Consumer-Friendly and Environmentally-Sound Electricity Rates for the Twenty-First Century

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Abstract: This paper emphasizes the importance of bringing off-peak rates down to their marginal costs so that the current mispricing of electricity does not act as a substantial deterrent to the reduction of greenhouse gases, as through vehicle electrification. It considers whether there are feasible, efficient and equitable time-varying electricity rate structures that will be attractive to large numbers of residential customers with smart meters. One family of rate structures called Household On and Off Peak (HOOP) plans meets the efficiency criterion and is promising for meeting the distributional ones. HOOP plans utilize marginal-cost time-based rates except for fixed infrastructure charges that vary by customer group and cover nonmarginal expenses. Two alternative equity principles to guide the assignment of the fixed infrastructure charges to different groups are considered. A representative sample of California residences with usage data for each 15 minute interval for a one year period enables some preliminary tests of these HOOP designs. Simple statewide versions of these designs replicate reasonably closely the actual bill distribution that results from the independent and far more complex rate structures in use by the three separate utilities that service these residences, suggesting that each utility could use HOOP designs to meet the necessary criteria.

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I. Introduction

Electricity rates faced by residences in the United States and many other countries are fundamentally misconceived. Left as is, they would cause dire consequences as we face the environmental challenges caused by greenhouse gas emissions during the course of this century. The source of the problem is the "average cost pricing" that seemed to serve us relatively well during most of the 20^{th} century, apart from the environmental concerns that we only became aware of retrospectively. According to a recent FERC survey, 99 percent of U.S. residences continue to pay a rate per kilowatt-hour (kWh) that does not vary at all within a day. I will refer to this as "time invariant" pricing, even though these rates generally are regularly adjusted for seasonal factors and changing fuel costs. However, the cost of providing electricity varies from as low as 1-cent per kWh to over $1 per kWh depending upon the time and day that it is provided. Those on time invariant rates pay the average and have no incentive to economize when marginal costs are near their highs, and no incentive to take special advantage when marginal costs are near their lows.

Economists have lamented for years about this distortion between actual marginal costs and actual rates. However, the emphasis of these laments has always been on overconsumption during the peak periods. This article, however, while accepting these prior laments, wishes to emphasize the other problem: underconsumption in the off-peak period caused by actual rates far above marginal costs. Serious environmental harm is caused by overcharging residences for their off-peak consumption. Increased use of off-peak resources, especially as they become greener over time (e.g. in many parts of the country, there is plentiful wind during the night), can be a key mechanism for reducing greenhouse gas (GHG) emissions. I will explain this shortly, but there is more. Given the ways in which electricity providers have experimented with time-varying residential rates, it is not surprising that a number of consumer groups have strongly resisted efforts to spread utilization of them. The concerns are typically that many residential customers will be made worse off by time-varying rates, and that this group will disproportionately include customers that are least-able to protect themselves from harm: the elderly in retirement homes who need winter heat and summer air-conditioning during peak periods, those whose consumption is metered by a landlord who responds to higher bills simply by higher rents, and the poorly informed who may not understand why their bills are higher and what they can do about it.

These latter concerns are very real and must be addressed. However, we cannot lose sight either that collectively we will be much better off by fixing the problem rather than continuing in our last-century ways. Smart meters and smart appliances that make it easy for customers to respond must be accompanied by time-varying prices that give appropriate signals. Therefore, the bulk of this article is about how to have our cake and eat it too. I propose a system of time-varying rates called the Household On and Off Peak pricing plan or HOOP pricing for short. The green and efficiency emphasis of the plan is to provide marginal-cost based rates per kWh that are the same for all residences within a distribution system. The consumer-friendly and distributional emphasis is to change the way infrastructure costs are collected, away from the simple but inappropriate time-invariant volumetric charges that are nearly universal now. I explain a different way that, in combination with the green marginal-cost based per kWh charges, will leave almost all residences with bills close to their current bills at equivalent consumption. Almost everyone will find it sensible to change their consumption somewhat under HOOP pricing, and because of this almost everyone will end up better off than under the old time-invariant plan.

