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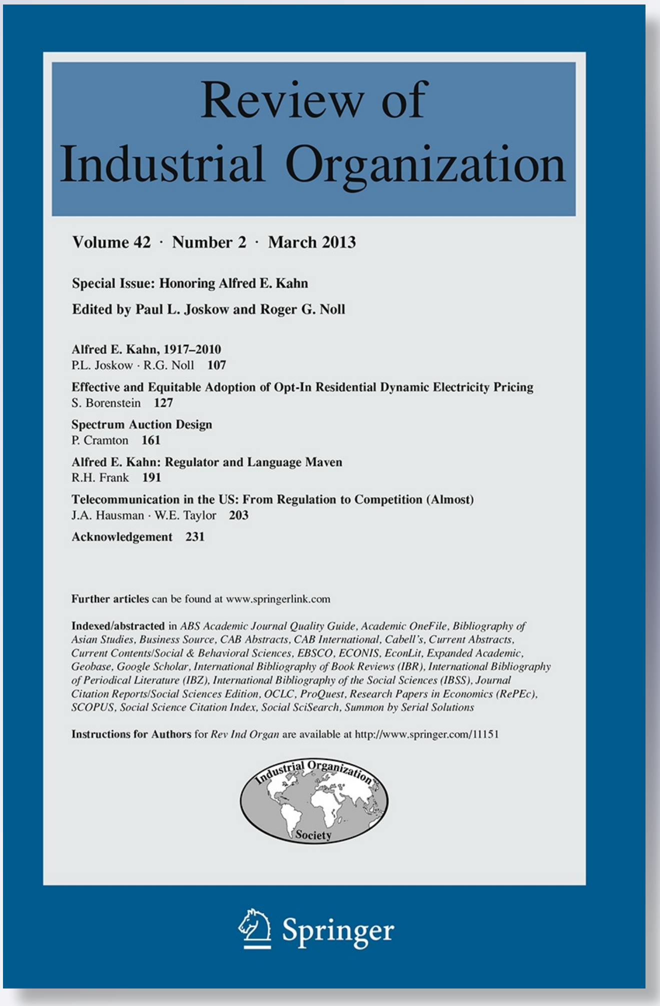

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Effective and Equitable Adoption of Opt-In Residential Dynamic Electricity Pricing

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Abstract Time-varying retail electricity pricing is very popular with economists, but has little support among regulators and consumers. I propose an opt-in time-varying residential pricing plan that would be equitable to both customers who opt in and those who don't. Low-income households would, on average, see almost no change in their bills under time-varying pricing, while low-consumption households would see their bills decline somewhat and high-consumption households would see their bills rise. Most importantly, I show that the opt-in approach is unlikely to increase the flat rate charged to other customers by more than a few percentage points.

Keywords Real-time pricing · Critical-peak pricing · Tariff design

1 Introduction

Economists who study electricity markets are virtually unanimous in arguing that time-varying retail pricing for electricity would improve the efficiency of electricity systems and would lower the overall cost of meeting electricity demand. Because it is very costly to store electricity, wholesale electricity prices can vary greatly—by more than an order of magnitude—over a single day. Yet, retail prices almost never change over such short time periods, so retail customers are given little or no incentive to reduce consumption when power is expensive. Retail prices that more accurately reflect the time-varying true cost of power would shift usage to lower cost periods in a way that would ultimately improve the economic welfare of customers. In addition to the direct cost impact, greater adoption of dynamic pricing—time-varying pricing where prices are set a day or less in advance in order to be responsive to system

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conditions—could potentially also help in the integration of intermittent generation resources, such as wind or solar power, and could improve the cost-effectiveness of electric vehicles.

Yet, only the simplest forms of time-varying pricing have been widely adopted for commercial and industrial customers in the US—time-of-use pricing, in which a price for the peak period and a different price for the off-peak period (and in some cases, a third "shoulder" period) are set for months or even a year at a time. At the residential level, time-varying pricing has gotten very little traction in any form. In this paper, I examine the reasons for customer resistance to time-varying pricing, and particularly dynamic pricing, and I present an approach to opt-in dynamic pricing that might increase acceptance and also improve the effectiveness of the pricing. I then study the likely distributional impact of dynamic pricing by using stratified random samples of residential electricity customers in the service territories of Pacific Gas & Electric (PG&E) and Southern California Edison (SCE), which are the two largest utilities California.

The analysis is very much in the spirit of Alfred Kahn—rooted in fundamental economic principles, but aimed at the practical implications of the economics. Just as important, a primary goal is to use the power of microeconomics to craft implementation strategies that help gain broader acceptance among non-economists for rational economic systems and pricing. In his remarkable career, Fred made outstanding contributions in all three areas: fundamental economic analysis, application of economics to major public policy problems, and communicating and adapting the economic approach to build support for rational policymaking among non-economists.[1] I was lucky enough to work for Fred at the Civil Aeronautics Board in 1978–1979 and to speak with him many time in the following decades. His influence on the economics and practice of government regulation of business was unrivaled.

2 Variations in Retail Electricity Pricing

Throughout the United States, most residential customers purchase electricity at a simple constant price per kilowatt-hour that does not vary over time within a billing period. A significant minority—probably around one-third—of customers face "increasing-block pricing," under which marginal price rises as the customer consumes more power over the billing period. The prices, however, do not depend on the time at which the power is consumed. Such time-insensitive rates probably cover over 99 % of residential customers.

In terms of time-sensitive retail electricity tariffs, the opposite end of the spectrum would be a real-time pricing (RTP) structure in which the price varies from hour to hour (or even more frequently) which would reflect changes in the wholesale price of electricity. RTP prices are dynamic, which means that they are set at the time that the transaction takes place or shortly before hand (generally less than 36 h). Many hybrid forms lie between these approaches. The most common is time-of-use (TOU) pricing in which different prices are charged at different times of the day or week.

[1] For a concise example of Fred's approach, see Kahn (1979).

TOU pricing is not dynamic; the prices and the times at which those prices will be charged are set months in advance, so they cannot reflect shorter run variation in the supply/demand balance of the wholesale electricity market.

Critical peak pricing (CPP) is a hybrid form that combines a static price structure, either constant or TOU, with occasional dynamic departures from the tariff when demand is high and power is in short supply. Typically, a CPP structure permits the utility to declare a critical peak day up to 10–15 days per year. Such declarations normally mean that the price of electricity during the peak consumption part of the day (e.g., 1 pm–7 pm) is many times higher than it would otherwise be. A representative CPP tariff would, for example, start with a TOU price structure of $0.15/kWh from 10am to 7pm on weekdays and $0.06/kWh at all other times. Then, up to 15 days per year, the seller may declare a critical peak day, with that declaration usually made in the afternoon of the previous day. On the critical peak day, the price during the peak period (or some part of it) might be, for instance, $0.75/kWh. CPP can provide some of the same incentives as RTP—particularly to conserve power when the supply is very constrained—while being substantially simpler and easier to explain to customers than RTP. One disadvantage of CPP is the coarseness of pricing; that the price is either set at a "normal" level or at an extremely high level. There is nothing in between. Also, the limited number of times that the utility can call a critical peak day creates strategic concerns in declaring a critical peak that are not necessarily well-aligned with efficient pricing. I return to this issue below.

3 Benefits of Dynamic Pricing

The focus of this paper is not on measuring or listing the benefits of dynamic pricing. I and others have written extensively on the subject.[2] Still, it is worth recalling the benefits that motivate sellers and regulators to consider implementing more complex pricing structures than consumers are used to.

The primary attraction of dynamic pricing is that it allows the retail power provider to give buyers an incentive to reduce consumption at times when the market supply is strained and potentially to substitute towards consumption at times when supply is plentiful. By doing so, it lowers the need for investment in reserve generation capacity for which the capital costs and some maintenance costs must be paid regardless of how frequently the capacity is used. At the same time, it raises the capacity factor of the generation capacity in the market, thus lowering the capital costs per kilowatt-hour. My previous research suggest that savings of at least 3–5 % of electricity generation costs are likely to result.[3]

A second benefit of dynamic pricing is that giving customers an incentive to reduce consumption when wholesale prices skyrocket reduces the incentive of a seller with market power to withhold electricity from the market in order to drive up prices. The incentive of a seller to reduce output depends in large part on the elasticity of demand. If buyers respond rapidly to price increases by significantly lowering the quantity

[2] See Borenstein (2005a,b), and Faruqui and Hledik (2009) among others.

[3] See Borenstein (2005a).

they demand, then withholding output will cause the producer to lose sales without getting much benefit in higher prices. With static retail prices, consumers have no incentive at all to respond if a seller tries to exercise market power in the wholesale market, because the retail price they see is unaffected. In contrast, if the utility that purchases wholesale power can credibly threaten to reduce its purchases if the price goes up—which is only credible if the end-use customers of the utility reduce their consumption—then sellers will find the exercise of market power to be less profitable. Had the California market been using dynamic pricing during the electricity crisis of 2000–2001, sellers would have found it less profitable to withhold power in order to drive up prices and as a result would have been less inclined to do so.[4]

Both of these benefits follow from the fact that dynamic pricing allows the retail prices that consumers face to reflect more accurately the true acquisition costs in the upstream wholesale market. The cost of acquiring power in the wholesale market can fluctuate by many times the average price within just a few hours. The extreme price fluctuations result from the fact that electricity is not storable, demand and supply fluctuate somewhat unpredictably, demand tends to be fairly insensitive to price, and supply may also be price-insensitive if the market is already using nearly all of the available capacity. These factors are exacerbated when there is a seller in the market that is large enough to influence price, because that seller's incentive to withhold power is greatest at the time when the market is already strained.

Dynamic pricing also has the potential to help integrate intermittent generation resources such as wind power and solar power. Integration of these intermittent resources generally focuses on the need for standby generation to compensate for exogenous fluctuations in their output. Dynamic pricing makes it possible to match more closely demand fluctuations to the exogenous supply fluctuations and, thus, reduce the system costs of integrating these renewable energy sources.

The social returns to dynamic pricing may also increase with the widening adoption of electric vehicles. Beyond just scheduling vehicle charging at off-peak times, using a more sophisticated response to fluctuating prices could reduce both the cost of charging these vehicles and the cost of accommodating them on the grid.

4 Barriers to Acceptance of Dynamic Pricing

Though the benefits from dynamic pricing are potentially quite significant, the tariff changes that are necessary for adoption often face substantial barriers. Some of the objections relate to the cost of infrastructure and associated concerns: the cost of purchasing and installing smart meters, the accuracy of such meters, the need for changes in back-office billing systems and the health, security and privacy issues that smart meters may or may not raise. I do not address these issues. Some of these are no doubt reasonable concerns, but I do not claim to have any insights that shed light on them.

