	4.46	1.45
Elasticity	Substitution	#N/A	#N/A	-0.099	-10.17	#N/A
	Daily	#N/A	#N/A	-0.117	-6.26	#N/A
	Weekend Daily	#N/A	#N/A	-0.066	-4.49	#N/A
		2004				
Rate Period	Peak	1.125	-0.007	#N/A	#N/A	-0.6
	Off-peak	0.744	-0.005	#N/A	#N/A	-0.65
	Daily	0.823	-0.005	#N/A	#N/A	-0.64
	Weekend Daily	0.867	0.005	#N/A	#N/A	0.61
Elasticity	Substitution	#N/A	#N/A	0.001	0.06	#N/A
	Daily	#N/A	#N/A	-0.132	-4.42	#N/A
	Weekend Daily	#N/A	#N/A	-0.028	-1.36	#N/A

Source: Impact Evaluation of the California Statewide Pricing Pilot, pages 92,95, and 96.
Notes:
[1] Estimations are based on average customer approach.

CPP-V Impacts

The average price for customers on the standard rate was about $0.14 per kWh. Under the CPP-V rate, the average peak-period price on critical days was roughly $0.65 per kWh and the average off-peak price was $0.10 per kWh. This rate schedule was tested on two different treatment groups. Track A customers were drawn from a population with energy use greater than 600 kWh per month. In this group, average income and CAC saturation was much higher than the general population. Track A customers were given a choice of installing an enabling technology and about two-thirds of them opted for the enabling technology. The Track C group was formed from customers who previously volunteered for a smart thermostat pilot. All Track C customers had CAC and smart thermostats. Hence, two-thirds of Track A customers and all Track C customers had enabling technologies.

- As shown in Table 22, Track A customers reduced their peak-period energy use on critical days by about 16 percent (about 25 percent higher than the CPP-F rate impact).
- Track C customers reduced their peak-period use on critical days by about 27 percent.

Comparing the CPP-F and the CPP-V results suggests that usage impacts are significantly larger with an enabling technology than without it.

Table 22: Residential CPP-V Rate Impacts for Summer for All Customers

		Start Value (kWh/hr)	Impact (kWh/hr)	Estimate	t-stat	Impact (%)
			Track A			
Rate Period	Peak	2.14	-0.3374	#N/A	-10.89	-15.76
	Off-peak	1.33	0.0445	#N/A	4.26	3.34
	Daily	1.46	-0.0187	#N/A	-1.71	-1.28
	Weekend Daily	1.3	0.0173	#N/A	2.72	1.33
Elasticity	Substitution	#N/A	#N/A	-0.111	-11.76	#N/A
	Daily	#N/A	#N/A	-0.027	-1.7	#N/A
	Weekend Daily	#N/A	#N/A	-0.043	-2.74	#N/A
			Track C			
Rate Period	Peak	2.33	-0.635	#N/A	-35.03	-27.23
	Off-peak	1.26	0.044	#N/A	3.19	3.52
	Daily	1.43	-0.059	#N/A	-9.85	-4.17
	Weekend Daily	1.34	0.016	#N/A	4.1	1.2
Elasticity	Substitution	#N/A	#N/A	-0.077	-10.61	#N/A
	Technology Impact-Substitution	#N/A	#N/A	-0.214	-24.04	#N/A
	Daily	#N/A	#N/A	-0.044	-3.49	#N/A
	Technology Impact-Daily	#N/A	#N/A	-0.019	-3.49	#N/A
	Weekend Daily	#N/A	#N/A	-0.041	-4.12	#N/A

Source: Impact Evaluation of the California Statewide Pricing Pilot, pages 105,106,109, and 110.
Notes:
[1] Estimations are based on average customer approach.
[2] Track A analysis was conducted for Summer 2004.
[3] Track C analysis pools summers 2003 and 2004 and estimates a single model.

The Gulf Power Select Program

In 2000, Gulf Power started a unique demand response program that provides customers with three different service options as described below. [12]

- The standard residential service (RS) pricing option, which involves a standard flat rate with no time-varying rates
- A conventional TOU pricing option (RST), which is a two-period TOU tariff
- The Residential Service Variable Price (RSVP) pricing option, which is a three-period CPP tariff

Under the RSVP option, the energy company provides the price signals and customers modify their usage patterns through a combination of the price signals and advanced metering and appliance control. Gulf Power markets the RSVP option under the GoodCents Select program and charges the participants a monthly participation fee. By the end of 2001, approximately 2,300 homes were served by the RSVP.

Table 23 shows the rates under the Gulf Power demand response program.

Table 23: Residential Tariffs for Summer Months

Program	Period	Charge	Applicable
RS	Base	$0.057/kWh	All Hours
RST	Off-peak	$0.027/kWh	12 a.m.-12 p.m. and 9 p.m.-12 a.m.
RST	Peak	$0.104/kWh	12 p.m.- 9 p.m.
RSVP	Off-peak	$0.035/kWh	12 a.m.-6 a.m. and 11 p.m.-12 a.m.
RSVP	Mid-peak	$0.046 /kWh	6 a.m.-11 a.m. and 8 p.m.-11 p.m.
RSVP	Peak	$0.093/kWh	11 a.m.-8 p.m.
RSVP	CPP	$0.29/kWh	When called.

Source: Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, Appendix B, page B-4.

Gulf Power reports the base coincident peak demand as 6.1 kW per household (hh). RSVP program performance results presented in Table 24 show that RSVP program participants reduce their demand by 2.75 kW per household during the critical peak period. This corresponds to a 41 percent reduction in energy usage during the critical peak period.

[12] Borenstein, S., M. Jaske, and A. Rosenfeld, "Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets." UCEI 2002.

Table 24: RSVP Program Performance by Period

Demand Reduction by Period	Performance
Average demand reduction (during peak period)	2.1 kW/hh
Average demand reduction (during critical peak period)	2.75 kW/hh
Average energy reduction (during peak period)	22%
Average energy reduction (during critical peak period)	41%

Source: Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, Appendix B, page B-8.

Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments

This study compiles data from five residential TOU experiments conducted by Carolina Power & Light, Connecticut Light and Power, Los Angeles Department of Water and Power, Southern California Edison, and Wisconsin Public Service, and estimates a consumer demand model for each of these with a goal to test the hypothesis that the substitution elasticities are identical across experiments.[13] Results of the study provide support for this hypothesis, and therefore provide a general model for estimating the residential response to TOU pricing. Since all five experiments used in this study featured some form of mandatory participation, results cannot be generalized to voluntary TOU settings. Selected findings from the study are the following:

- The price differential between peak and off-peak usage is the primary factor that determines the degree of customer response.
- The roles played by appliance holdings, customer characteristics, and climate are discernible, but they do not affect the magnitude of customer response nearly as much as the price differential.
- The elasticity of substitution varies with appliance holdings, customer characteristics, and climate, but, after controlling for these factors, it does not vary across areas.
- The elasticity of substitution between weekdays and weekends is smaller than that between peak and off-peak periods on weekdays.
- The results show that TOU rates lead to a reduction in the overall electricity usage.
- The typical customer in the typical climate has a substitution elasticity of -0.14. Substitution elasticity estimates for different customer characteristics and climate zones are shown in Table 25.
- Estimation of the results for the system peak days revealed no different response on these days compared to an average weekday.

[13] Caves, D. W., L. R. Christensen, and J. A. Herriges. 1984. “Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments.” Journal of Econometrics 26:179-203.

Table 25: Elasticity of Substitution Estimates for Summer Months (Peak to Off-Peak Usage)

Type of Climate	No Appliances	Typical Appliances	All Appliances	Typical Appliances except No AC Ownership	Typical Appliances except AC Ownership
Cool	0.09	0.12	0.16	0.13	0.11
Typical	0.07	0.14	0.21	0.11	0.16
Hot	0.05	0.15	0.25	0.1	0.21

Source: Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments, page 198.

The Residential Demand for Electricity by Time of Use: A Survey of 12 Experiments with Peak Load Pricing

This study reviews the empirical evidence from 12 of 15 residential pricing experiments that were funded and managed by DOE during late 1970s.[14] Based on the review of the pricing experiments:

- TOU pricing generally reduces peak energy consumption. Off-peak consumption stays the same or rises slightly.
- TOU pricing generally reduces daily energy consumption. Explicit load shifting from peak to off-peak is rarely observed.
- Customer response on average weekdays and system peak days differs only slightly.
- High usage customers are more responsive to TOU rates than are low usage customers.
- Peak and off-peak own-price elasticities range from 0 to -0.4. In a given experiment, elasticities vary across customers due to variation in total usage, appliance portfolio, and other factors. Across the experiments, these elasticities vary due to rate differences, variation in climate conditions, etc.
- There is little difference between elasticity estimates derived from single equations or demand systems.