I would also like to clarify at the outset that HOOP plans are actually a family of plans, and that the degree of time variation in any specific HOOP plan can be lesser or greater. The simplest HOOP plan designates one period like 2-7PM each workday as the peak period with a constant rate equal to the marginal cost of providing electricity within it, and all other times as off-peak periods with a constant and lower rate equal to the off-peak marginal cost. HOOP plans can divide a workday into more than two periods (e.g. peak, mid-peak and off-peak), and they can add more dynamic features to the pricing. A HOOP plan can have as a feature that a limited number of days of the year during which demand threatens to outpace supply can be declared as "critical" days (usually with 24-hour notice) in which the peak period price is substantially higher than the usual peak price. A HOOP plan can be fully dynamic and use rates that equal marginal costs within very short time intervals (e.g. 15 minutes), such that the rates vary both within a day as well as day by day. Each of these plans uses marginal-cost based rates, and to be within the HOOP family they must also use HOOP methods for collecting any additional revenue above the marginal-cost based revenue necessary to keep the electricity distributor whole. While I think that we must phase out time-invariant rates (Friedman 2011), I also believe there can be considerable individual customer choice from within a menu of plans like those within the HOOP family.

Before considering the details of HOOP pricing, I will first explain the sense in which we need to encourage increased off-peak electricity consumption. This has little to do with juggling the time of electricity consumption that will occur anyway, as when one chooses to delay running a dishwasher until the off-peak period. That juggling can be quite valuable as one shifts from a high-cost time to a lower-cost one, and at certain times it can be extraordinarily valuable (see Borenstein 2005). Furthermore, such valuable shifting will only be made easier and more attractive as the grid smartens, and it becomes a simple matter to instruct refrigerators, air-conditioners, and water heaters not to work so hard during peak periods, and to make up as necessary once that peak has passed.

But I have in mind essentially new electricity consumption. Specifically, I am thinking of the incentives that people have to switch from using petroleum-fueled vehicles to those that can be electrically-fueled. This kind of switch offers enormous potential for reducing greenhouse gases, as the emissions resulting from petroleum-fueled driving far exceed the emissions from electrically-fueled driving even with our existing generating sources (see Friedman 2010, 2011). This potential vastly increases as the generating sources themselves become cleaner. But right now, we are inefficiently discouraging this fuel substitution (and not encouraging cleaner generation) by charging many multiples above marginal costs for off-peak electricity—commonly 4 times higher around the U.S., and for many consumers over 10 times higher. If people are to face appropriate incentives for making this decision, then we must get electricity rates to be set at their marginal cost levels.

How? In the next section, I explain why the time-varying rates used in pilot projects and in proposals are often ones that would cause a substantial portion of the residential customer class to be losers, and thus not surprisingly have created pockets of resistance to time-varying rates among consumer groups. In the third section, I explain the logic underlying HOOP rates. In the fourth section, I illustrate empirically how one would design HOOP rates to apply to a representative cross-section of California residences, and in a fifth section I examine the strengths and weaknesses of this design. The concluding section summarizes the results of the analysis and the policy implications.

II. Prior Experience with Time-Varying Residential Electricity Rates

As mentioned in the introduction, a recent FERC survey (2010) reports that only 1% of U.S. residences are on time-varying electricity rates. In a state-by-state look at these in Friedman (2011), there is only one state with more than 3% of residential customers on time-varying rates, and that is Arizona in which FERC reports 28% of residential customers are on such rates. Why are these plans so wildly unpopular?

An early review by Aigner (1985) of U.S. residential electricity pricing with time-varying rates reports on 15 projects co-sponsored by the Department of Energy (DOE), the first of which began in Vermont in 1975. These occurred in the period following the October 1973 embargo of oil to the U.S. by OPEC, when interest in in energy efficiency and energy security was high. In all of these efforts, the objective was to discover just how responsive residences are to the peak-period prices. In none of them was the purpose to see if large numbers of consumers would prefer the time-varying rates to their original time-invariant plan. In many of these first experiments, only volunteers were chosen so that (a) they were not representative of the population, and (b) it would hardly be surprising if they were far more disposed to like the plan as well as to respond to it than those who did not volunteer. Thus the key question of customer responsiveness was not settled by these early experiments, and the desirability of the plans from the customer viewpoint was not seriously considered. Even though some of the jurisdictions followed the experiments by making residential time-of-use plans available as an option, very few consumers chose to avail themselves of this option.