I focus on the economic impact on consumers of implementing dynamic pricing, on the assumption that the smart meters are already installed and that the infrastructure-related concerns have been addressed. Even setting aside infrastructure issues,

[4] See Borenstein (2002) and Borenstein et al. (2002).

recent experience has made it clear that at least some consumer groups will object specifically to implementation of dynamic pricing.[5]

Probably the most common objection to implementation of a dynamic pricing tariff is the concern that it would be mandatory, or even that it would be the default option, which would require non-participants to take an action in order to opt out. While mandatory or default dynamic pricing tariff may be good policy, it is clear that it is unlikely to be politically acceptable for residential customers in the near future. Therefore, I begin from the constraint that the new tariff will have to be offered on an opt-in basis, and most customers will likely remain on the default tariff in the short run.

Even opt-in dynamic pricing faces resistance from some organizations that are concerned that consumers will not understand the nature of the tariff to which they are opting in. In particular, some households with high consumption at peak times could find that their bills are much higher on average under the new tariff. Closely related, there is concern that even if the average bill of a household is no higher, it will be substantially more volatile, which the household will have difficulty managing.[6]

These concerns are voiced particularly strongly on behalf of low-income households who have less resilience to financial shocks. More generally, organizations that represent low-income customers express concern that dynamic pricing will raise the electricity bills of the needy on average, or at least that a significant subgroup will be made worse off.

In the next section of this paper, I suggest approaches to transitioning to residential dynamic pricing that attempt to address these concerns, an opt-in dynamic pricing tariff that may help to elicit substantial participation by well-informed customers. The implementation minimizes the risks that a customer with peaky demand will make a costly mistake of choosing to be on the dynamic tariff. It also offers options to minimize the volatility of bills for customers who do choose to switch to the dynamic pricing tariff. I then study empirically the potential impact of such a transition and new tariff on customers in general and on low-income customers in particular.

Before proceeding, however, it is worthwhile to state explicitly four fundamental goals of residential tariff design:[7]

I. *Revenue Adequacy:* In aggregate, revenues raised from residential tariffs should cover the cost of providing power to the residential sector.[8]

II. *Efficient Pricing:* Prices should reflect the marginal cost of providing power at the time and location that it is provided so that the customer has efficient incentives to consume.

III. *Minimizing Volatility:* Customers should be able to insure in some way against excessive volatility in their electricity bills.

[5] See Alexander (2010) for a recent discussion of consumer concerns.

[6] See Maryland Public Service Commission (2010, pp. 49–51) and American Association Of Retired Persons et al. (2010).

[7] These are a subset of the principles that are presented by Bonbright et al. (1989).

[8] In reality, there may be some cross subsidy among residential, commercial and industrial customers, but taking that cross subsidy as given, revenues must cover the cost of power plus or minus the cross subsidy. This doesn't change the fundamental goal.

IV. *No Undue Cross-Subsidization:* Persistent cross subsidies among customers should be avoided except to the extent that they are designed explicitly to help customers who are deemed needy or disadvantaged.

Traditional flat rate residential tariffs have done a relatively good job of meeting goals I and III, but have performed poorly on II and IV. Flat rates have been designed to meet expected cost forecasts—particularly when most of the cost is predictable amortization of capital investments—but they obviously are not so reliable when fuel or wholesale electricity costs shift significantly in the middle of the typical multi-year ratemaking period. In those cases, revenue shortfalls or surpluses are generally offset by adjustments in the flat rate over succeeding tariff periods. While this approach assures revenue adequacy and reduces volatility of bills, it results in prices that can deviate substantially from efficient levels and it introduces substantial cross subsidies: (a) between those who consume at peak versus off-peak, (b) between those who consume in high-cost locations versus those who consume in low-cost locations, and (c) between those who consume in a period in which retail prices are not adequate to cover wholesale costs and a period in which they are set above costs to make up for previous shortfalls.

Taking as given that the utility will be allowed to recover its costs over some reasonable time horizon, any cost that is not paid by one customer must be absorbed by others. Traditional flat rate tariffs result in a form of inter-household group pooling of revenue responsibility. Just as with insurance, however, all customers do not necessarily impose the same *average* costs on the system. If rates do not recognize these differences they result in cross-subsidies and inefficient incentives. In particular, if consumers do not face the true time-varying cost of consuming electricity, they have too much incentive to consume at peak times and too little incentive to shift usage to off-peak times.

5 An Equitable Opt-In Dynamic Tariff

A significant source of opposition to dynamic tariffs is that they are perceived as punishing the customers by charging high prices just when the customer needs the power most. Of course, if those high prices reflect truly high costs, then these costs aren't avoided by charging flat rates for power; payment is just shifted away from peak hours and spread over all hours. In fact, those costs are exacerbated, because the failure to raise retail prices at peak times undermines the normal demand response when supply is limited and the wholesale price rises. To make dynamic prices appealing on equity grounds, it has to be made clear that high peak prices aren't avoided through flat retail tariffs.

An opt-in dynamic tariff is likely to achieve greater actual and perceived equity if both the dynamic tariff and the flat-rate tariff are based on the same publicly posted underlying costs. To begin, the utility, the regulator and other parties could agree on a dynamic retail tariff that would be revenue-adequate if all customers were on it. Ideally, this tariff would reflect true marginal costs during each period or at least reflect marginal cost differentials across periods, but that is not critical for the implementation and it may not be possible to reflect marginal costs exactly given the long-run break-even requirements of the utility.

To fix ideas, let us assume that costs are deemed to be fairly approximated by a CPP rate with an off-peak, peak and critical peak price per kWh, p_{op}, p_p and p_{cp}. For those who opt in to the dynamic rate, they would face these prices during the relevant periods. For those who choose not to opt in, they would face a flat rate $p_f = \alpha_{op} p_{op} + \alpha_p p_p + \alpha_{cp} p_{cp}$, where $\alpha_{op} + \alpha_p + \alpha_{cp} = 1$. The α weights are the shares of the total consumption *by the entire flat-rate pool of customers* that occurs within each of the three rate periods. If historical hourly consumption data were available for each customer—which will be the case if there is a significant lag between installation of smart meters and any large-scale dynamic residential pricing program—then the utility could estimate p_f fairly precisely once it knew which customers had opted to join the dynamic rate and which had not. If such historical load pattern data were not available at first, then p_f could initially be set at the previous flat rate until sufficient load data were collected. In either case, this approach requires that the utility have access to actual load pattern data of customers in each group, which is now becoming possible with smart meters.[9]

Fundamentally, this approach bases the rates for all customers on the same underlying price structure: the dynamic price structure that reflects the costs of the utility. Customers who opt in face that structure directly. All customers, however, continue to have the option to be part of a group of customers that form a sort of "flat rate" insurance pool: individually each customer in the pool pays the same flat rate regardless of his or her consumption pattern, but in aggregate this group of customers pays a total revenue that covers the groups' pattern of electricity consumption as if it were charged under the dynamic rate.

As with insurance, the costs paid by the two groups will be influenced by both selection effects and incentive effects. The selection effect would manifest as customers with relatively lower consumption at peak (and critical peak) times disproportionately opting in to the dynamic rate, while those who consume a greater share of their total consumption during peak times would disproportionately opt to stay on the flat rate. The incentive effect would result in those who opt in to the dynamic rate achieving savings by shifting consumption out of peak periods, while those who choose the flat rate would have no incentive to shift their load.

This opt-in approach does not raise the coercion issues of a mandatory or opt-out dynamic tariff. It has the equity and credibility appeal that all consumers face the same publicly posted underlying rates. Some choose to be in the opt-in group that pays those rates directly while others choose to be in the default group that pools consumption of the group across all hours and customers in the group, and pays the average rate for the default group as a whole. Customers in the default group are protected from price

[9] Some systems may allow customers to opt out of receiving a smart meter, which would eliminate their opportunity to participate in time-varying pricing. Implementation of this approach, however, requires only that the utility can accurately estimate the *aggregate* load pattern of those who do not opt in to time-varying pricing. Utilities have done this in most or all areas with retail choice by collecting real-time consumption data on a stratified random sample of households.

volatility, but they give up the ability to reduce their bills by shifting consumption across hours.

In practice, the selection effect at first is likely to be more significant than the incentive effect in determining electricity bills. Households with flatter load profiles—due to household demographics, work schedules, local weather, or other factors—are more likely to opt in and the opt-in group is quite likely to pay a lower overall average price than do the customers in the default group. Still, any customer has the option of choosing to be in either group. Over time, the incentive effect will at least partially offset the impact of selection on the default group. As customers on dynamic rates respond to peak prices, the system operation becomes more efficient and the utility's cost per kWh falls. Those system operation savings can be shared by all of the utility's customers.[10]

In theory, the selection effect can be so strong as to create an "unraveling": the flat rate rises as customers with lower-cost load profiles shift to the dynamic rate, which causes the dynamic rate to be economic for a larger share of customers, which causes still more to switch to the dynamic tariff, which raises the flat rate further as the population still on the flat rate becomes a set of customers with ever higher-cost load profiles. In Borenstein (2005b), I referred to this as the virtuous cycle by which the unwinding of the current cross-subsidy (towards customers who consume disproportionately at peak times) yields stronger incentives to switch to the dynamic rate and further isolates the highest-cost customers on the flat rate.

In practice, this unraveling may not boost the adoption of dynamic tariffs very much. As I show later, the bill change from a switch to the dynamic tariff may not be very large even for customers with fairly flat load profiles, so many may choose to skip the small expected gain. Of course, if those customers can also respond by lowering their consumption at peaks times, then their savings could be substantially enhanced. That sort of efficient response of consumption to prices, however, will tend to lower, not increase, the price for customers who remain on the default flat rate, as has been shown by Borenstein and Holland (2005).

5.1 Encouraging Positive Selection with Shadow Billing

Perhaps the greatest barrier to opt-in dynamic tariffs is low enrollment rates.[11] Customers are likely to stick with the default rate if they don't see tangible benefits that are available with the opt-in.

To better inform customers of their options, a straightforward technique that has now started to be used in many pilot programs is shadow billing. In this application, it means that every bill would include information about how much the customer would owe if she had been on the alternative tariff. This would be the case regardless of which tariff the customer chooses: a customer on the default rate would receive a bill that has an additional line saying something like, "If you had been on the opt-in dynamic

10 See Borenstein and Holland (2005).

11 Letzler (2010) reviews the literature and finds that even successful programs have enrollment rates around 1 %.

tariff, your bill this month would have been \$78.41" while a customer that has signed up for the dynamic tariff gets an additional line on his bill saying, "If you had been on the default flat tariff, your bill this month would have been \$78.41." In either case, the customer can compare his bill to what he would have owed had he been on the alternative rate schedule. For more information, the customer could be referred to a bill insert or to a website where the details of the tariff choices would be spelled out. The comparison will likely vary month-to-month and may be affected by seasons and weather. Thus, it would be valuable to add the same information for the last 12 months. When customers do switch, or when they consider switching, it will be important to inform them of how they can increase their savings by shifting consumption away from high-price periods.