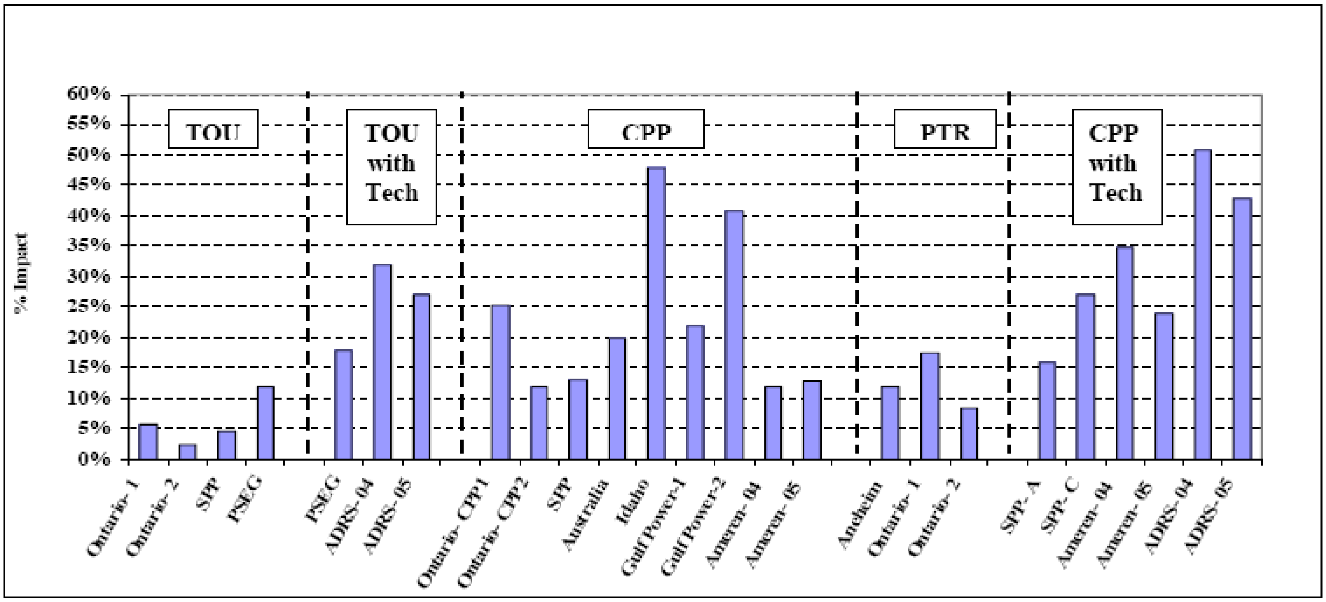
[14] Faruqui, A and J. R. Malko. 1983. "The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing." Energy Vol. 8: 781-795.

SUMMARY EXHIBITS

Table E-1: CAC Saturations from the Studies Reviewed in Appendix E

Pilot	Program	CAC Saturation
PSEG	CPP CPP w/ Tech	62% 100%
Ontario	TOU, CPP, and PTR	85%
SPP	TOU, CPP-F, and CPP-V	Average= 38 % CAC= 100 % No-CAC= 0 %

Figure E-2: Estimates of Percentage Reduction in Load (*) from the Studies Reviewed in Appendix E



Notes:
*Percentage reduction in load is defined relative to the different bases in different pilots. The following notes are intended to clarify these different definitions. TOU impacts are defined relative to the usage during peak hours unless otherwise noted. CPP impacts are defined relative to the usage during peak hours on CPP days unless otherwise is noted.

1- Ontario-1 refer to the percentage impacts during the critical hours that represent only 3-4 hours of the entire peak period on a CPP day. Ontario-2 refer to the percentage impacts of the programs during the entire peak period on a CPP day.
2- TOU impact from the SPP study uses the CPP-F treatment effect for normal weekdays as recommended by the study.
3- PSEG programs are represented in the TOU section even though they are CPP programs. The reason is that there were only two CPP events during the entire pilot period and more importantly, percentage impacts were only provided for the peak period on non-CPP days.
4- ADRS-04 and ADRS-05 refer to the 2004 and 2005 impacts. ADRS impacts on nonevent days are represented in the TOU with Tech section.
5- CPP impact for Idaho is derived from the information provided in the study. Average of kW consumption per hour during the CPP hours (for all 10 event days) is approximately 2.5 kW for a control group customer. This value is 1.3kW for a treatment group customer. Percentage impact from the CPP treatment is calculated as 48 percent.
6- Gulf Power-1 refers to the impact during peak hours on non-CPP days while Gulf Power-2 refers to the impact during CPP hours on CPP days.
7- Ameren-04 and Ameren-05 refer to the impacts respectively from the summers of 2004 and 2005.
8- SPP-A refers to the impacts from the CPP-V program on Track A customers. Two-thirds of Track A customers had some form of enabling technologies.
9- SPP-C refers to the impacts from the CPP-V program on Track C customers. All Track C customers had smart thermostats.

Table E-3: Summary of the Tariffs from the Studies Reviewed in Appendix E

Study	Control Group Tariff	Applicable Hours	Treatment Group Tariff	Applicable Hours
PSEG	$0.092/kWh	All hours	**CPP/** Night: $0.042/kWh	10 p.m.-9a.m. daily.
			CPP/ Peak: $0.172/kWh	1p.m.-6p.m. weekdays.
			CPP/ CPP: $0.78/kWh	1p.m.-6p.m. weekdays when called.
Ontario	$0.058/kWh	Usage<= 600 kWh per month	**TOU/** Off-peak: $0.035/kWh	10 p.m.- 7 a.m. weekdays, all day on weekends and holidays.
	$0.067/kWh	Usage>600 kWh per month	**TOU/** Mid-peak: $0.075/kWh	7 a.m.- 11 a.m. and 5 p.m.- 10 p.m. weekdays.
			TOU/ On-peak: $0.105/kWh	11 a.m.- 5 p.m. weekdays.
			CPP/ same as TOU except that there is a CPP component set at $0.30/kWh and off-peak price is decreased to $0.031/kWh	CPP days when called, otherwise same as TOU.
			PTR/ same as TOU with PTR at $0.30/kWh for each kWh reduction from the baseline	CPP days when called, otherwise same as TOU.
Anaheim	$0.0675/kWh	Usage<=240kWh per month	**PTR/** Control group tariff	All hours except 12a.m.- 6p.m. on CPP days.
	$0.1102/kWh	Usage>240kWh per month	**PTR/** $0.35/kWh rebate for each kWh reduction from baseline	12a.m.- 6p.m. on CPP days.
AmerenUE	#N/A	#N/A	**TOU/** Off-peak: $0.048/kWh	10p.m.–10a.m. weekdays, all day on weekends.
			TOU/ Mid-peak: $0.075/kWh	10a.m.– 3p.m. and 7p.m.-10p.m. weekdays.
			TOU/ On-peak: $0.1831/kWh	3p.m. – 7p.m. weekdays.
			CPP/ same as TOU except that there is a CPP component set at $0.30/kWh and peak price is decreased to $0.1675 /kWh	CPP days when called, otherwise same as TOU.
SPP	$0.13/kWh.	All hours	**TOU/** Off-peak: $0.09/kWh	12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends.
			TOU/ Peak: $0.22/kWh	2 p.m. to 7 p.m. weekdays.
			CPP-F/ Off-peak: $0.09/kWh	12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends.
			CPP-F/ Peak: $0.22/kWh	2 p.m. to 7 p.m. weekdays.
			CPP-F/ CPP: $0.59/kWh	2 p.m. to 7 p.m. weekdays when called.
			CPP-V/ Off-peak: $0.10/kWh	12a.m.- 2 p.m. and from 7 p.m. until 12a.m. weekdays, all day on weekends.
			CPP-V/ Peak: $0.22/kWh	2 p.m. to 7 p.m. weekdays.
			CPP-V/ CPP: $0.65 /kWh	2 or 5 hours during 2 p.m. to 7 p.m., weekdays when called.
Idaho	$0.054/kWh	Usage<= 300 kWh per month	**TOU/** Off-peak: $0.045/kWh	9p.m. to 7a.m. weekdays, all day on weekends.
	$0.061/kWh	Usage>300 kWh per month	**TOU/** Mid-peak: $0.061 /kWh	7a.m. to 1p.m. weekdays.
			TOU/ On-peak: $ 0.083/kWh	1p.m. to 9p.m. weekdays.
			CPP/ Non-CPP hours: $0.054/kWh	All hours except CPP hours.
			CPP/ CPP: $0.20/kWh	5 p.m. to 9 p.m. on CPP days.
Gulf Power	$0.057/kWh	All hours	**RST/** Off-peak: $0.027/kWh	12 a.m.-12p.m. and 9p.m.-12a.m.
			RST/ Peak: $0.104/kWh	12p.m.- 9p.m.
			RSVP/ Off-peak: $0.035/kWh	12a.m.-6a.m. and 11p.m.-12a.m.
			RSVP/ Mid-peak: $0.046 /kWh	6a.m.-11a.m. and 8p.m.-11p.m.
			RSVP/ Peak: $0.093/kWh	11a.m.-8p.m.
			RSVP/ CPP: $0.29/kWh	Assigned hours on CPP days.