During the 1980s and 1990s, the public's interest in energy conservation *per se* waned, although there remained substantial interest in mitigating the environmental consequences of burning fossil fuels. Then in the mid-to-late 1990s, riding a different wave from the deregulation movement that began with airlines, trucking and telecommunications, interest arose in electricity restructuring to foster more competition in this industry. California was the leader of this movement in the U.S. (the United Kingdom began earlier), but its initial efforts failed and led to its electricity crisis of 2000-2001 (Blumstein et al 2002, Friedman 2009). One of the lessons from experience was the value of having greater demand responsiveness—some system other than rolling blackouts that could be triggered to reduce demand as an additional instrument for grid stability and reliability. This rekindled interest in time-varying prices, and especially because technology has progressed considerably over the years, it has become much more feasible to think of implementing more dynamic rates than the simpler peak and off-peak distinctions of the early experiments. Not only are much smarter meters practical to install, but there are a host of developing technologies to make it easy for customers to set up automatic responses to dynamic rate changes: smart appliances like dishwashers, dryers, and other appliances that can wait for low rates before they run themselves.

Some experiments and studies have been undertaken since the early ones, although there remains considerable uncertainty about just how responsive large numbers of customers would be to time-varying rates. Lijesen (2007) provides some review of price elasticity estimates, presenting a range for households of -.1 to -.6 with the lower half generally for short-run elasticities and the upper half for the long-run. Similarly Reiss and White (2005) provide a short-run estimate for California households of -.39, noting that those households with air-conditioning or electric space heaters are significantly more elastic (and other households less elastic). When one examines those studies that involve time-varying rates for households explicitly, the estimates of responsiveness are usually at the lower end of the range: there is not much evidence that there would be very large peak reductions in response to the peak-period prices that have been tested. But that does not mean that the reductions achieved would not be worthwhile, and recent studies emphasize the very high value of achieving even small reductions at peak periods (Borenstein 2005). The very recent studies by Wolak (2010, 2011) find substantial peak reductions of households in the Washington DC area to several different dynamic rate structures, and importantly for the future, he notes greater elasticity among those households equipped with smart thermostats. Along the same lines, Faruqui and Palmer (2011) report that in 24 of the most recent pilot projects involving dynamic rates, the median peak reduction was 12 percent.

As I indicated earlier, the literature on time-varying rates emphasizes peak responsiveness, and does not really consider the type of long-run off-peak responsiveness that I think can be far more substantial than what short-term, pre-electric vehicle trials have been able to observe. But of equal importance, this literature also does not deal with the great difficulty of getting residential customers on to time-varying rates. One exception is Letzler (2007), who notes that the time-varying rate design used in California's critical peak pricing experiment would increase bills for more than 55% of customers in a climate zone where high participation would be desirable.[1]

III. The Essential Logic of Household On and Off Peak (HOOP) Pricing

As mentioned, HOOP rates are a family of time-varying plans with members that vary in just how much time variation there is. The least dynamic of these plans is to have peak and off-peak periods with fixed rates for months. The most dynamic is to have real-time pricing in which the retail price can change frequently (e.g. each hour) and is generally related to the rise and fall of wholesale electricity prices. The empirical investigation used in this analysis will utilize the simple peak and off-peak version, although the same logic applies to any version and the specific version used here may not have much bearing on the distributional results. Also for simplicity and with an eye toward implementation, we will follow standard public utility commission practices and examine the distributional effects on a "test year" of household consumption data—thus not attempting to estimate any behavioral responses to the proposed designs.[2] We will also make all plans be revenue neutral: each will be designed to collect the same total revenue as the current plan, and thus the average bill must be the same as the current average bill.