Shadow billing has another value in addressing concerns about bill shock: Bills under the dynamic tariff will be more volatile, as I show empirically later. If a customer is exposed to shadow bills for some period of time before going on the opt-in tariff, he will see that volatility. That might be enough to discourage him from opting in, which would be the efficient choice if the volatility is truly costly. Still, it also might allow the customer to see that the volatility may lead to surprisingly high bills in some months, but leads to lower bills in most months and overall leaves him better off. That is likely to reduce distress if the customer does opt in to the dynamic rate and then receives an unusually high bill.

5.2 Addressing Bill Volatility: Hedging and Borrowing

Even if customers are relatively well informed and choose to opt in to dynamic pricing, they will still face increased bill volatility. As discussed later, the increase in volatility from a CPP tariff may not be great enough to create significant adverse reaction, especially given that all participants have opted in. Still, some customers will not be that well informed even after the efforts of the utility, and well-informed customers might still be put off by the increased volatility and might choose not to enroll. Thus, strategies for reducing the impact of bill volatility are still relevant.

The most obvious strategy from an economic point of view is hedging. With a CPP program, hedging could be done fairly simply, though even a very simple hedge strategy may still be more complex than the typical customer can understand or wants to deal with.

The straightforward hedge for customers on CPP would be for them to purchase fixed-quantity peak-period electricity contracts at a fixed price—a price that is slightly higher than the peak-period price and much lower than the critical-peak price—which cover all peak periods, both critical peak and not (because no one knows which days will be a critical peak at the time that the contract is signed). Such a fixed-quantity hedge contract would supply, for example, 12 kWh during the peak period for every non-holiday weekday of the summer period. For peak periods in which no critical peak is called, this has a slight negative impact on the customer since she is buying some fixed quantity of power at a higher price than the peak retail price she would otherwise face. For critical-peak periods, this has a positive effect for the customer because she has pre-purchased some power for the day at a price that is much lower than the price she would otherwise face. In both cases, the customer pays the CPP tariff rate (peak price if it is a normal day, critical peak price if it is a critical peak day) for any power consumed above the hedge quantity and is rebated at the CPP tariff rate for any excess power in the hedge contract that she doesn't consume. Thus, the marginal incentive to consume is the same as for customers on CPP who do not hedge.

The main question in such hedge contracts would be the quantity that a household should hedge. If the goal is to minimize bill volatility, the customer would probably want to hedge at least 100 % of her average peak-period consumption if her consumption is positively correlated with the price, i.e., if she consumes more on critical-peak days than on days with a normal peak period.[12] Unfortunately, if consumers don't distinguish clearly between the average price that they pay and the price that they face on the margin, such hedging is likely to reduce the impact of the price increase on critical-peak days.[13] Even if they do understand the distinction, hedging activity of this sort may seem like more effort than is warranted given the limited risk.

That doesn't mean that a low-hassle protection against unanticipated bill spikes would not have appeal. One type that is already offered by most utilities goes by "Balanced Payment Plan," "Level Pay Plan" or similar terms. These plans estimate the customer's expected bill over the year and require payment each month of the estimated average bill rather than the actual bill for that month. These programs have some true-up mechanism—in some cases at the end of the year, in other cases periodic adjustments when actual consumption deviates too much from predicted consumption—so that the customer ends up paying the same as she would have without the plan. While these plans do help to smooth payments for cash-constrained customers, they also probably reduce the salience of energy bills—particularly the causal impact that the actual bill liability incurred could have on behavior—and thus might lead to less efficient consumption behavior.

An alternative plan might be able to capture the payment smoothing without losing the bill salience. Rather than an automatic bill smoothing, this approach, which I will call a "SnapCredit" plan, would kick in only if a customer had an unusually high bill. Essentially, a SnapCredit plan would automatically offer to allow the customer to defer paying the unusually high component of the bill. The deferred payment would then be spread over the next 6 or 12 months. Each month the customer would still receive a bill for the energy consumed that month, which indicates the cost that will eventually have to be paid. But if the bill were more than a certain amount above the expected bill for that month (using basically the same tools that are currently used to calculate expected bills for plans like Level Pay), the bill would include an offer of the SnapCredit option to pay only the expected amount and to have the remainder spread out over some number of months in the future. The utility could charge interest or not, though most Level Pay plans do not charge interest.[14]

Like the Level Pay plans, the SnapCredit plan would help consumers who are surprised by a higher-than-expected bill in 1 month and do not have the financial cushion

12 Borenstein (2007a) discusses optimal hedging when consumption quantity is correlated with price.

13 "I don't need to adjust my thermostat since I've already purchased most of the power I need today."

14 Letzler (2010) presents an alternative approach that in effect has customers by default save up for CPP days and then draw down on those savings to reduce bill shocks when CPP calls occur.

to manage the shock. Unlike the Level Pay plan, this would not create a general cognitive disconnect between consumption and payment. The full bill would still be presented as the default payment, so the customer's attention would still be focused first on that liability. But the consumer would have the option to spread out payments on the component of the bill that is higher than expected. To exercise the SnapCredit option, however, the consumer would have to take an action in order to choose a payment that is lower than the full bill. This would reduce the loss of salience that results from the Level Pay plans, but would still address the problem of bill shock.[15] There is no reason to limit this approach to customers on a dynamic tariff, but it would be helpful in addressing the concerns that the dynamic tariff will result in volatile bills—particularly, under CPP, in the months in which multiple critical peaks are called on very hot days.[16]

5.3 Dynamic Pricing and Increasing-Block Tariffs

In many parts of the country—probably more in California than anywhere else—a major barrier to time-varying pricing is the pre-existing complexity of retail tariffs. In particular, about one-third of US utilities use an increasing-block pricing (IBP) schedule in which the marginal price per kilowatt-hour increases with the customer's consumption quantity during a billing period.[17] Among customers of California's three large investor-owned utilities, the price on the two top tiers (which is the marginal price for about the highest-use one-quarter of residential customers) is nearly three times the price on the lowest tier (which is the marginal price for about the lowest-use one-third of consumers). The differential pricing under IBP has no cost basis; it has been supported based on the beliefs that it encourages conservation and that it benefits low-income customers. Ito (2012) demonstrates that it probably has about zero net impact on total consumption. Borenstein (2012) shows that it does result in a modest average savings for low-income customers, about $5 per month after accounting for other subsidies to poor households.

IBP also complicates implementation of time-varying pricing. The two largest California utilities have taken different approaches to this issue in their small opt-in TOU pricing programs. PG&E has implemented a fairly complex tariff that combines TOU and IBP by creating separate IBP tariffs for peak and off-peak consumption. The exact points of consumption at which the marginal price increases, however, depends in part on the share of the customer's consumption that is during peak and off-peak periods, and these shares change with every billing period. The result is a tariff that

15 In practice, a SnapCredit program would look a lot like a credit card payment plan in which the customer has the option of paying off the full liability or carrying a loan into the next period, though the utility would probably offer lower interest rates than do credit card companies.

16 Both hedging and SnapCredit could be used indefinitely to reduce bill volatility. Utilities already use "bill protection" to reduce the customer's risk from switching to a new tariff. Under bill protection, the utility caps the customer's bill under the new tariff at the bill that they would have owed under the old tariff. This structure undermines the price incentives to some extent and it necessarily reduces the utility's revenue, so it is used only as an aid to transition, typically for the first year on the new tariff.

17 Borenstein (2012) analyzes in detail the efficiency and equity issues that are associated with such pricing.

both the utility and the regulator recognize as hopelessly confusing. SCE dropped the IBP concept entirely for its opt-in TOU rate, but it maintained it for its default rate that is not time-varying. As documented in Borenstein (2007c), this created perverse incentives for any large customer to avoid the high prices on the highest IBP tiers by switching to the TOU rate, while making the TOU rate completely uneconomic for any small customer.

Nonetheless, it is worth pointing out that time-varying pricing can be combined with IBP. PG&E's SmartRate tariff is a good illustration of how it can be done. Rather than time-varying retail prices in the basic tariff, the time-variation is designed as a revenue-neutral set of rebates and surcharges that can be considered independent of the underlying tariff. Off-peak periods have rebates that are paid with every kilowatt-hour that is used in those periods, while peak and critical peak periods have surcharges.

To follow the concept of the equitable opt-in dynamic pricing tariff that I have described, however, it would be very important that the rebates and surcharges should be set so that they would be revenue-neutral *if* all customers signed up for the program. In practice, customers with flatter load profiles will volunteer in greater numbers, which means that this program will run a deficit. That deficit would then be offset not by changing the rates for the rebate/surcharge program, but by raising the rates of the basic electricity tariff.

The accounting for this program can be (and in PG&E's case is) done entirely separately from the underlying IBP tariff. This doesn't remedy the distortions introduced by IBP, but it shows that IBP need not be a complete barrier to introducing more economic pricing.

5.4 Opt-In Dynamic Pricing and Retail Direct Access

The tariff design that I study here assumes a single monopoly utility supplier. In parts of the US, however, residential customers are able to choose a retail energy supplier that is different from the local distribution company. Competitive retail suppliers are free to price with whatever time variation they want, though most have primarily offered flat-rate tariffs.

In most such areas, there is still a dominant regulated incumbent utility that offers retail power. That utility is usually the default provider and the provider of last resort if no other seller can reach a mutually agreeable contract with the customer. In such situations, the pricing approach described here could still be used by the incumbent utility. In fact, such an approach would make the incumbent utility less vulnerable to "cherry picking" by competitive retailers than under a single flat-rate tariff. If the utility offers only a flat-rate tariff with no option for time-varying pricing, retail competitors may be particularly interested in acquiring customers with less-expensive consumption profiles. Whether competitors actually have such an incentive depends on whether the retailer is required to obtain power to match the *actual* time-varying consumption pattern of its customers or just a standardized consumption profile that is assumed for all residential customers. Presumably, if the technology is in place to allow the incumbent to bill on a time-varying basis, then competitive retailers would be able to do the same.

5.5 Impact on Low-Income Customers

One of the most frequent policy concerns about dynamic pricing is the impact that it will have on low-income customers. Of course, no pricing policy change will have a uniformly positive or negative impact on poor households. Within that group of customers there will be some winners and some losers. An opt-in dynamic tariff with a default flat rate has two potential types of losers. Those who stay with the flat rate are likely to see an increase in that rate as customers who consume less on-peak disproportionately switch to the dynamic tariff. This increase, the result of ending the current cross-subsidy of consumption at peak times, would probably be quite modest, as is shown in the next section. Whether it would disproportionately impact rich or poor customers is hard to know. A good starting point, however, is to ask whether the poor typically consume a larger share of their power during peak periods. As discussed below, the answer seems to be that in this dimension the poor are not very different from the rest of residential customers.