Table E-4: Summary of the Elasticities from the Studies Reviewed in Appendix E

Study	Program	Substitution Elasticity	Own Price Elasticity	Cross Price Elasticity
PSEG	CPP	-0.085	#N/A	#N/A
	CPP w/ Tech.	-0.137	#N/A	#N/A
Chicago	RTP	#N/A	-0.047 (overall)	#N/A
	RTP	#N/A	-0.069 (overall with AC cycling)	#N/A
	RTP	#N/A	-0.015 (daytime)	#N/A
	RTP	#N/A	-0.026 (late daytime/evening)	#N/A
	RTP	#N/A	-0.02 (daytime+high price notification)	#N/A
	RTP	#N/A	-0.048 (late daytime/evening+high price notification)	#N/A
Australia	TOU	#N/A	-0.30 to -0.38	-0.07 (peak to shoulder)
	TOU	#N/A	#N/A	-0.04 (peak to off-peak)
SPP	CPP-F	-0.087	-0.054 (daily)	#N/A
	CPP-V/ Track A	-0.111	-0.027 (daily)	#N/A
	CPP-V/ Track A	#N/A	-0.043 (weekend daily)	#N/A
	CPP-V/ Track C	-0.154 (*)	-0.044 (daily)	#N/A
	CPP-V/ Track C	#N/A	-0.041 (weekend daily)	#N/A
Faruqui &Malko (1983)	TOU	#N/A	0 to -0.4 (range for peak and off-peak)	#N/A
Caves et al. (1984)	TOU	-0.09 (cool+no appliances)	#N/A	#N/A
	TOU	-0.07 (typical+no appliances)	#N/A	#N/A
	TOU	-0.05 (hot+no appliances)	#N/A	#N/A
	TOU	-0.12 (cool+typical appliances)	#N/A	#N/A
	TOU	-0.14 (typical+typical appliances)	#N/A	#N/A
	TOU	-0.15 (hot+typical appliances)	#N/A	#N/A
	TOU	-0.16 (cool+all appliances)	#N/A	#N/A
	TOU	-0.21 (typical+all appliances)	#N/A	#N/A
	TOU	-0.25 (hot+all appliances)	#N/A	#N/A

Note:
(*) Elasticity of substitution for CPP-Track C customers is estimated to be -0.077 and excludes the impact of technology (-0.214).
We calculated substitution elasticity including the impact of technology as -0.154 through simulation.

APPENDIX E. BIBLIOGRAPHY

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APPENDIX F: IMPACT OF DYNAMIC PRICING ON LOW-INCOME CUSTOMERS

Dynamic pricing offers electric customers lower prices during most hours of the summer while raising prices significantly for a small percentage of hours when system conditions are critical (typically 2 to 3 percent of all summer hours). The primary attraction of dynamic rates such as critical peak pricing (CPP) or real-time pricing (RTP) is that these rates provide direct incentives to reduce electricity usage when the electrical system is most stressed because they reflect daily peak marginal costs.[1,2]

Some have expressed concern that dynamic pricing may adversely impact low-income customers. In jurisdictions where dynamic prices are under consideration, many utilities are currently pilot testing some type of CPP rate.[3] In this appendix, we summarize the impact of CPP on low-income customers based on empirical results from the California Statewide Pricing Pilot (SPP) of 2003-04.[4] The results show that there is no statistically significant difference in bill-savings across income groups. This means that high-income customers on a dynamic rate do not benefit more than low-income customers, on average. However, taking usage into account, low-income customers in very high usage groups may find it difficult to “save” under a CPP rate. From a policy perspective, alternative dynamic pricing options should be considered for this group of high-usage, low-income customers. Depending on the definition of high usage, this represents about 2.2 percent to 5.7 percent of all households in the U.S. or 4.2 percent to 11 percent of all low-income households. (See Tables F-1 and F-2).[5] One obvious solution is to offer a peak-time rebate (PTR) rather than CPP to this specific group of high-usage, low-income customers. In addition, low-income customers in the low-usage group could be offered a choice between PTR and CPP. In the District of Columbia, as part of its dynamic pricing pilot program, Pepco is currently offering a PTR (also called a critical peak rebate or CPR) to customers that are currently on the Residential Aid Discount (RAD) program.[6]

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1 Direct load control (DLC) programs are in widespread use today. DLC is problematic in that it offers a fixed financial incentive for an unmeasured load reduction and payments to participants can exceed system benefits. TOU pricing is another strategy for peak reduction. However, under TOU, there is no additional incentive to reduce load when the system is most stressed. Both CPP and RTP correct these shortcomings.

2 Herter, K., “Residential implementation of critical-peak pricing of electricity.” Energy Policy 35 (2007). pp: 2121-2130

3 Although real time pricing (RTP) is available for residential customers in Illinois, policy makers in most states currently consider RTP to be infeasible and are examining alternative dynamic pricing structures such as CPP and peak-time rebate (PTR).

4 Charles River Associates, “Impact Evaluation of the California Statewide Pricing Pilot,” March 2005.

5 Based on the Residential Energy Consumption Survey (RECS) 2001, the percentage of all households that are low income (defined as less than $40,000) and high usage is about 2.2 percent (defined as 200 percent of average annual kWh) or 5.7 percent (defined as 150 percent of average annual kWh). Based on RECS, average annual usage is 10,654 kWh (833 kWh monthly). Using these definitions of low income and high usage, the percentage of <u>low income customers that are high usage is 4.2 percent (using 200 percent of average annual kWh as the definition of high usage) or 11 percent (using 150 percent of average annual kWh as the definition of high usage)</u>. Note that 150 percent of average usage is approximately equal to the top quintile of usage in the U.S. The $40,000 cutoff for low income is similar to the one used in the CA SPP and is somewhat higher than most definitions of low income.

6 The Pepco RAD program offers discounts on electricity to low-income customers. For details on the Pepco program, see Smart Meter Pilot Program, Inc., “PowerCentsDC™ Project: Program Description,” April 9, 2007. In general, under a PTR, customers remain on the static rate but receive a rebate for lowering their usage during critical peak hours below what they would have consumed normally during those hours.

Table F-1: Low Income and High Usage (Using 150 Percent of Average Usage)

Low Income and High Usage Breakdown	
High Usage Defined as 150% Greater then Average	
Average Annual Usage (kWh)	10,654
Low Usage: 50% of Average (kWh)	5,327
High Usage: 150% of Average (kWh)	15,981
Low Income Definition	< $40,000
Total Households	106,989,274
HH Under $40,000/Over 150%	**6,074,485**
HH % Under 40/Over 150%	**5.68%**
Total HH With Low Income	55,492,016
Total HH with High Usage	20,028,174
% Total HH with High Usage	18.72%
% Low Income with High Usage	**10.95%**

Table F-2: Low Income and High Usage (Using 200 Percent of Average Usage)

Low Income and High Usage Breakdown	
High Usage Defined as 200% Greater then Average	
Average Annual Usage (kWh)	10,654
Low Usage: 50% of Average (kWh)	5,327
High Usage: 200% of Average (kWh)	21,308
Low Income Definition	< $40,000
Total Households	106,989,274
HH Under $40,000/Over 200%	**2,301,283**
HH % Under 40/Over 200%	**2.15%**
Total HH With Low Income	55,492,016
Total HH with High Usage	9,471,143
% Total HH with High Usage	8.85%
% Low Income with High Usage	**4.15%**

The California SPP consisted of three tracks: Track A, which included a statistically representative sample of customers; Track B, which focused on low-income customers in areas of San Francisco (located in close proximity to a power plant); and Track C, which focused on customers in San Diego that had smart thermostats.[7] Track A comprised four climate zones while Tracks B and C focused on single climate zones.

In this appendix, we examine the impact of dynamic pricing on low-income customers based on the results of the SPP. First, we summarize the results of a recent study that focused on the final three-month period of the SPP: July 1 to September 30, 2004.[8] These results are indicative of an established program. Second, we provide results for Track B customers only, which represent low-income customers over the entire SPP (15

[7] For the Track B evaluation, see San Francisco Community Power in cooperation with M. Cubed and Charles River Associates, "Statewide Pricing Pilot Track B: Evaluation of Community-Based Enhancement Treatment," Draft Final Report, March 29, 2005.

[8] Herter, K., "Residential implementation of critical-peak pricing of electricity." Energy Policy 35 (2007). pp: 2121-2130

months from July 2003- September 2004). Finally, we provide results for Track A customers, which represent the general population of California over the 15-month period. Using Track A, we compare low-income customers to other customers in the same track. As shown below, each of these comparisons shows that low-income customers do respond to dynamic prices. However, as pointed out earlier, there may be very specific groups of customers that should be targeted for PTR rather than CPP.

SPP Results: Income and Usage Group Differences

Some groups have advocated targeting dynamic pricing to the large users of electricity in the residential sector while others have questioned whether dynamic pricing should be offered to low-income customers. Whether these suggestions are sensible depends on the responses of different usage and income groups to dynamic prices and the resulting bill impacts. It is important to recognize that a small percentage of low-income customers are also high-usage customers (about 4.2 percent to 11 percent of low-income customers are high usage depending on the definition of high usage as describe earlier). Based on a sample of 457 customers from the SPP, Herter analyzed the demand responsiveness of low-use (less than or equal to 600 kWh per month) vs. high-use customers (greater than 600 kWh) by three income groups.[9] She found that high-usage customers reduce usage during CPP events while low-usage customers do not show a statistically significant reduction in usage. She also found that, among high users, low- and middle-income customers respond as much as (or more than) high-income customers. Among low users, there were no significant differences across the three income groups.

Herter also examined the bill impacts by usage and income group. Her findings show that, on average, customers save on the CPP rate; low-usage customers save an average of 4 percent on their electricity bills whereas high usage customers save an average of 1.7 percent; across income levels, bill savings are not statistically different. **These findings indicate that targeting dynamic pricing only to high-usage customers would make little sense.**

A second finding of interest is that high-usage customers with incomes under $50,000 have insignificant bill savings. An examination of the distribution of savings for these customers finds that while some customers did save, others in this group were likely to experience bill increases. This finding suggests that low-income customers with high usage should perhaps be targeted and offered an alternative to CPP such as PTR (representing about 4 percent of low-income customers). **However, low-usage customers are likely to experience bill savings regardless of income group. Therefore, it would make little sense to exclude low-income customers with low usage from dynamic pricing.**[10]

SPP Track B (Low-income) Customer Analysis

The objective of Track B was to examine whether residential customers would be more likely to shift their electricity use off-peak if: (1) they lived close to an electric generating facility, (2) they received information about the connection between electricity generation, especially during the critical peak periods, and associated polluting air emissions, and (3) this information was delivered by a community-based group. Two groups within Track B received community-based information/education and CPP-F price signals, and the third group received only the CPP-F price signals.[11]

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9 Note that Herter simply divides usage groups into above and below average. Herter defined low income as $0-$24,999; middle income: $25,000-$49,999; high income: $50,000 and higher.