The second set of potential losers are those who opt in to dynamic pricing and find that they have costly load profiles so that they would have been better off staying on the flat rate. Shadow billing seems likely to be an effective mechanism for informing such customers of their mistakes, either before they switch or after. A plan like SnapCredit may help customers deal with mistakes in the short run while still making clear the full cost of the chosen plan and alternative. The combination of shadow billing and SnapCredit wouldn't eliminate all concerns about customer mistakes, but it seems likely to make them less common and less costly.[18]

6 Empirical Investigation of Bill Changes Under Dynamic Pricing

In order to study the likely magnitudes of the policies and responses discussed above, one needs to know the demand patterns of households. To pursue this issue, the U.C. Energy Institute obtained access under confidentiality agreements to the load research data that PG&E and SCE have collected on stratified random samples of residential customers for many years. The data made available to UCEI cover 2006–2009 for PG&E and 2004–2008 for SCE.

The data include hourly consumption of each customer. The only other information in the dataset is the approximate location of the premise (9-digit Zip Code or census block group), the rate schedule the premise is on and whether it is a single-family or multi-family dwelling. The data are cross-indexed to general population demographic categories—by climate area/average daily usage category/dwelling type—in order to develop observation weights that make the sample reflective of the population as a whole. The data also include ID numbers that allow matching of the same premise across days. The number of premises tracked varies year-to-year ranging from 859 in

[18] And bill protection, as described earlier, can protect customers during the transition period from paying more under the new tariff.

2006 to 1034 in 2009 for PG&E and 2,761 in 2004 to 2,845 in 2008 for SCE. Some premises drop out and others are added over time.[19]

Because the data are stratified random samples that oversample some categories of customers relative to others, weighting observation is important in studying population average effects. All of the results reported here are based on use of all premise-years in the data in which a premise's average consumption is at least 1 kWh/day. For each year, the included premises are then weighted to be representative of the premise shares within each climate area/average daily usage/dwelling type category in the entire population. Results are very similar doing the same analyses using only premises that are missing in no more than 30 days out of all days in each utility's sample, and appropriately re-weighting observations.[20] An observation is a premise-year in the statistical analysis I report. All statistical tests report clustered observations from the same premise to avoid understating standard errors.

6.1 Hypothetical Critical-Peak Pricing, Time-of-Use and Flat Tariffs

In order to analyze the switch from a flat tariff to time-varying alternatives, I create for each utility dataset revenue-neutral alternatives to the flat rate, under the assumption of zero price elasticity. Obviously, this ignores the potential behavioral changes that time-varying tariffs encourage. It also ignores the fact that in reality these customers are on increasing-block tariffs, which vary depending on region and whether the customer has electric heat. In addition, some of these customers are already on a TOU tariff. Less than 1 % of customers are on TOU for both utilities, but they are greatly over-sampled in PG&E, making up 10 % of households in the load research data. The weighting corrects for this over-sampling.[21] Below, I incorporate demand elasticities, but consistent with my own previous work, and demand elasticity estimates by others, this does not significantly change the distributional impact analysis.[22]

[19] Premises stay in the dataset even when the occupant changes. Thus, I am assuming the basic characteristics of the premise occupants doesn't change when the occupant changes. Two premises were dropped from the PG&E data. The consumption reported for these two customers was many times higher than all other customers. It is not clear if these are estates, if these customers also have commercial operations, or if these are data errors. The results would be slightly skewed by these two households and it would be difficult to report data by segments without potentially revealing information about these households.

[20] Results change somewhat, though the basic conclusions remain the same, if all observations are equally weighted, though such analyses end up substantially over-representing some regions and types of customers.

[21] Throughout the analysis I also ignore the fact that about 20–25 % of the customers are on CARE rates, which are reduced rates for low-income customers. Consumption patterns of this group do not seem to differ from other low-income customers, as is indicated by the statistical matching methods below. Still, the existence of the CARE program serves as a reminder that special protections could be given to low-income customers who opt in to a dynamic tariff.

[22] See Borenstein (2007b) and Borenstein (2012). Longer run demand elasticities may be somewhat higher than analyzed in these papers, but those estimated long-run elasticities are based on general rate level changes, not for the short-term price variation of dynamic pricing. The elasticities that are implied by analyses of, for instance, the California Statewide Pricing Pilot, as well as programs in Anaheim and Washington, D.C., are consistent with those simulated in my earlier distributional studies. See Faruqui and George (2005), Herter et al. (2007), Letzler (2009) and Wolak (2006, 2010).

Table 1 Hypothetical tariffs

	Winter peak	Winter off-peak	Summer critical-peak	Summer peak	Summer part-peak	Summer off-peak
PG&E						
Flat rate	\$0.160	\$0.160	\$0.160	\$0.160	\$0.160	\$0.160
TOU	\$0.149	\$0.129	\$0.354	\$0.354	\$0.216	\$0.124
CPP	\$0.142	\$0.123	\$0.800	\$0.335	\$0.205	\$0.118
SCE						
Flat rate	\$0.160	\$0.160	\$0.160	\$0.160	\$0.160	\$0.160
TOU	\$0.145	\$0.126	\$0.344	\$0.344	\$0.210	\$0.121
CPP	\$0.136	\$0.118	\$0.800	\$0.322	\$0.196	\$0.113
Effective	Nov–Apr	Nov–Apr	May–Oct	May–Oct	May–Oct	May–Oct
	Mon–Fri	All other	M–F, 1pm–7pm	Mon–Fri	Mon–Fri	All other
	5 pm–8 pm Except holidays	Winter hours	15 days of Max demand of summer	1pm–7pm Except holidays and CPP days	10am–1pm and 7pm–9pm Except holidays	Summer hours

I start from a systemwide flat rate for residential customers of \$0.16/kWh, which was the approximate rate in 2006. I then create a time-of-use rate that results in the same total revenue over the full sample as under the flat rate for the (weighted) stratified sample and the same price *ratios* between TOU periods. For both utilities, I set the peak, off-peak and shoulder times as shown in Table 1.[23] This is intended to be a fairly representative TOU tariff, though it does not exactly match the timing of the PG&E or SCE rates. The rates and time periods are shown in Table 1.[24]

To create hypothetical CPP tariffs, I start from the hypothetical TOU rates and then identify the 15 highest-demand days of the year in the California ISO system for each year based on the day-ahead forecast of demand, because CPP days generally are called on the prior day. Those are designated as CPP days and the price is set to \$0.80/kWh for the peak period on those days, which are all during the summer tariff period. All other rates are readjusted downward to maintain revenue neutrality and maintain the price ratios between all other periods. The CPP rates are also shown in Table 1. Under the zero-elasticity assumption, I then calculate the bills of each customer for each month under TOU, CPP and the flat rate.

This is clearly not a perfect simulation of the CPP tariff. The days that are actually called as CPP may not turn out to be the 15 highest-demand of the year (based on day-ahead forecast), because the utility has imperfect information about the weather for the remainder of the year when it makes a CPP call. Below I consider the problem

[23] The rates shown are set to be revenue-neutral under the stratified sample weighting that includes all premises, as described above. The TOU and CPP prices are slightly different when the sample is limited to those premises for which there are data on nearly all days.

[24] PG&E differs in that it also has a Saturday shoulder period. SCE differs in that its summer critical peak that is used for peak-time rebates is only 2–6pm on weekdays. I use the PG&E summer CPP period, May 1 through October 31.

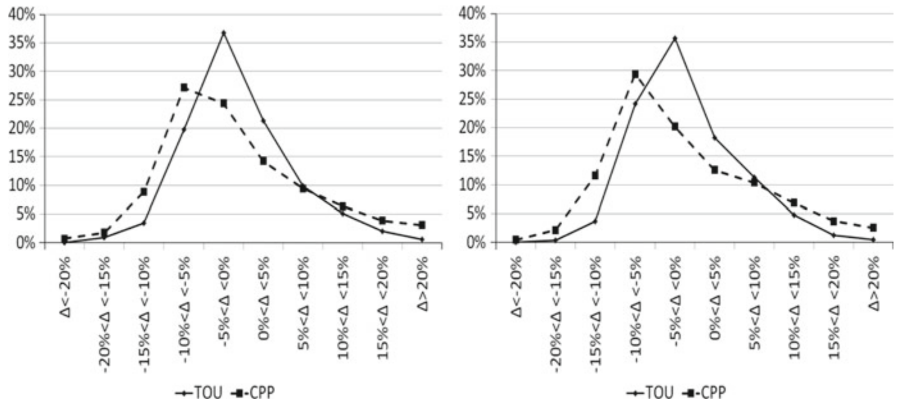

Fig. 1 Distributions of annual bill change from flat-rate to mandatory TOU or CPP

of calling CPP days when there is uncertainty about future weather and a fixed number of days to be called each year. I am also ignoring the issue of increasing-block pricing (IBP), which was discussed earlier.

6.2 Winners and Losers Under Mandatory TOU and CPP Pricing

While it will likely be many years, if ever, before mandatory time-varying pricing is implemented for residential customers, it is still a useful starting point to examine how such a change would affect customers. Besides suggesting the impact of a mandatory time-varying tariff, it also sheds light on the incentives that customers would have under an equitable opt-in dynamic tariff as described earlier. Figure 1 shows the overall distribution of rate changes across customers of PG&E and SCE. Most notable is the relatively narrow range of bill changes. For PG&E with no demand response to the change in rates, 96.2 % of customers would see their bill in a given year change by less than 20 % up or down under CPP as compared to a flat rate: 3.1 % would see an increase of more than 20 and 0.7 % would see a decrease of more than 20 %. The figures are about the same with SCE: 96.9 % of customers would see their bill change by less than 20 % up or down under CPP, 2.6 % would see an increase of more than 20 and 0.5 % would see a decrease of more than 20 %. Not surprisingly, the changes are less dispersed under TOU.

Table 2 displays the average change that would result from CPP by location, average usage and income.[25] Not surprisingly, coastal areas would benefit since they consume a smaller share of their power on hot summer days. The further east one goes within each utility's territory the more the mandatory CPP program modeled here would

[25] These average changes in the percentage bill are weighted by the premise's daily usage, so higher-use households within each category are weighted more heavily. This corresponds approximately to the change in the aggregate consumption of premises in the category. It avoids the representation that the average household in every income category saves money, which is driven by the fact that low-consumption households are more likely to save money.

Table 2 Distributions of average annual bill change by region, usage and income

Region		Daily average usage (kWh)		Household annual income (random rank method)		Household annual income (usage rank method)	
PG&E							
Coastal	−6.9 %***	Q < 9.5	−3.5 %***	I < $20K	0.5 %	I < $20K	1.6 %
Hills	−1.6 %***	9.5 < Q < 14.2	−2.2 %***	$20K < I < $40K	−0.1 %	$20K < I < $40K	−1.3 %
Inner valley	3.4 %***	14.2 < Q < 19.2	−0.8 %	$40K < I < $60K	0.2 %	$40K < I < $60K	1.4 %
Outer valley	6.0 %***	19.2 < Q < 28.7	2.0 %***	$60K < I < $100K	0.4 %	$60K < I < $100K	0.8 %
		Q > 28.7	0.4 %	I > $100K	−0.6 %	I > $100K	−0.1 %
SCE							
Coastal	−5.1 %***	Q < 9.2	−4.7 %***	I < $20K	−0.7 %**	I < $20K	−2.1 %***
Inland	2.9 %***	9.2 < Q < 13.5	−2.2 %***	$20K < I < $40K	−0.3 %	$20K < I < $40K	0.3 %
Desert	7.9 %***	13.5 < Q < 18.1	−1.6 %***	$40K < I < $60K	0.2 %	$40K < I < $60K	−0.7 %
		18.1 < Q < 25.2	1.0 %**	$60K < I < $100K	0.5 %	$60K < I < $100K	0.6 %
		Q > 25.2	1.6 %***	I > $100K	0.1 %	I > $100K	0.0 %

Percentage changes are weighted by the premise's daily usage, so higher-use households within each category are weighted more heavily. Region demarcations for each utility are available from the author upon request

*** significantly different from zero at 1 %, ** significant at 5 %, * significant at 10 %

raise bills. These average differences are all highly statistically significant. If it were politically desirable, this difference in average impact would be easy to offset with rate variation by location, or less-expensive baseline power (or higher baselines, as is done now) in the inland area.

The second column shows changes broken out by quintiles of average daily usage among the households in the load research data. Low-usage households consume a smaller share of their power at peak times which results in a more favorable impact from a switch to CPP. The pattern is statistically significant for both utilities. Still, the percentage differences are fairly small with the exception of about a 4 % average bill decline for the lowest-usage customers, and even that reflects a quite small dollar change in the monthly bill. This correlation with usage in part reflects the fact that low-usage households are more likely to be coastal, but that does not explain the entire difference. The difference across usage-level households remains statistically significant even after controlling for average region differences. High usage households still see bill changes that are about three percentage points higher than the lowest usage households.[26]

The third and fourth columns present results from two different approaches to matching of households in the dataset to income brackets. The typical approach to such questions has been to assign to each household the median household income of the census block group (CBG) in which the household resides, but Borenstein (2012) shows that there is a great deal of heterogeneity within CBGs. Borenstein (2012) presents two different approaches to handling this heterogeneity. The first approach randomly assigns households to income brackets within the CBG. This "random rank" method incorporates the distribution of income within the CBG, but implicitly assumes that there is no correlation between income and the variable of interest, in this case the bill change that results from a shift to dynamic pricing. The second approach rank orders households by a predictor variable—in this case, electricity consumption—and then allocates households to the income brackets in ascending (or descending, depending on the believed correlation) order. This "usage rank" approach almost certainly overstates the correlation between income and electricity usage. Under either approach, each premise is assigned to one of five income brackets that are approximately quintiles. As Table 2 shows, neither approach suggests that a change to CPP would substantially alter the average electricity bills of households in the lowest income brackets. In fact, for all of the income brackets, the estimated average change is 2.1 % or less and most are under 1 %.[27]

The result does not appear to support the common view that lower-income customers have substantially less peaky load profiles, at least in the service territories

[26] This is based on regressions of the percentage bill change on dummy variables for each climate region and all usage categories except the lowest. For both utilities, an F-test of the usage category dummy variables rejects pooling across the categories. For SCE, the two highest-usage categories are estimated to average 3.5 % (next-to-highest category) and 3.2 % (highest category) higher bill changes than the lowest category, both significant at 1 %. For PGE, the differences are estimated to be 2.2 % (significant at 1 %) and 0.4 % (not statistically significant), respectively.

[27] Households are matched to CBGs based on their 9-digit Zip Code. Of the 2845 SCE premises, 130 have only 5-digit Zip Code information. For these premises, the same procedure as described here was used, except at the 5-digit Zip Code level.

of these two utilities. In fact, it appears that the average impact is close to neutral for households in all five income brackets. By region, however, the story is slightly more consistent with the common view. Wealthier customers in both utilities' territories live disproportionately on the coast. After controlling for climate regions, the lowest-income bracket does better than the wealthiest. The difference is statistically significant in SCE territory, but the difference is only 1.5–2.5 %. Estimates for PG&E indicate a difference of less than 1 % and are still not statistically significant. Overall, there seems to be very little systematic relationship between household income and the impact of CPP.[28] These results contrast with those of Faruqui et al. (2010), who find that low-income customers have less peaky demand than other customers. The authors, however, don't disclose where the "large urban utility" that they study is located or whether there is a correlation between climate and household income within that utility's service territory. Horowitz and Lave (2012) study the impact of a real-time pricing program in Chicago. They find that low-use customers have peakier demand than others and are more likely to be made worse off under RTP. This seems to be primarily a result of the fact that high-use customers in the area they study are wealthier and are disproportionately using electric space heating, which results in a flatter load profile.

6.3 Incorporating Demand Response

Incorporating demand elasticity in response to time-varying prices has the anticipated effect of making dynamic pricing more attractive. Results similar to Table 2, but presenting changes in consumer surplus (as a percentage of the flat-rate bill) rather than bills, are shown in the Table 3 for elasticities of 0, −0.1 and −0.3. In the short run, it seems unlikely that the elasticity of demand is larger than −0.1 (in absolute value) in response to time-varying prices, but as technology for price-responsive demand improves, including more automated demand adjustment in response to prices, the −0.3 elasticity might be a better guide.

To calculate the impact of demand elasticity, I assume that each premise, i, has a demand in each hour h of $q_{ih} = a_{ih} p_h^{\epsilon}$. The parameter a_{ih} is inferred from the premise's actual consumption in the hour on the assumption that they faced the flat rate of \$0.16/kWh. Their change in quantity consumed and consumer surplus as prices change is then calculated along the constant-elasticity demand curve.

Implicitly, this calculation assumes that changes in quantity in response to the CPP rate impose marginal costs that are exactly equal to the CPP rate in that hour, so the change in quantity does not require a tariff change in order to hold constant the profit level of the utility. The assumption is not entirely benign—reducing peak demand would likely lower long-run marginal cost at peak times and might raise long-run marginal cost off peak—but it is a reasonable starting point for this calculation.

The impact of −0.1 elasticity is fairly modest: The average consumer surplus of nearly all categories increases by between 1 and 2 % of the flat-rate bill. The impact of

[28] These changes are also small enough that even small changes in behavior on average would cause the average bill in every income bracket to decline.

Table 3 Distributions of consumer surplus changes incorporating demand response

Region		Daily average usage (kWh)		Household annual income (random rank method)		Household annual income (usage rank method)	
Elasticity = 0							
PG&E							
Coastal	6.9 %***	Q < 9.5	3.5 %***	I < \$20K	−0.5 %	I < \$20K	−1.6 %
Hills	1.6 %***	9.5 < Q < 14.2	2.2 %***	\$20K < I < \$40K	0.1 %	\$20K < I < \$40K	1.3 %
Inner valley	−3.4 %***	14.2 < Q < 19.2	0.8 %	\$40K < I < \$60K	−0.2 %	\$40K < I < \$60K	−1.4 %
Outer valley	−6.0 %***	19.2 < Q < 28.7	−2.0 %***	\$60K < I < \$100K	−0.4 %	\$60K < I < \$100K	−0.8 %
		Q > 28.7	−0.4 %	I > \$100K	0.6 %	I > \$100K	0.1 %
SCE							
Coastal	5.1 %***	Q < 9.2	4.7 %***	I < \$20K	0.7 %**	I < \$20K	2.1 %***
Inland	−2.9 %***	9.2 < Q < 13.5	2.2 %***	\$20K < I < \$40K	0.3 %	\$20K < I < \$40K	−0.3 %
Desert	−7.9 %***	13.5 < Q < 18.1	1.6 %***	\$40K < I < \$60K	−0.2 %	\$40K < I < \$60K	0.7 %
		18.1 < Q < 25.2	−1.0 %**	\$60K < I < \$100K	−0.5 %	\$60K < I < \$100K	−0.6 %
		Q > 25.2	−1.6 %***	I > \$100K	−0.1 %	I > \$100K	0.0 %
Elasticity = −0.1							
PG&E							
Coastal	7.9 %***	Q < 9.5	4.7 %***	I < \$20K	0.8 %	I < \$20K	−0.2 %
Hills	2.9 %***	9.5 < Q < 14.2	3.5 %***	\$20K < I < \$40K	1.6 %***	\$20K < I < \$40K	2.6 %**
Inner valley	−1.8 %***	14.2 < Q < 19.2	2.1 %***	\$40K < I < \$60K	1.1 %**	\$40K < I < \$60K	0.1 %
Outer valley	−4.3 %***	19.2 < Q < 28.7	−0.5 %	\$60K < I < \$100K	1.4 %***	\$60K < I < \$100K	0.6 %
		Q > 28.7	1.0 %*	I > \$100K	1.6 %***	I > \$100K	1.5 %***

Table 3 continued

Region		Daily average usage (kWh)		Household annual income (random rank method)		Household annual income (usage rank method)	
SCE							
Coastal	6.3 %***	Q < 9.2	6.0 %***	I < $20K	2.4 %***	I < $20K	3.6 %***
Inland	−1.2 %***	9.2 < Q < 13.5	3.7 %***	$20K < I < $40K	1.8 %***	$20K < I < $40K	1.3 %***
Desert	−5.9 %***	13.5 < Q < 18.1	3.1 %***	$40K < I < $60K	1.5 %***	$40K < I < $60K	2.3 %***
		18.1 < Q < 25.2	0.6 %	$60K < I < $100K	1.1 %***	$60K < I < $100K	1.0 %**
		Q > 25.2	0.0 %	I > $100K	1.4 %***	I > $100K	1.5 %***
Elasticity = −0.3							
PG&E							
Coastal	9.6 %***	Q < 9.5	6.8 %***	I < $20K	3.7 %***	I < $20K	2.3 %*
Hills	5.2 %***	9.5 < Q < 14.2	5.7 %***	$20K < I < $40K	3.7 %***	$20K < I < $40K	4.9 %***
Inner valley	1.0 %**	14.2 < Q < 19.2	4.5 %***	$40K < I < $60K	3.3 %***	$40K < I < $60K	2.7 %***
Outer valley	−1.2 %**	19.2 < Q < 28.7	2.2 %***	$60K < I < $100K	3.8 %***	$60K < I < $100K	3.2 %***
		Q > 28.7	3.5 %***	I > $100K	4.3 %***	I > $100K	3.9 %***
SCE							
Coastal	8.7 %***	Q < 9.2	8.3 %***	I < $20K	5.0 %***	I < $20K	6.2 %***
Inland	2.0 %***	9.2 < Q < 13.5	6.3 %***	$20K < I < $40K	4.7 %***	$20K < I < $40K	4.1 %***
Desert	−2.5 %***	13.5 < Q < 18.1	5.8 %***	$40K < I < $60K	4.4 %***	$40K < I < $60K	5.0 %***
		18.1 < Q < 25.2	3.5 %***	$60K < I < $100K	4.0 %***	$60K < I < $100K	3.9 %***
		Q > 25.2	3.0 %***	I > $100K	4.3 %***	I > $100K	4.3 %***