10 See Herter (2007) for the detailed results.

11 The SPP tested several different rates including two CPP rates and a traditional TOU rate. The CPP-F rate featured a fixed peak period on both critical and non-critical days between 2 p.m. and 7 p.m. weekdays and day-ahead customer

Track B customers were selected from San Francisco's Bayview, Hunters Point, and Potrero neighborhoods. A control group was selected from Richmond, CA. The control group received price signals but not the enhanced information. The city of Richmond was selected based on its comparability to San Francisco in terms of: climate, energy consumption patterns, demographic characteristics, and environmental hazards and associated environmentally focused community activism.

Demographically, Bayview/Hunters Point and Richmond are similar in their demographics and low median income relative to the San Francisco metropolitan area. The Bayview/Hunters Point population has a median household income of about $44,000. The Richmond population has a median income of about $39,000. This is in contrast to the San Francisco metropolitan area with a median income of about $62,000.

In general, Track B customers showed an ability to shift their usage despite low air conditioning saturation rates and low need for air conditioning given the climate. Examining only Track B low-income customers, Table F-3 shows that peak period consumption decreased on critical peak days. For customers who received information but no price signal, the average daily percentage decrease in consumption during critical peak hours was about 1 percent. For customers who received both information and a price signal, the average daily percentage decrease in consumption during critical peak hours was about 2.6 percent. These results demonstrate that low-income customers do respond to both information/education and price signals.

Table F-3: Change in Critical Peak Period Consumption of Track B (Low-income) Customers in SPP[12]

Impact of information only vs. price and information on consumption	Average Change in Critical Peak Period Consumption (Summer 2003 & 2004)
Track B customers: Information Only	-1.15%
Track B customers: Price & Information	-2.60%

SPP Track A (General Population) Customer Comparison

The primary objective of Track A was to estimate the average impact of different time-varying rates on energy use for each rate period. Track A customers were selected to represent California's general population. These customers were split into treatment groups with several different rate structures that included a traditional TOU rate, a variable critical peak pricing (CPP-V) rate, and a fixed critical peak pricing (CPP-F) rate. In addition to getting a different rate or electricity price, customers received educational materials about the environmental and economic benefits of shifting their electricity usage from peak to off-peak periods.

notification. The CPP-V rate featured a variable length peak period on critical days, which could be called on the day of the critical event. On non-critical days, under both the CPP-F and the CPP-V rates, a TOU rate was in effect. The SPP did not test the PTR.

12 Average results from Summer 2003 and Summer 2004 in Table 4-2 in San Francisco Community Power in cooperation with M. Cubed and Charles River Associates, "Statewide Pricing Pilot Track B: Evaluation of Community-Based Enhancement Treatment," Draft Final Report, March 29, 2005

Track A of the SPP provides additional evidence that low-income customers are price responsive. This track covered all four climate zones in the state. Results are available for two categories of low-income customers. First we compare customers with low income. Second, we compare customers on a low-income rate (CARE) that received a 20 percent discount on the electric bill versus non-CARE customers. About 20 percent of residential customers in California are on the CARE rate.

As shown in Table F-4, although high-income households (defined as greater than $100,000) are somewhat more price-responsive than low-income households (defined as less than $40,000), low-income customers do exhibit demand response. Low-income customers dropped their load during critical peak hours by 11 percent whereas high-income customers dropped their load by 16 percent.

Table F-4 also shows that customers who did not receive the CARE discount were much more price responsive (dropping their load by about 16 percent) than those who did receive the CARE discount (dropping their load by only 3 percent).[13] Finally, the price responsiveness of all customers was about 13 percent across all zones and about 8 percent in Zone 1 where the climate is similar to that of the low-income customers in Track B.

Table F-4. Track A: SPP Results: Response by Customer Segments

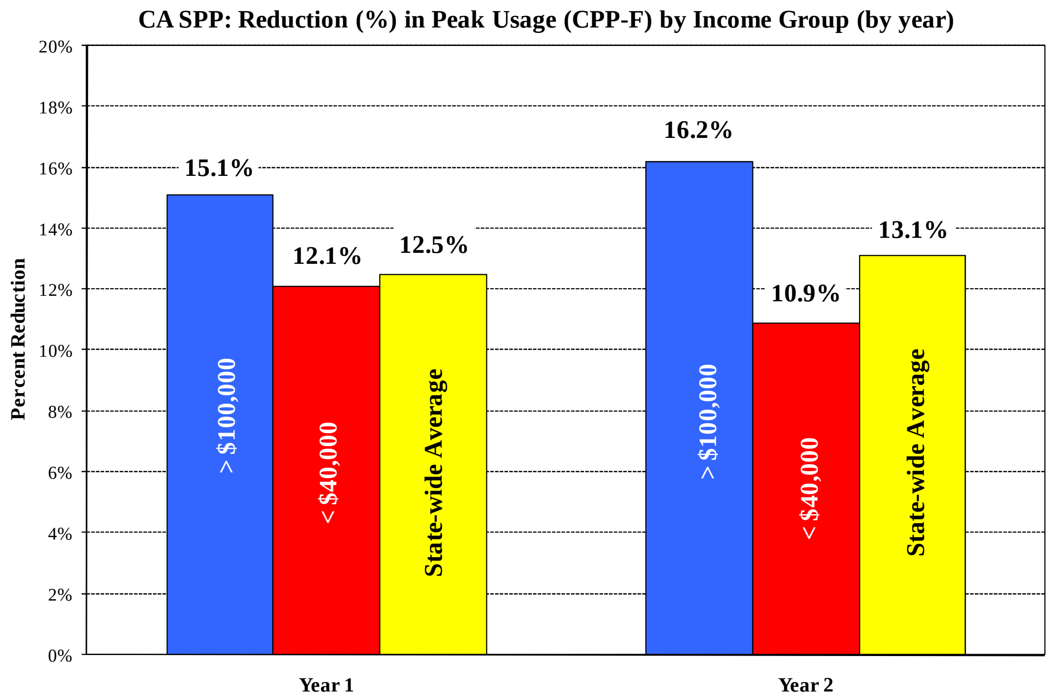
Customer Segment	**Customer Sub-Segment**	**Substitution between peak and off-peak consumption**	**Price elasticity of daily consumption**	**Percent reduction in critical-peak consumption**
Income	High ($100,000)	-0.101	-0.045	-16.15
Income	Low ($40,000)	-0.061	-0.035	-10.92
Care	No	-0.102	-0.029	-15.56
Care	Yes	-0.005	-0.014	-2.87
Average	All Zones	-0.076	-0.041	-13.06
Average	Zone 1	-0.039	-0.041	-7.61

(Source: Impact Evaluation of the California Statewide Pricing Pilot. Final Report. March 2005)

Figures F-1 and F-2 show the percentage reduction in peak period usage under the CPP fixed rate for low income (defined as less than $40,000) versus high income (defined as greater than $100,000) for each year of the pilot. As shown in Figure F-1, the low-income percentage reduction in peak usage (11-12 percent) is very similar to the statewide average response (12-13 percent). As expected, low-usage customers (those with usage that is 50 percent of the average) respond less than high-usage customers (defined as those with usage that is 200 percent of the average). Notably, although low usage is below the average in the first year (9.8 percent vs. 12.5 percent peak usage reduction), by the second year of the pilot (which is more likely to represent an ongoing program), low-usage response is much closer to the average response (12.2 percent vs. 13.1 percent reduction).

[13] The CARE results are difficult to interpret. CARE customers may not be as responsive as low-income customers in general because they are accustomed to getting a 20 percent discount on their electric bill.