Percentage changes are weighted by the premise's daily usage, so higher-use households within each category are weighted more heavily. Region demarcations for each utility are available from the author upon request

*** significantly different from zero at 1 %, ** significant at 5 %, * significant at 10 %

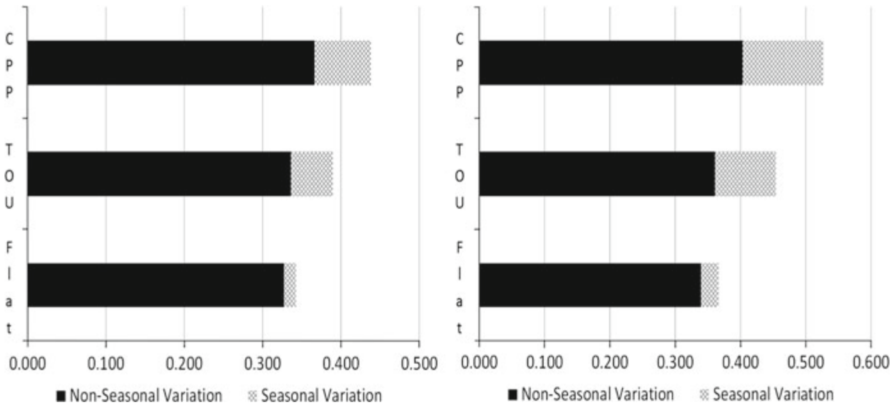

Fig. 2 Measures of monthly bill volatility under alternative tariffs

−0.3 elasticity is about three times larger in most categories. That would be sufficient to make the average consumer in all usage and income categories better off, as well as in all regions except the sparsely populated eastern-most regions of each utility's service territory.

This is not to suggest that all households would be winners from a shift to mandatory CPP. With no elasticity, the share of premises that are made better off in any given year by a switch to CPP is 63 % in PG&E territory and 64 % in SCE territory. With a demand elasticity of −0.3, those figures increase to 76 and 77 %, respectively, which still leaves nearly one-quarter of customers at least slightly worse off.

6.4 Bill Volatility

In addition to concerns about increases in a customer's overall cost of electricity, there is also concern about bill volatility under TOU and CPP rates. Some of the increase in bill volatility would be predictable: TOU and CPP rates are higher in the summer than the winter, which systematically increases summer bills and lowers winter bills. Some of the increased volatility is due to consumption shocks that are correlated with high-price periods. To examine the change in bill volatility—using households that are in the sample for at least 36 months—I estimate the volatility of each household's bills under the flat rate tariff, the TOU, and the CPP. The bars in Fig. 2 present the coefficient of variation in monthly bills under the alternative tariffs for each utility.[29]

The results show that just switching to TOU raises bill volatility substantially even though the rate is not dynamic. For PG&E, average bill volatility, measured by the coefficient of variation, increases 14 % with a switch from flat tariff to TOU. Going the next step to a CPP rate increases the volatility more: a 28 % increase over the flat

[29] To be precise, this is the estimated standard deviation (corrected for degrees of freedom) of daily average electricity cost in a month (to adjust for varying number of days) divided by the sample mean daily average electricity cost for each household.

rate. The changes are somewhat larger for SCE, increasing 24 % with a change to TOU and 44 % with a switch to CPP.

Bill volatility, however, can be decomposed into predictable seasonal variation and unpredictable—or at least less obviously predictable—variation. For each premise, I do this by regressing monthly bills under each tariff on month-of-year dummy variables to remove predictable monthly variation. After correcting for the degrees of freedom that are lost from the monthly dummy variables, the standard deviation of the residuals from these regressions represent the component of bill variation for that premise that is not predictable from the seasonal variation. The bars in Fig. 2 show the average values from this decomposition. While TOU and CPP do make bills more volatile, the decomposition shows that most of that additional volatility is the predictable effect of charging higher average rates during summer afternoons, when consumption is also higher on average. If the predictable volatility—the cross-hatched part of the bars—is removed, the difference is much smaller. For PG&E, TOU increases average residual bill volatility by 3 % over flat rates, while CPP increases residual volatility by 12 %. For SCE, the increase is 6 % under TOU and 19 % under CPP. These results suggest that the majority of bill volatility under CPP—and the great majority of unpredictable bill volatility—would be caused by quantity volatility, not by price variation. Even a flat-rate tariff doesn't eliminate the risk due to quantity volatility.

6.5 The Potential Impact of Opt-In Dynamic Pricing

As was explained earlier, if the flat rate for customers who don't opt in to dynamic pricing is set equitably, as defined earlier, the flat rate is likely to rise, because customers who don't opt in will disproportionately be those who consume more at peak times. The price for the group of customers who remain on the flat rate will increase due to this selection effect. There is also an efficiency effect that tends to lower the flat rate in the long run as capital adjusts, as shown by Borenstein and Holland (2005), but that effect may be small if the response of CPP customers to peak prices is modest. For this analysis, I focus solely on the selection effect, so this could be thought of as a worst-case scenario for the customers who do not opt in.

It's impossible to predict what share of customers will opt in at first and exactly what part of the distribution they will be drawn from, but experience suggests that most people will choose not to join, at least at first. Counterbalancing the potential savings is the higher bill volatility, and the hassle factor associated with switching tariffs or even having to think about electricity prices. In all likelihood—particularly if shadow billing is employed—those who opt in will disproportionately be customers with flatter load profiles, i.e., those who would gain from the mandatory CPP tariff examined in the previous subsection even if they don't change their behavior.

To get an idea of the potential impact on the flat-rate customers under the equitable tariff opt-in approach, I investigate the change in the default flat-rate tariff that would result with different assumptions about the customers who opt in. Based on the calculations in the previous section, it is straightforward to describe two boundary cases, one in which there is no selection effect and another in which there is a very strong selection effect. In the case of no selection effect—and continuing to assume no price

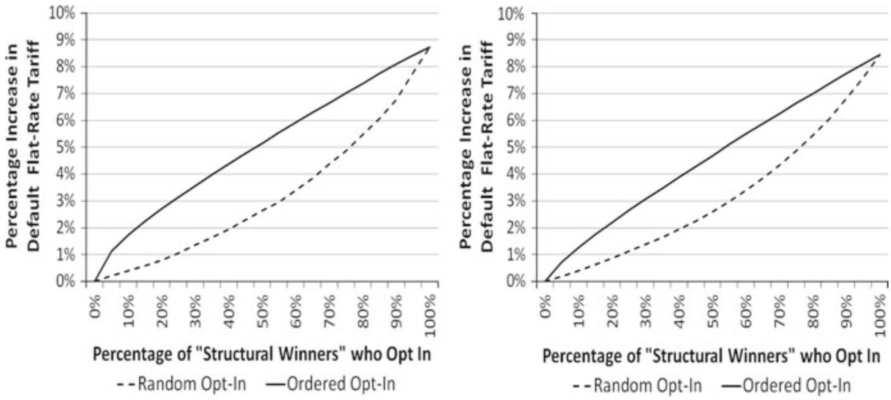

Fig. 3 Increase in the flat-rate tariff as more customers opt in to CPP

response—the customers opting in would on average have load profiles that are no more or less expensive than those who don't, so the cost of serving the remaining customers would not be changed, and the flat-rate tariff would not change.[30] A very strong selection effect would result in all customers with load profiles that are less expensive than average opting in to the TOU or CPP tariff. In that case, for PG&E the flat rate would increase by 6 % if the opt-in tariff were TOU and 9 % if the opt-in rate were CPP. The numbers are nearly the same for SCE.

In reality, with shadow billing, most of those who opt in will probably be from the group that is less expensive than average, but most of that group probably won't opt in, at least at first. To study the likely impact on rates, I examine cases that span a continuum of participation rates and two possible selections of participants. In both cases the set of people that join the CPP tariff are drawn entirely from customers who gain from switching without any change in behavior or change in the flat rate. These types of customers are often referred to as "structural winners" in the dynamic pricing literature. The dashed lines in Fig. 3 shows the change in the flat rate tariff that results as a given percentage of the structural winners, randomly chosen from among those who are structural winners, opt in to the CPP tariff. As more of this group opt in, there are fewer remaining on the flat rate to subsidize those with more expensive load shapes, so the flat-rate tariff must increase. If 100 % of structural winners opt in, the result is that the flat-rate increases by slightly less than 9 %.

The solid lines present a case with much greater selection among participants: participants opt in strictly in order of the monetary gains from doing so. If only a small share of customers participate, they are assumed to be the set of customers who have the very most to gain by doing so.[31] For any fixed percentage of structural winners (less than 100 %), this case of course causes a larger increase in the fixed-rate tariff than random selection among structural winners. This is obviously a very extreme case

[30] It is worth noting that more than one-third of the customers opting in in that case would be made worse off unless they changed their behavior. This seems very unlikely in the presence of shadow billing.

[31] To be precise, the order in which customers opt in is determined by the absolute dollar gain—not the percentage gain—from switching to CPP when the flat rate is at its original level (with no CPP participation).

and almost certainly overstates the impact on those who do not opt in. Yet, even in this case, the change in the flat-rate tariff is quite modest. Even if half of all structural winners switched to an equitable CPP tariff, and even if the half that opted in were heavily drawn from the largest structural winners, the increase in the flat-rate tariff would still likely be under 5 %.

As I've done throughout, this analysis ignores demand elasticity. It also ignores the "unraveling" effect that occurs as the increase in the flat rate puts additional customers on the side of winning from a switch to CPP even without changing their consumption pattern. The results in Fig. 3, however, suggest that the unraveling effect is likely to be quite small. For instance, if half of all structural winners opt in to a CPP rate, and they were a random selection from among the structural winners, then the flat rate tariff would rise by about 3 %, which would make about 8 % more of the customer population winners from switching. If half of those additional customers switched, the additional increase in the flat rate would be less than 0.1 % and the cycle would quickly peter out.

7 Alternative to a Fixed Number of CPP Calls

While critical-peak pricing may be a simpler way to make prices dynamic than a move to full real-time pricing, the simplicity comes at a cost. Two costs are the fixed price during critical peaks and the limited number of CPP calls that the utility can make each year.

The fixed CPP price means that the retail price cannot be adjusted to reflect more or less constrained periods among the CPP days. In some implementations, this constraint has been relaxed somewhat by allowing two different levels of CPP pricing. The utility can call a regular CPP day with a high price or an extreme CPP day with an even higher price. More pricing granularity would, of course, be attractive on grounds of economic efficiency, but the incremental gains may be limited if consumers don't make incremental adjustments in response to greater price granularity. Given the dearth of evidence on the impact of incremental price changes during CPP events, it is unclear how much is lost with a simpler pricing scheme.