Figure F-1: CA SPP - Percent Reduction in Peak Period Usage by Income Group[14]

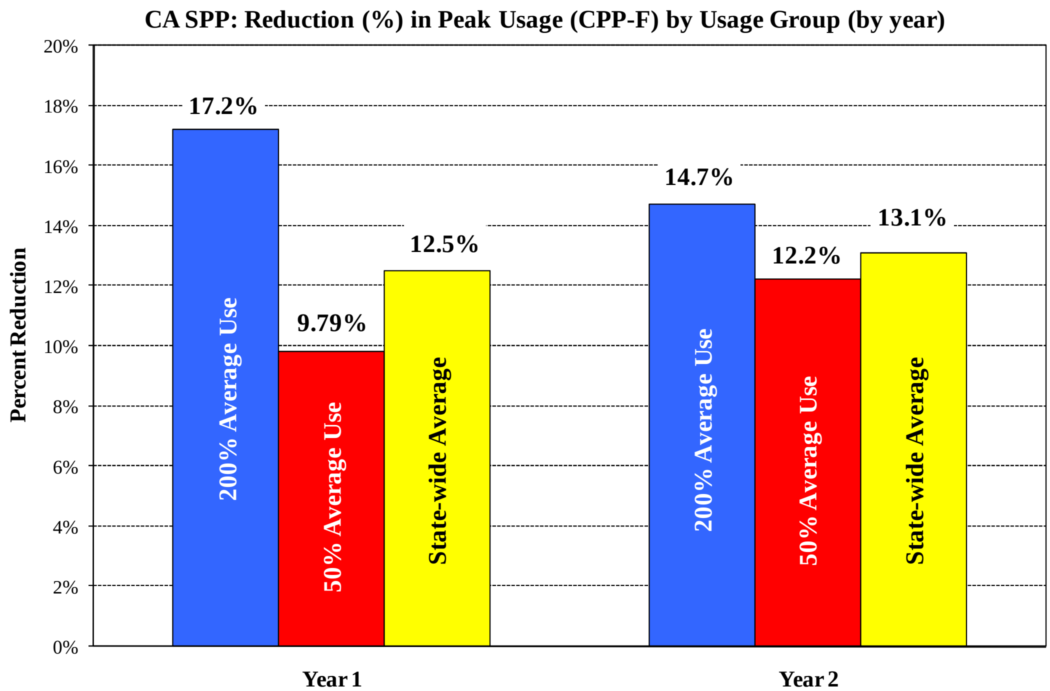


Summary

The results of the California pricing experiment show that low-income customers do respond to dynamic pricing by lowering usage during high-priced periods. This result holds even in areas with a temperate climate such as San Francisco as demonstrated by the Track B results. However, as demonstrated by the usage and income group analysis of the CPP conducted by Herter, focusing on income group alone is not sufficient and could lead to a faulty policy recommendation; usage must be taken into account. Low-income customers with low usage (which represent about 96 percent of all low-income customers) benefit from CPP in terms of bill savings. However, although low-income customers with high usage (about 4 percent of all low-income customers) may not benefit from CPP, they could benefit from PTR.

[14] Source: California Statewide Pricing Pilot, Summer 2003 Impact Analysis, 2004.

Figure F-2: CA SPP - Percent Reduction in Peak Period Usage by kWh Usage Group



Our major conclusion regarding usage targeting is the following:

- Low-usage customers save an average of 4 percent on their electricity bills whereas high usage customers save an average of 1.7 percent. Therefore, targeting dynamic pricing only to high-usage customers (as a proxy for high income as some have suggested) makes little sense from a policy perspective.

Our major conclusions regarding the effects of dynamic pricing on low-income customers are the following:

- Low usage customers are likely to experience bill savings regardless of income group. Therefore, it would make little sense to exclude low-income customers with low usage (about 96 percent of all low-income customers) from dynamic pricing.
- For the low-income customer with high usage, it may be useful to consider alternative dynamic pricing options such as PTR and information programs (similar to the Pepco pilot in the District of Columbia).

The SPP participant surveys show that about 87 percent of participants believe that dynamic pricing programs should be "probably" or "definitely" offered to all residential customers. Customers cited as a major program benefit becoming educated about the connection between electricity use and bill impacts.

A final concern that has been expressed is the cost of the meter, how fixed costs (such as the cost of a meter) are typically recovered as a flat fee per customer, and how this could have a negative impact for low-income customers. One solution is to consider a "volumetric" per kWh-based cost allocation method for such meters where the cost of the meter per customer per month varies directly with usage.[15]

[15] Roger Levy, Demand Response Research Center. PowerPoint presentation (no title).

In summary, there are many reasons to move forward with dynamic rate options for the vast majority of customers. Most important, customers respond to price signals and, as a result, customers on dynamic rates cost less to serve than those on standard flat or static rates. Second, a large majority of customers that have participated in dynamic rate programs believe that dynamic rates should be offered to all residential customers. Finally, dynamic rates give customers more control over their electric bill. If a small percentage of low-income customers with high usage (about 4 percent to 11 percent of the low-income group depending on the definition of high usage) are disadvantaged by a dynamic rate such as CPP, then one solution is to offer a PTR rate to these customers. However, for the low-income customers in the low-usage category (about 89 percent to 96 percent of the low income group), CPP can be beneficial.

APPENDIX G: INFORMATION TECHNOLOGIES FOR DEMAND RESPONSE

Potential information "technologies" for demand response are: in-home displays, detailed usage analysis, and prepayment metering. In-home displays can convey information to customers about their consumption and the price of electricity in real time, as well as provide messages from their electric utility. By making customers aware of the amount of electricity they are consuming and the relationship to their electricity bill, they may be more likely to conserve. There are a variety of in-home displays. Current experience with these devices and their impacts on customer electricity consumption are limited to experimental pilots. Below, we describe some of the specific in-home display technologies as well as other methods for providing information on electricity usage.

Real-time Feedback Monitors

Real-time feedback monitors that display information about current electricity consumption, the price of electricity, and the cumulative amount that has been spent on electricity can be installed in the home. A specific type of real-time feedback monitor is the PowerCost Monitor by Blue Line Innovations. This device also allows customers to view an estimate of the carbon dioxide emissions that are being produced as a result of their electricity consumption. The device can be self-installed on the electric meter by the customer. Information is wirelessly transmitted to the monitor, which can be installed anywhere in the house. The PowerCost Monitor can be purchased and installed by individual customers for under $150.

The effectiveness of the PowerCost Monitor was recently tested in a pilot by Hydro One in Ontario, Canada.[1] In the study, 500 of Hydro One's customers were equipped with the Power Cost Monitor and data on the customers' electricity usage was collected over a period of two and one-half years. The results of the pilot suggested that, on average, customers with the devices reduced electricity consumption by 6.5 percent (at a high level of statistical significance). This reduction was sustained over time and did not reduce over the duration of the pilot. Within the sample, customers with non-electric space heating were found to reduce consumption at a much higher level than those with electric space heating. This suggests that, for the customers with electric space heating, the feedback from the electric heating load would need to be separated from other end-uses in order to effectively encourage conservation for these customers. Overall, customers expressed a high level of satisfaction with the device, with over 60 percent indicating that the device was useful in helping to conserve energy. These results were achieved in the absence of any accompanying incentives or price schemes.

A 2004 study by Primen, Inc., identified several other devices that provide similar information, such as the Cent-a-Meter, EUM-2000, Energy Detective, and Greenwire Energy Monitor.[2] Prices for the devices range from $50 to $225, and most of these devices require additional installation costs, since installation cannot be performed by the customer.

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[1] Hydro One, "The Impact of Real-Time Feedback on Residential Electricity Consumption: The Hydro One Pilot," March 2006.

[2] Primen, Inc., "California Information Display Pilot Technology Assessment, Final Report," December 21, 2004.

The Energy Orb

A feedback device that has been tested in California is the energy orb (also known as the “glowing orb” or “ambient orb”), produced by Ambient Technologies. The energy orb is a small glass ball that changes colors as conditions on the electricity grid change. Prior to being used in this context in California, the orb was used as a tool for monitoring financial portfolios. In the stock market context, the orb could be set so that when certain stock prices were increasing, it would turn a mild blue color. As the stock prices began to drop, the color changed to red, encouraging orb owners to more actively manage their portfolios.

In California, the impacts of the energy orb were tested through the California Information Display Pilot (IDP).[3] In this study, the energy orb was used in conjunction with CPP rates.[4] The orb changed colors as the customer’s electricity rate increased, and flashed for four hours prior to a critical event. A total of 62 customers participated in the orb experiment. Results of the study suggest that residential customers reduced demand during the critical event due to the orb, and also during the four-hour warning period. Based on a survey of residential customers, 70 percent indicated that the orb led to a change in their behavior. A consistent demand impact was not detected for commercial customers. This study was limited by the small sample size and the results were not statistically significant. Only two customers indicated that they would be willing to pay over $25 for the orb.

The energy orb can also be used to provide customers with signals for emergency demand reductions.

Detailed Monthly Usage and Bill Analysis

A straightforward way to provide customers with information about their electricity use is through a monthly analysis of their energy consumption. In addition to measuring the energy orb impacts, the California IDP also measured the impact of a monthly newsletter that provided customers with a detailed breakdown of their usage patterns for the previous month, along with suggestions for reducing consumption to save money on their electricity bills. The newsletter used bill determinants and customer survey information to set benchmarks based on the prior month’s use and to compare individual customers’ usage to that of other customers in a “report card” format. The participating customers were equipped with AMI, so the newsletter was also able to provide them with specific information about their critical peak consumption and the benefits of load shifting. This information was conveyed through the mail, email, or an Internet website.

The results of the study showed that about 30 percent of residential and commercial and industrial customers said that the newsletter led to changes in their behavior. The remaining customers said that it did not change their behavior, or they did not even recall the newsletter. Additionally, the customers indicated that the energy orb was a more effective tool for inducing changes in their behavior.

Prepayment Metering

Prepayment metering can also have the effect of making customers more aware of their electricity consumption. While originally designed to help utilities collect payments from customers with poor credit histories, prepayment metering requires customers to pay in advance for the quantity of electricity that they

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[3] Nexus Energy Software, Opinion Dynamics Corporation, and Primen, “Information Display Pilot, Final Report,” January 5, 2005.

[4] Another similar technology, The Comverge Customer Alert Device, was also considered for the study but was not tested. The device displays sounds and colored lights to convey signals about prices.

will be using. As they deplete the purchased amount, they typically receive a warning that they need to buy more. Otherwise, the supply of electricity is cut off from the house until the customer has "fed" the meter.

In Ireland, Northern Ireland Electricity has keypad meters installed for 20 percent (125,000) of its customers. A study found that, with training, customers were able to reduce consumption by 11 percent. Even without training, customers reduced consumption by 4 percent. Prepayment programs in the U.S. include Tacoma, Washington's "PayGo" program and Salt River Project's program, which has achieved 10 to 20 percent savings across 31,000 participating customers.[5]

[5] Kathleen Davis, "Prepaid Metering Can Bring Strays Back to Your Fold," *Utility Automation and Engineering T&D*, May 2003.

APPENDIX H: ESTIMATION OF USAGE IMPACTS IN PRISM

The PRISM model predicts the changes in electricity usage that are induced by time-varying rates.[1] One important feature of PRISM is its capability to model nonlinearities in the estimation of usage impacts when price changes extend from minimal to maximal. In PRISM, the usage impacts increase at a decreasing rate when prices are increased in a linear fashion. This nonlinear relationship is reflected in the shape of response curves that show the percentage impact on load due to price changes. In this appendix, we briefly describe the demand equations in PRISM and demonstrate through the use of demand curves, response curves, and own-price elasticities how PRISM handles nonlinearities in the estimation of usage impacts.

The PRISM model predicts the usage impacts by utilizing the parameter estimates of a constant elasticity of substitution (CES) demand system.[2] This demand system consists of two equations. The substitution equation predicts the ratio of peak to off-peak quantities as a function of the ratio of peak to off-peak prices and other factors. The daily energy usage equation predicts the daily electricity usage as a function of daily price and other factors. Once the demand system is estimated, resulting equations are solved to determine the changes in electricity usage associated with a time-varying rate. Derivations for these equations are provided at the end of this appendix.

Parameter estimates from the demand system may also be used to infer two practical measures of customer responsiveness to the time-varying rates: the elasticity of substitution and the daily price elasticity. The *elasticity of substitution* can be calculated from the substitution equation and indicates the percentage change in the peak to off-peak usage ratio due to 1 percent change in the peak to off-peak price ratio. The *daily price elasticity* can be calculated from the daily usage equation and shows the percentage change in daily usage associated with 1 percent change in daily electricity prices. Although informative about substitution and conservation patterns of customers, substitution and daily usage elasticities are less direct measures of price responsiveness. The two more common measures of price responsiveness are the own- and cross-price elasticities of demand. For small price changes, it is possible to infer own- and cross-price elasticities from substitution and daily price elasticities (these derivations are provided at the end of this appendix). However, when price changes are large; it is more accurate to derive these elasticities through impact simulation for different prices and applying elasticity formulas. For large price changes, the arc elasticity approach provides more accurate elasticity estimates compared to the point elasticity approach. The arc elasticity formula uses the average of the initial and final points as a base when calculating the percentage changes in quantity and price whereas the point elasticity formula uses the initial point as the base for the same calculation.

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[1] PRISM has the capability to predict these changes for peak and off-peak hours for both critical and non-critical peak days. Moreover, PRISM allows predictions to vary by other exogenous factors such as the saturation of central air conditioning and variations in climate.

[2] For the description of the CES model, see Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot," March 2005.

In our demonstrations, we adopt the arc elasticity approach to calculate the own-price elasticity of demand. Both formulas are provided below:

$$\text{Arc Elasticity} = \frac{Q_2 - Q_1}{(Q_1 + Q_2)/2} \Big/ \frac{P_2 - P_1}{(P_1 + P_2)/2}$$

$$\text{Point Elasticity} = \frac{Q_2 - Q_1}{Q_1} \Big/ \frac{P_2 - P_1}{P_1}$$

Below we summarize our simulation results by introducing demand curves, response curves, and own-price elasticities for each of the peak and off-peak time periods on critical pricing days for the average customer, for customers with central air conditioning (CAC), and for customers without CAC.

Demand Curves for Peak and Off-Peak Periods on Critical Days

The demand curves in Figure H-1 represent how the peak demand varies with the peak period price on critical days; all other factors are held constant. At a price of $0.13 per kWh, the peak price under the non-time-varying rate, the starting values for peak period energy use are 1.22 kWh per hour for the average customer, 1.32 kWh per hour for CAC customers, and 0.85 kWh per hour for non-CAC customers. At a price of $1.30 per kWh, a hypothetical critical peak price, peak consumption falls to 1.03 kWh, 0.96 kWh, and 0.78 kWh for the average, CAC, and non-CAC customers, respectively. As shown in Figure H-1, the ownership of CAC affects the slope of the demand curves. The demand curve is flatter for CAC customers who are more price-responsive and therefore reduce their peak demand more in response to time-varying rates. In contrast, the demand curve for non-CAC customers is steeper, implying less price responsiveness. Figure H-2 shows off-peak period demand curves on critical days. The differences in the slopes still hold for different types of customers but are less prominent in the case of off-peak demand. The more vertical shape of these curves implies that off-peak demand is less sensitive to time-varying rates compared to peak demand.

Figure H-1. Residential Customer Peak Demand Curves on Critical Days

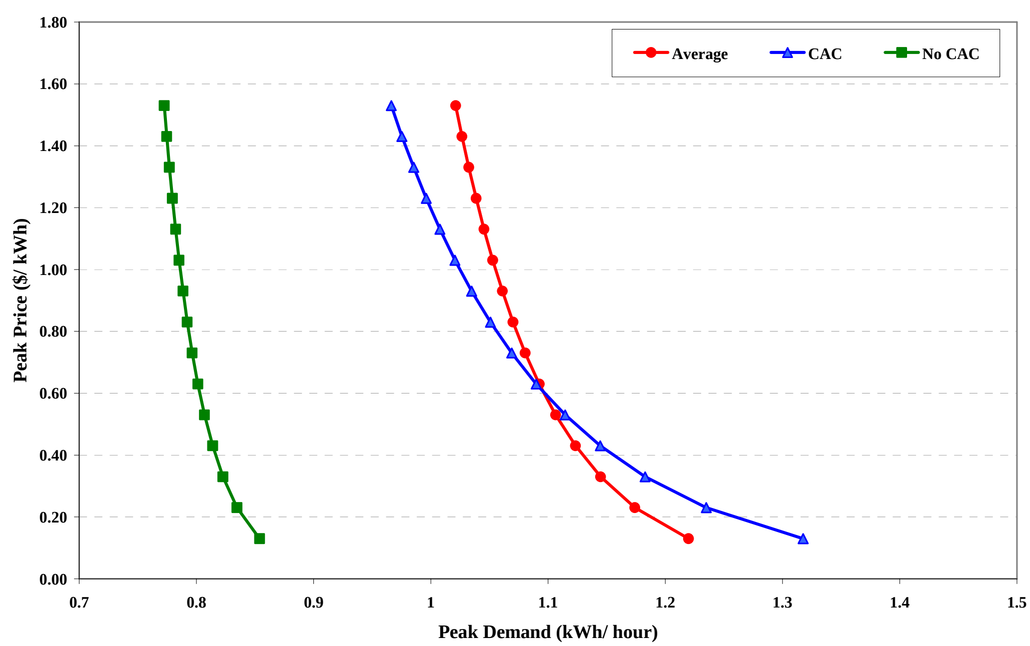
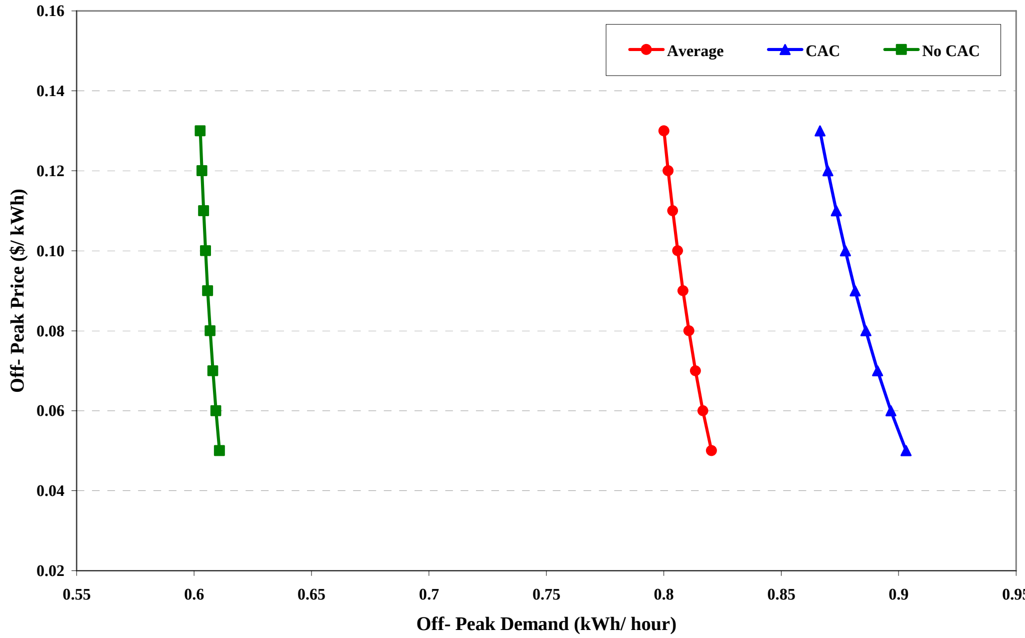