The fixed number of CPP calls in a summer or year may be a more costly constraint. Generally, the policy gives the utility the right to call a CPP day *up to* a certain number of days per year—usually 10 to 15. The utility, however, usually needs to call the full number that is permitted in order to meet the revenue requirement that is allowed by regulators. Shortfalls can generally be made up in later years, but there is still interest on the part of the utility not to fall short of the planned number of calls. So, effectively, this rule leaves very little flexibility in the number of CPP days in either direction. If the utility knew in advance what the weather and other supply/demand factors would be for all days of the year, it would be easy for it to call critical peaks on the most constrained days.

But in reality the fixed number of calls creates a complex dynamic optimization problem for the utility. That optimization yields a trigger value for some indicator—such as system load or market price—each day that is a function of the number of remaining calls the utility has and the number of remaining days in which to use them, as well as demand and supply forecasts. The trigger value early in the period will reflect the expected distribution of system conditions for all future days of the period. As the days pass, the trigger value will rise or fall depending on how many calls have been made so far as well as any new information about future system conditions. The result of this dynamic optimization with imperfect information is that the X days per year that that utility ends up calling a CPP day will almost certainly not correspond to the X days of the year with the highest system load or price. Furthermore, even if the utility could identify the best days within a given year, the fixed number of days will be too many in some mild years and too few in some years with more extreme weather.

An alternate approach has been proposed, but to my knowledge it has not been implemented anywhere:[32] to "rebate" the excess revenue from a CPP call in hours surrounding the CPP period, while at the same time removing the prescribed number of calls. Instead of a prescribed number of calls, a threshold for CPP calls based on system conditions would be adopted.[33] The idea is that instead of the utility's revenue requirement relying on calling a fixed number of CPP days in a year, each CPP call would change prices in a way that is approximately revenue neutral. In this way, CPP calls could occur as frequently or infrequently as they are actually needed given system conditions, rather than according to a rigid prescription of days per year. As an example, every CPP call could automatically be followed by lowering prices by ΔP in off-peak hours for the following Y off-peak hours, where ΔP and Y are set to offset, in expectation, the excess revenue that is collected during a CPP call.[34]

While it seems likely that this would greatly improve the efficiency of CPP programs, there are two potential concerns. First, the efficiency gain from such an approach depends on there not being too deep a discount off-peak if that leads to inefficient overconsumption. There is, however, likely to be substantial opportunity for off-peak price reductions without inducing inefficient behavior. This is the case both because off-peak prices are generally well above the social marginal cost of power and because the inefficiency of mis-pricing increases with the square of the deviation from marginal cost, so dropping the price slightly below marginal cost induces deadweight loss that is second order.

Second, an unlimited number of CPP calls may make some customers hesitant to sign up. The utility would have to make clear that CPP calls are an opportunity to save by shifting usage and communication would have to be sufficiently effective that consumers are confident they will know when the calls occur. There is also an advantage in this area, however. The fixed number of calls can lead to utilities calling CPP days when the weather is mild and the system isn't very constrained, which reduces the program's legitimacy, engenders consumer backlash, and suggests a disconnect from the original purpose of the program. The unlimited calls would allow the utility to

32 Having asked numerous people who are concerned with dynamic pricing, I have been unable to learn the original source of this idea.

33 The threshold could be a mechanical rule or could permit some judgment on the part of the utility, subject to regulatory review.

34 Since the flat rate tariff is set prospectively based on expected load patterns of those on the flat tariff and costs, the flat rate would still be set based on a agreed-upon set of time-varying costs.

Table 4 PG&E SmartDays calls and actual day-ahead load forecasts

2009 Load			2010 Load			2011 Load		
Date	Forecast	Rank	Date	Forecast	Rank	Date	Forecast	Rank
7/21	263707	1	8/25	275127	1	9/7	258218	1
9/2	256820	3	7/16	274145	2	8/29	256127	2
8/28	256429	4	8/24	263469	4	9/8	251283	3
7/27	253427	6	9/27	263329	5	9/6	247142	5
8/27	253326	7	9/28	257326	6	7/5	246697	7
7/16	250509	10	7/15	255261	7	7/6	245076	9
7/14	250018	12	8/23	246427	8	8/18	238591	14
6/29	247251	17	9/3	244435	9	6/22	237327	15
9/11	246900	18	9/29	240674	10	8/17	234194	17
8/11	245447	19	9/2	239657	11	7/29	233029	19
6/30	244151	21	9/1	231059	19	8/23	232893	20
8/10	240903	26	8/16	228476	21	7/28	230733	23
7/13	239671	29	6/29	221914	26	6/21	229851	24
9/10	238688	30				9/20	228138	29
8/18	222579	45				9/2	221900	36
Eligible days		128			126			127
15th highest day	247759			236793			237327	

have CPP days if and only if system conditions are very constrained, which is likely to make the program seem more sensible to customers.

I empirically investigate the difficulty of a CPP design with a fixed number of CPP calls per season or year in two ways. First, it would be useful to get some idea of how restrictive the limited number of calls really is. PG&E has run a small residential CPP program since 2009, which is called "SmartDays." I compare the actual SmartDays called in that program to the day-ahead system load forecasts during CPP hours from the California Independent System Operator (CAISO). Using day-ahead load forecast rather than actual real-time load separates out the day-ahead forecast error, which is unavoidable if CPP calls are required to be made 1 day ahead. The systemwide peak-load forecast isn't a perfect indicator of system stress, but it is probably as good as any single indicator that is available on most days, particularly since CPP days in these utilities are called for all residential customers or none.

For each year in Table 4, the first column shows the days that were called as SmartDays, the second column shows the day-ahead load forecast in the CAISO during the CPP hours, and the third column shows the rank of that day among all the SmartDays eligible days that year, ranked by day-ahead load forecast.[35] The rank variable demonstrates the problem that utilities face: Over these 3 years, 42 % of the SmartDays that were called were not in the top-15 load forecast days for their years. The bottom line

[35] PG&E called only 13 SmartDays in 2010.

of the table shows the 15th highest day-ahead load forecast during SmartDay eligible days each year. The load on the 15th highest day-ahead forecast is as high as 11 % above the forecast load for some of the days that were actually called. This also demonstrates some of the cross-year variation. Though the 15th-highest load forecasts are nearly identical for 2010 and 2011, 2009 had more hot summer days; the 15th highest forecast was considerably higher, a value that would have made it the 8th highest forecast in 2010 and the 5th highest in 2011.

This is just an illustration of the problem—it doesn't account for all of the factors that indicate the stress on the system and it doesn't yields a calculation of the cost of calling the wrong days. Still, it lends support to the analytical conclusion that fixing the number of CPP calls for a year will lead to less efficient use of the CPP price flexibility.

In light of these problems with using a fixed number of CPP calls, it's worth exploring the practicality of the alternative, surrounding-hours revenue offset. The primary value of this approach is to reduce the connection between calling CPP days and maintaining the regulated profit level for the firm.

Using the load research data from PG&E and SCE, I study the magnitude of the offsetting price decreases that would be needed to balance the revenues during CPP calls under the alternative unlimited CPP approach. In particular, taking all days with a day-ahead forecast 1 pm–7 pm total system load over about 249,000 MWh—which yields an average of 15 days per year over the sample periods of each utility—I calculate how much and for how long the price would have to fall during off-peak periods around those CPP days to make the program revenue neutral, which is the same as profit neutral under the assumption of no demand response.[36]

In the equitable dynamic pricing approach that was presented earlier, the prices were set to be revenue neutral among different tariffs when *all* customers are on each tariff in order to avoid cross-subsidies. That calculation would still be done before each year or season for a cost-representative price structure, as was discussed earlier, and with the assumption that the expected number of CPP days occur. In actual implementation, however, CPP prices could be implemented with slightly higher non-CPP prices at most times, but a lower price surrounding each CPP call than shown in the CPP tariff in Table 1. The goal of these lower prices in the hours that surround the CPP call would be to offset the revenue gain from a CPP call on average *given the set of customers who have opted in to the CPP tariff*. By doing so, this would neutralize the utility's incentive to call CPP days, which creates an incentive-compatible policy in which the utility is permitted to call CPP days whenever they are appropriate, rather than to raise revenue.

To analyze this possibility, I look only at customers who are "structural winners" under the CPP tariff. I study all such customers, which would be equivalent to any random selection among these customers. So, the analysis assumes that a random selection of customers among the structural winners, and none of the structural losers, sign up for the CPP tariff.

[36] To be exact, I use as CPP days only those with CAISO day-ahead forecast 1pm–7pm total system load of at least 249,094 MWh during 2006–2009 for the PG&E analysis and 249,981 MWh during 2004–2008 for the SCE analysis.

Table 5 Rebate ratios for CPP with surrounding-hours price reduction

PG&E			*SCE*		
Surrounding hours price ($/kWh)	Same-day discount	Extended discount	Surrounding hours price ($/kWh)	Same-day discount	Extended discount
$0.01	1.09	0.77	$0.01	1.32	0.95
$0.03	1.27	0.89	$0.03	1.54	1.10
$0.05	1.52	1.07	$0.05	1.84	1.32

"Same-day discount" applies the surrounding-hours price to all hours of a CPP day except 1pm–7pm. "Extended discount" applies the surrounding-hours price from 7pm on the day before the CPP day to 1pm of the CPP day and from 7pm of the CPP day to 1pm of the following day

Table 5 shows three levels of possible surrounding-hours prices that could surround a CPP call and the two different surrounding periods to which those off-peak prices could apply: (1) *Same-day discount*, all hours of the CPP day other than the CPP period (1pm–7pm) and (2) *Extended discount*, all hours from 7pm on the day prior to the CPP day until 1pm on the day following the CPP day.[37] Each cell of Table 5 then shows, the "rebate ratio":

$$\text{Rebate Ratio} = \frac{\sum_{h \in CPP_{sh}} (P_{TOU_h} - P_{sh}) \cdot \sum_c q_{ch}}{\sum_{h \in CPP_{ph}} (P_{ph} - P_{TOU_h}) \cdot \sum_c q_{ch}} \tag{1}$$

where h indexes hours and c indexes customers, CPP_{sh} are the hours that surround the CPP calls in which P_{sh} applies (shown in the lefthand column of Table 5 for each utility) and CPP_{ph} are the peak hours in which P_{ph} (= \$0.80) applies, and P_{TOU_h} is the TOU price for that hour from Table 1. A rebate ratio less than (greater than) 1 implies that each CPP call increases (decreases) revenue.