Figure H-2. Residential Customer Off-Peak Demand Curves on Critical Days



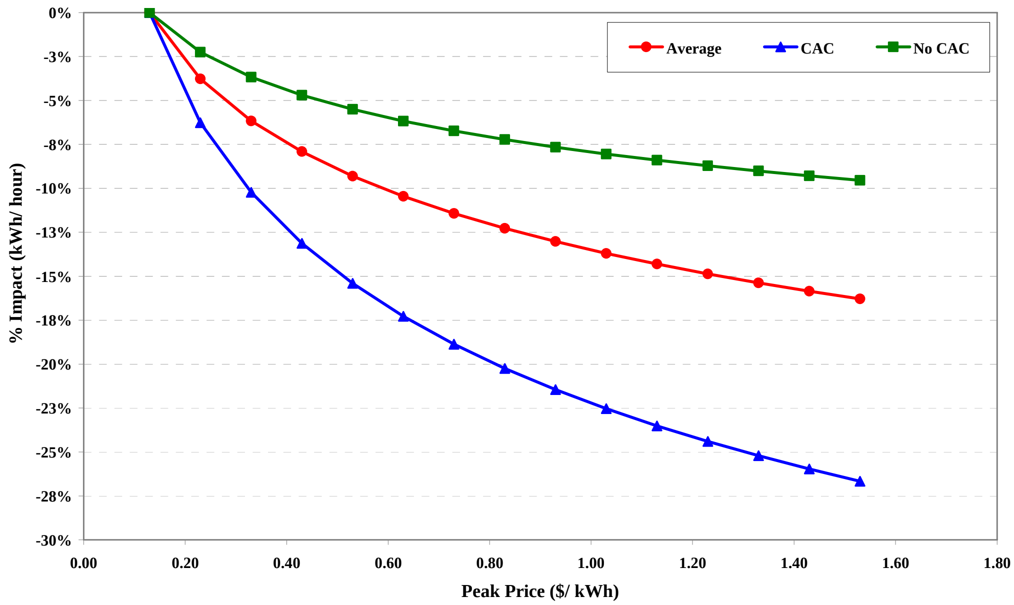
Response Curves for Peak and Off-Peak Periods on Critical Days

The response curves in Figure H-3 demonstrate how the percentage impact on peak period energy usage varies with the peak-period price on critical days. These curves show that the percentage impact on the peak period energy usage increases as prices increase, but at a decreasing rate. This nonlinear relation between usage impacts and prices is reflected in the concave shape of the response curves.

To clarify how PRISM models the relationship between the prices and the percentage impact on load in a nonlinear fashion, consider the following example.

For the average customer, peak period energy usage decreases by 4 percent when the peak price increases from $0.13 per kWh to $0.23 per kWh. However, peak period energy usage decreases by only 8 percent when the peak price is increased from $0.13 per kWh to $0.43 per kWh. This example demonstrates that the load impact increases by onefold (rather than twofold) when the price increases by twofold.

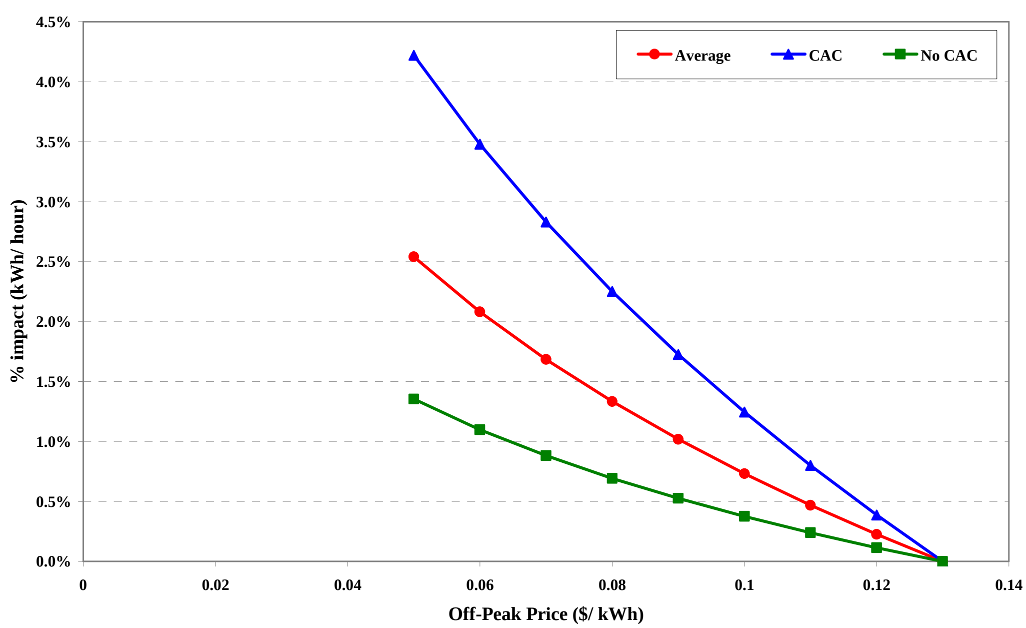
Figure H-3. Residential Customer Peak Response Curves on Critical Days



We can also observe the differences between customer types in their price responsiveness from these response curves. For a given price increase, non-CAC customers are the least responsive while CAC customers are the most responsive.

Figure H-4 shows the response curves for the off-peak period on critical days. Similar to the peak response curves, the off-peak response curves are also nonlinear. However, the flatter off-peak response curves in Figure H-4 demonstrate the limited price responsiveness during off-peak periods (compared to peak periods).

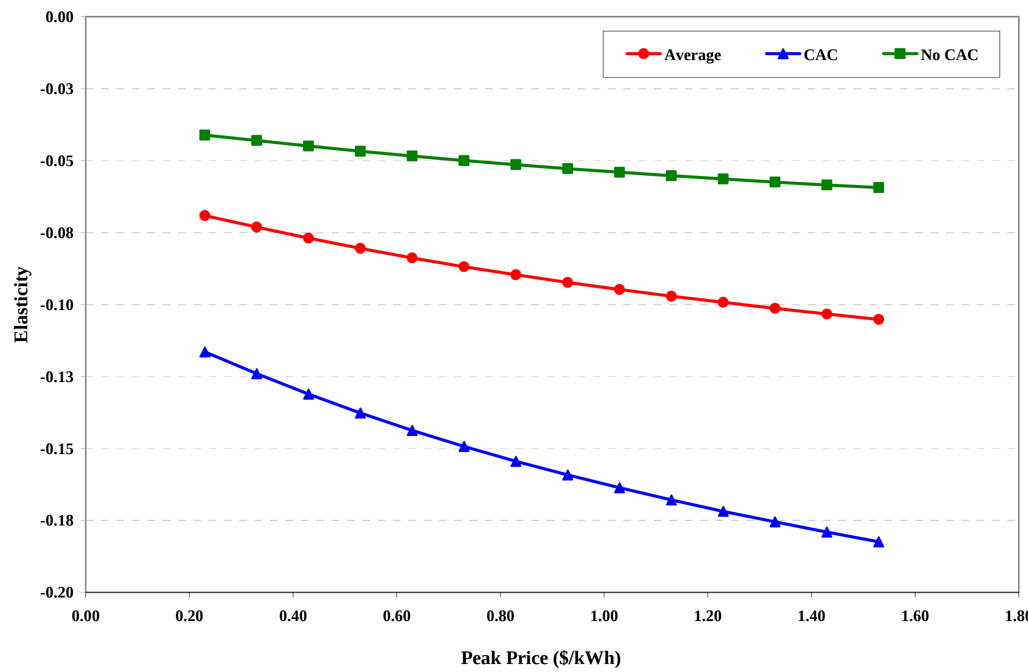
Figure H-4. Residential Customer Off-Peak Response Curves on Critical Days



Own-price Elasticities on Critical Days

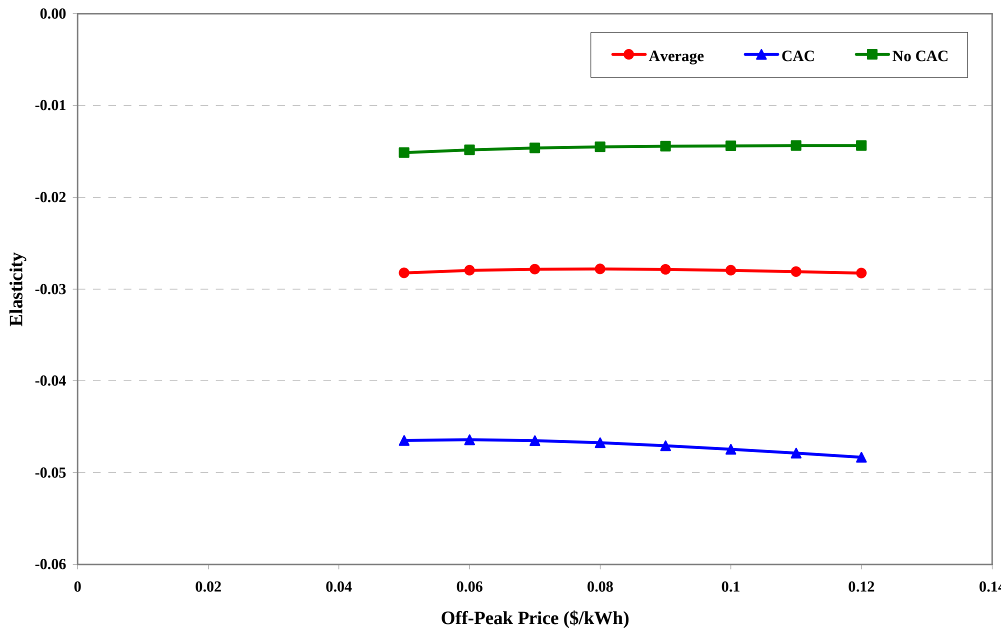
The own-price elasticity of demand is the most straightforward measure of price responsiveness. It shows the percentage change in demand due to 1 percent change in price. It is possible to derive an own-price elasticity of demand through simulation when there are large changes in price. We calculate the own-price elasticity of demand for peak and off-peak periods by simulating the changes in electricity usage for different price levels and then applying the arc price elasticity formula to the simulated impacts and prices. For the impact simulation, we start with a price of $0.13 per kWh and increase the price by 10-cent increments to a maximum of $1.53 per kWh. Figure H-5 shows the resulting own-price elasticities of peak demand by customer type. The elasticities range from -0.07 to -0.11 for average customers, -0.12 to -0.18 for CAC customers, and -0.04 to -0.06 for non-CAC customers. Consistent with the prior results, CAC customers have the most elastic peak demand while the non-CAC customers have the least elastic peak demand.