Thus, starting from the TOU rate in Table 1, if PG&E implemented a CPP rate by raising the CPP price to $0.80 during CPP days from 1–7pm and lowering the price to $0.05/kWh at all other times of the same days—and assuming no customer price response—this would cause the PG&E revenue collection to be 52 % higher than would be collected under the TOU rate over the 60 CPP days of the 4-year sample period. Table 5 shows that lowering the price at all other hours of the same day for CPP days would result in increased revenue even if the price were lowered to $0.01/kWh. The difficulty of lowering the surrounding-hours price to offset revenue gains is even more pronounced for SCE because its customers tend to have peakier demands.

However, Table 5 also shows that using the extended discount hours it is possible to lower the rebate ratio to 1, the point at which a CPP call would be revenue-neutral to the utility. Using the extended discount hours, PG&E would have to lower the surrounding-hours price to about $0.04/kWh to make CPP calls revenue neutral, while SCE would have to lower the price to slightly below $0.02/kWh. While these are prob-

[37] For consecutive CPP days, I do not "double count" the revenue decline from a lower price during the hours between the two CPP periods.

ably somewhat below the true marginal cost for supplying power in these hours, they are likely not so low as to create substantial deadweight loss from over-consumption.

Furthermore, in practice, the surrounding-hours prices would almost certainly not have to be as low as shown in Table 5 to neutralize the revenue change. These calculations assume no customer price response. Customer price response would lower critical peak consumption and raise surrounding-hours consumption, which would lower the rebate ratio, and thus allow either reduction of the number of discounted surrounding hours or an increase in the surrounding-hours price that would still yield a revenue-neutral CPP policy. Also, the calculations in Table 5 assume that there is no selection effect among the structural winners who opt in. To the extent that customers with the most advantageous consumption profile opt in disproportionately (among structural winners), that will also lower the rebate ratio.

The number of CPP days called will also affect the rebate ratio. If the total load threshold for a CPP day is set lower, yielding more than 15 CPP days per year on average, then the incremental days would have lower peak demand on average, so extending the same off-peak pricing policy would lower the rebate ratio. Put differently, lowering the threshold for calling CPP days would mean that the size or duration of the surrounding-hours discount around each CPP period would not have to be as great in order to maintain revenue neutrality. Conversely, reducing the number of CPP days by increasing the threshold could mean that each CPP event would require a larger or longer-lasting surrounding-hours discount around each event (holding constant the level of the critical-peak price).

8 The Trouble with Peak-Time Rebates

While residential dynamic pricing has not been adopted in the US, there has been much more interest among regulators and some utilities in an alternative known as peak-time rebates (PTR). Under a PTR tariff, consumers are informed when the utility forecasts a PTR event day (due to very tight supply/demand balance or high wholesale prices), and are given a payment if they reduce consumption below some baseline level during the PTR event period. Eligibility for PTR in some cases requires the customer to be on a non-standard price schedule at all other times, which may be TOU or be set at different price levels than the standard tariff. In most cases, however, all residential customers are eligible.

A typical PTR gives the customer a rebate that is based on the difference between the baseline level and the customer's actual consumption during the PTR period. PTR periods are similar to CPP periods, generally non-holiday weekday afternoon hours when supply is expected to be very tight. If the customer's consumption during these hours is above her baseline level, then the PTR has no impact on her bill; there is no penalty. If it is below the baseline level, then the customer is paid the PTR rebate for the difference from the baseline.

The attraction of PTR is that it is seen as a less harsh approach to giving customers an incentive to conserve when the system conditions are strained. Though the marginal incentive to conserve appears at first to be similar to CPP, in practice it is likely to be quite different.

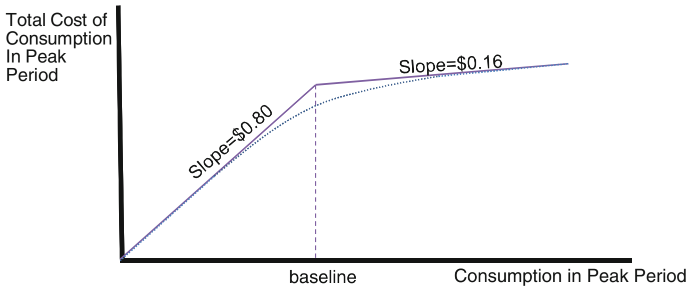

Fig. 4 Actual and perceived tariff under peak-time rebates

The solid line in Fig. 4 illustrates the effective marginal price that is faced by a customer during a PTR event, under the assumption that the flat-rate tariff is $0.15/kWh and the rebate for dropping below the baseline is $0.65/kWh. If the customer's baseline were completely exogenous and set so high that she would certainly be on the steep part of the tariff, this would closely resemble CPP.[38] Neither condition holds, however, which causes a number of implementation problems.

First, baselines are set endogenously. Typically, they are based on the same customer's usage during peak period hours on the just-preceding non-holiday weekdays, e.g., the customer's average consumption during peak period hours in the previous 3 non-holiday weekdays. This means that conserving on the days just prior to a PTR event lowers one's baseline and lowers the expected rebate. On the second day of a heat-wave, with a third day forecast, it may not make sense to conserve. More importantly, this approach to baseline setting undermines the economic incentive to make investments that lower consumption more generally, such as higher-efficiency air conditioning, insulation, shade trees, or a whole-house fan for off-peak cooling. When those improvements lower consumption on non-PTR afternoons, they reduce the expected rebate.

Second, the kinked price schedule illustrated in Fig. 4, along with the endogenous baseline setting, means that a large share of customers probably won't qualify for a rebate. They will be on the flatter part of the tariff. If the baseline is set below the expected level of consumption during the PTR event—as is generally the case when it is based on milder preceding days—then it is likely that about half or more of the customers on the tariff face almost no more incentive to conserve than if there were no PTR.

There is *almost* no more incentive because the customer is, in fact, unlikely to know her exact baseline and where her consumption during the PTR event stands in relation to the baseline. This uncertainty would alter the customer's perceived tariff schedule to be more like the dotted line in Fig. 4.[39] This uncertainty would be in addition to

[38] Even in that case, the PTR approach differs importantly in that it requires raising the retail price at all other times compared to the outcome under CPP.

[39] Borenstein (2009) shows that an optimizing customer facing such price uncertainty would respond to the expected marginal price. Ito (2012) finds that when marginal rates are difficult to observe under increasing-block pricing, customers tend to respond to an average price rather than to the marginal price.

the uncertainty that customers face under all tariffs about the amount of electricity they are consuming. With sufficient information technology—and customer attention to the information technology—these uncertainties may be overcome, but in actual implementations they are likely to make the incentives less understandable and less salient than under a CPP program.

PTR tariffs also face a problem of paying for behavior that would have occurred without the incentive. In itself, that isn't unique to PTRs; CPP rewards people who would have consumed less at peak times even without the price incentive. What's different about PTRs is that the "no lose" option that is illustrated in Fig. 4 implies that random variation in consumption will lead to net payments to customers, rather than netting out to zero. With a CPP, if a customer happens to consumer more on one CPP day and less on another due to random events, the two deviations balance out in the billing. In contrast, because of the kinked tariff schedule, if a customer happens to consume less on one PTR day for reasons that are unrelated to the tariff, she receives a payment, but that is not offset if she happens to consume more than usual on another PTR day. That is, greater variance in consumption on PTR days is rewarded per se, regardless of the net savings.

While the economics of PTR are clearly inferior to CPP, there is less resistance to PTR among residential customers, and it could potentially play a complementary role. An opt-in CPP could be paired with a default flat rate with PTR. For customers who choose not to opt in to CPP, an equitable flat rate tariff would be set as described earlier. Then the rate would be further increased slightly to pay for the revenue shortfall that would occur within this group from paying the peak-time rebates. Shadow billing could continue to inform each customer whether they would be better off on the opt-in CPP tariff or the default flat rate with PTR.

9 Conclusion

With the widespread introduction of smart meters and the continuing improvement in this technology, the benefits from dynamic retail electricity pricing are more accessible than ever before. Yet, public resistance to dynamic retail tariffs has been passionate at times, though it is unclear how broad the resistance is. Mandatory or default dynamic tariffs would be quite desirable from an economic point of view, but they seem unlikely to be adopted any time soon in the residential sector.

In this paper, I have explored some options for successful implementation of an opt-in residential dynamic pricing tariff. With smart meters installed, it is now straightforward to base both an opt-in dynamic tariff and a default flat rate on the same underlying hourly cost assumptions. Such an approach would bolster the legitimacy of the dynamic tariff and would make clear how both tariffs should be adjusted as customers with varying load patterns migrate between them. The technology also makes it possible to offer shadow bills to all customers that inform them on a monthly and annual basis how their actual bill compares to what they would have paid under alternative tariffs. These approaches seem likely to increase substantially the attractiveness of dynamic pricing to the majority of residential customers who would pay less overall under such a tariff.

Total payment is not the only criterion for customer acceptance, however. Bill volatility is also a serious concern. I have suggested what I believe is a new approach to helping customers deal with bill volatility while at the same time maintaining greater salience of electric bills than results from the level payment plans that many utilities now offer. The approach, which has some parallels to credit cards and revolving credit accounts that department stores have offered, would still emphasize the liability that the customer has incurred each month.

The empirical analysis that I report here—using stratified random samples of customers in the service territories of Pacific Gas & Electric and Southern California Edison—suggests that even without any demand response to peak prices, mandatory dynamic pricing would have a fairly modest impact on the bills of most customers. Demand response would improve the result. Low-income customers appear to have load profiles that are no flatter or more peaky on average than other customers. Smaller-use customers, however, are more likely to have lower-cost (flatter) load profiles. If customers can respond to peak prices—and there is now broad research support for the conclusion that all types of consumers can—that would make the dynamic tariff a winner for a substantially larger set of customers.

The empirical analysis also suggests that the opt-in dynamic pricing approach that I describe here would have a quite modest impact on the bills of the customers who choose to stay on the flat rate. Even a scenario with no demand response implies a likely increase in the flat rate of just a few percent or less given the likely enrollment rates.

Implementation of dynamic pricing has focused primarily on forms of critical-peak pricing. I've shown that the common structure of CPP programs puts utilities in an impossible demand forecasting position that seems virtually certain to leave them calling event days when there is little supply/demand justification or being unable to call events when there is. An alternative approach could remove the prescribed number of calls and still result in a revenue-neutral program.

Finally, I contrast dynamic pricing with peak-time rebate programs that have garnered support from some regulators. PTR appears at first to roughly mimic CPP, but in fact it does less to incent conservation in the short run and can undermine longer run incentives to invest in energy efficiency. Marginal prices are also more obscured under PTR and therefore less likely to be effective. Still, a default PTR may be a useful complement to an opt-in CPP for those who do not choose CPP.

My focus in this paper has been on the distributional and customer resistance issues that have slowed the rollout of dynamic pricing, not on the benefits that it can deliver. Those benefits are significant, as has been shown in numerous studies. With the adoption of new metering technologies, the value of addressing the remaining concerns about dynamic tariffs is even greater than before.

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