Figure H-5. Implicit Own Price Elasticity for Peak Demand on Critical Days



For the off-peak impact simulation, we start with $0.13 per kWh and decrease the price by one-cent increments to a maximum of $0.05 per kWh. Figure H-6 shows the resulting own-price elasticities of off-peak demand by customer. The own-price elasticities are negative but relatively flat – approximately -0.03 for average customers, -0.05 for CAC customers, and -0.015 for non-CAC customers.

Figure H-6. Implicit Own-price Elasticity for Off-peak Demand on Critical Days



Derivation of PRISM Demand Equations

This section presents the derivation of the equations in the PRISM model to predict the changes in electricity usage as a result of time-varying prices.[3] Derivations are provided for a general, three-period TOU pricing scheme. The two-period case where there are only peak and off-peak periods is a special case of this general model.

When the TOU pricing scheme includes only two periods (peak and off-peak), only the elasticity of substitution between peak and off-peak usage is estimated. Thus, when the following equations are applied, we assume that $b_{12} = b_{32}$.

In the reference case with no time varying prices, the following relationships hold:

$$\ln\left(\frac{Q_1}{Q_2}\right) = a_{12} + b_{12}\ln\left(\frac{P_1}{P_2}\right) \qquad (0.1)$$

$$\ln\left(\frac{Q_3}{Q_2}\right) = a_{32} + b_{32}\ln\left(\frac{P_3}{P_2}\right) \qquad (0.2)$$

where Q_i = Energy Usage in Period i, and P_i = Price per Unit of Energy in Period i.

Also,

$$\bar{Q} = Q_1 + Q_2 + Q_3 \qquad (0.3)$$

[3] This section heavily draws on Appendix 8 of Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot," March 2005.

When time-varying prices are introduced (denoted by primes), the following relationships hold:

$$\ln\left(\frac{Q_1^{'}}{Q_2^{'}}\right) = a_{12} + b_{12}\ln\left(\frac{P_1^{'}}{P_2^{'}}\right) \tag{0.4}$$

$$\ln\left(\frac{Q_3^{'}}{Q_2^{'}}\right) = a_{32} + b_{32}\ln\left(\frac{P_3^{'}}{P_2^{'}}\right) \tag{0.5}$$

and,

$$\overline{Q}^{'} = Q_1^{'} + Q_2^{'} + Q_3^{'} \tag{0.6}$$

We start the derivations by subtracting (1.1) from (1.3):

$$\left(\ln\left(\frac{Q_1^{'}}{Q_2^{'}}\right) = a_{12} + b_{12}\ln\left(\frac{P_1^{'}}{P_2^{'}}\right)\right) - \left(\ln\left(\frac{Q_1}{Q_2}\right) = a_{12} + b_{12}\ln\left(\frac{P_1}{P_2}\right)\right) \tag{0.7}$$

$$\ln\left(\frac{Q_1^{'}}{Q_2^{'}}\right) = \ln\left(\frac{Q_1}{Q_2}\right) + b_{12}\left(\ln\left(\frac{P_1^{'}}{P_2^{'}}\right) - \ln\left(\frac{P_1}{P_2}\right)\right) \tag{0.8}$$

We set the right hand side of (1.8) to A_{12} **:**

$$A_{12} = \ln\left(\frac{Q_1}{Q_2}\right) + b_{12}\left(\ln\left(\frac{P_1^{'}}{P_2^{'}}\right) - \ln\left(\frac{P_1}{P_2}\right)\right) \tag{0.7}$$

$$\ln\left(\frac{Q_1^{'}}{Q_2^{'}}\right) = A_{12} \quad \text{or} \quad \ln(Q_1^{'}) = A_{12} + \ln(Q_2^{'}) \tag{0.8}$$

Now, we exponentiate (1.10) and arrive at:

$$\begin{aligned} &\exp\ln(Q_1^{'}) = \exp(A_{12} + \ln(Q_2^{'})) \\ &\Rightarrow Q_1^{'} = e^{A_{12}} Q_2^{'} \end{aligned} \tag{0.9}$$

Through a similar process, we can arrive at:

$$\ln\left(\frac{Q_3^{'}}{Q_2^{'}}\right) = A_{32} \tag{0.10}$$

$$A_{32} = \ln\left(\frac{Q_3}{Q_2}\right) + b_{32}\left(\ln\left(\frac{P_3^{'}}{P_2^{'}}\right) - \ln\left(\frac{P_3}{P_2}\right)\right) \tag{0.11}$$

$$\begin{aligned} &\exp\ln(Q_3^{'}) = \exp(A_{32} + \ln(Q_2^{'})) \\ &\Rightarrow Q_3^{'} = e^{A_{32}} Q_2^{'} \end{aligned} \tag{0.12}$$

This leaves us with:

$$Q_1^{'} = e^{A_{12}} Q_2^{'}$$

and

$$Q_3^{'} = e^{A_{32}} Q_2^{'}$$

Then we insert both of these equations into (1.3):

$$\overline{Q}^{'} = e^{A_{12}} Q_2^{'} + Q_2^{'} + Q_2^{'} e^{A_{32}} \tag{0.13}$$

$$\overline{Q}^{'} = Q_2^{'}(1 + e^{A_{12}} + e^{A_{32}}) \tag{0.14}$$

$$Q_2^{'} = \frac{\overline{Q}^{'}}{(1 + e^{A_{12}} + e^{A_{32}})} \tag{0.15}$$

We finally arrive at:

$$\begin{aligned} Q_1^{'} &= e^{A_{12}} Q_2^{'} \\ Q_2^{'} &= \frac{\overline{Q}^{'}}{(1 + e^{A_{12}} + e^{A_{32}})} \\ Q_3^{'} &= e^{A_{32}} Q_2^{'} \end{aligned} \tag{0.16}$$

The two-period case is a special case of this set of relationships where $A_{32} = 0$.

Derivation of Own- and Cross-price Elasticities from PRISM Demand Equations

Point estimates of the own-price and cross-price elasticities of demand can be derived from the CES demand model.[4] The first equation of the demand model expresses the ratio of energy usage in each rate period as a function of the ratio of prices in each period, while the second equation expresses daily electricity consumption as a function of daily electricity prices. It is important to note that the equations presented in this section are based on energy usage for each rate period, rather than energy usage per hour.

The first equation of the CES demand system:

$$\ln\left(\frac{Q_p}{Q_{op}}\right) = a + b\ln\left(\frac{P_p}{P_{op}}\right) \tag{2.1}$$

where:

Q_p = Peak period energy use
Q_{op} = Off-peak period energy use
P_p = Peak period energy price
P_{op} = Off-peak period energy price

If there are two usage periods, then the following identity holds:

$$Q_d = Q_p + Q_{op} \tag{2.2}$$

where,

Q_d =Daily energy use

The second equation of the demand system:

$$\ln Q_d = c + d\ln(P_d) \tag{2.3}$$

where:

$$P_d = w_p P_p + w_{op} P_{op} \tag{2.4}$$

P_d =Average daily electricity price
w_p = total peak period electricity use
w_{op} =total off-peak period electricity use

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[4] This section heavily draws on Appendix 9 of Charles River Associates, "Impact Evaluation of the California Statewide Pricing Pilot," March 2005.

Then, we define the following budget shares:

$$z_p = \left(\frac{w_p P_p}{w_p P_p + w_{op} P_{op}} \right) \tag{2.5}$$

$$z_{op} = \left(\frac{w_{op} P_{op}}{w_p P_p + w_{op} P_{op}} \right) \tag{2.6}$$

Using the relevant equations and applying the chain rule, we derive the following expressions for the own- and cross-price elasticities of demand:

Own-price elasticity in the peak period: $$\eta_p = \frac{\partial \ln Q_p}{\partial \ln P_p} = w_{op} b + d z_p \tag{2.7}$$

Own-price elasticity in the off-peak period: $$\eta_{op} = \frac{\partial \ln Q_{op}}{\partial \ln P_{op}} = w_p b + d z_{op} \tag{2.8}$$

Cross-price elasticity in the peak period: $$\eta_{p,op} = \frac{\partial \ln Q_p}{\partial \ln P_{op}} = -w_{op} b + d z_{op} \tag{2.9}$$

Cross-price elasticity in the off-peak period: $$\eta_{op,p} = \frac{\partial \ln Q_{op}}{\partial \ln P_{op}} = -w_p b + d z_p \tag{2.10}$$

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