Following Friedman (2011), for any given estimates of peak and off-peak marginal costs per kWh, we calculate the marginal cost revenue (*MCR*) at the old consumption levels. Because there are non-marginal costs incurred and entitled to cost recovery, *MCR* will usually be less than the revenue requirement (*RR*). HOOP plans build on the two-part tariff idea to assess an additional fixed cost per customer (*FC*) chosen to make up the revenue difference. If there are n customers and one uses a uniform fixed fee, this means:

$$FC = (RR - MCR)/n \qquad (1)$$

The important efficiency property of the fixed part of the system is that it be a charge that does not affect the consumer's behavior (an incentive for which there is no response). Virtually all residential

[1] P. 173 of Letzler (2007).

[2] Of course this does not mean that we are uninterested in behavioral responses; they are the main motivation for wanting to reform the rates! Customers will know that it has become relatively inexpensive to increase off-peak usage, and that the rewards to conserving during the peak have grown. All responses to these changed incentives imply gains from the consumer (and provider) perspective.

customers regard it as a necessity to remain connected to the electricity system (i.e. the only way to avoid the fixed charge is by going completely off the grid). While one can imagine that a very high fixed fee could lead to significant abandonments of the grid, practically the fee levels are unlikely to exceed 20-30 % of revenues. This fixed charge could also be used in restructured electricity systems that have retail competition, if implemented as a nonbypassable charge used to pay for any noncompetitive assessments (e.g. the cost of the distribution system).

The principal problem with the above method is a fairness issue: both small and large customers would pay the same fixed cost, even though they have not been charged this way in the past. Furthermore, to the extent that smaller customers tend to be the least well-off and vice versa for the largest, this is a regressive method. Consumer groups are very sensitive to any proposed rate reforms usually for this distributional reason. Households often have made residence decisions under the assumption that rate structures for necessities like electricity will remain stable, and they are angered by any proposed reforms that threaten to make them worse off.

One way of responding to these concerns, without sacrificing the desirable efficiency properties of marginal-cost based rates, is to recognize that all customers need not have the same fixed cost.[3] Suppose we think of the fixed cost as an assessment for the customer's fair share of infrastructure costs. One rational way to assess it that is very difficult to alter through customer responses would be in rough proportion to long-term, historical consumption, for example. A simple procedure to do this would be to divide residential consumers into large groups based on average annual consumption over the past few years, and then set a fixed charge for the households in each group such that the charge rises as one progresses to the higher-consuming groups. More generally for *k* groups, we set $FC_1, FC_2, \ldots, FC_k$ such that

$$FC_i = (RR - MCR - (\textstyle\sum_{j \neq i} n_j FC_j))/n_i \quad \text{for } i = 1,2,\ldots k \qquad (2)$$

where n_i is the number of customers in group *i*.

If the fixed fee rises proportionately with the group's average consumption $\bar{Q}_i$, then the following relation will hold:

$$FC_i/FC_j = \bar{Q}_i/\bar{Q}_j \qquad \text{for all } i, j \qquad (3)$$

Equations (2) and (3) can be solved for the FC_i for any group definitions given values of the other parameters (n_i, $\bar{Q}_i$, *RR*, *MCR*).

The strict proportionality rule (3) may not correspond to what in practice is considered equitable. In some jurisdictions, for example, it might be thought fairer to "protect" the lowest usage groups by discounting their fixed fees to be lower than what would be the proportionate share. This would be a more progressive fixed fee schedule, and other variants are possible. As one simple example, the lowest group could be assigned a fixed fee designed with reference to an independent standard to ensure the affordability of consumption within this level (a "baseline" group rather than a "baseline" quantity). If marginal costs are high, this fixed fee could be negative: a credit to be applied against the marginal cost charges. Then the fixed fees for all other groups could be set in proportion to one another as above to ensure all revenues sum to the revenue requirement.

[3] See Friedman and Weare (199

An alternative and possibly quite different rule from proportionality or its variants is "status quo equity" that assumes the distribution in the current system is already fair. This standard implies trying to minimize any bill changes caused by a switchover to a different rate design. This is equivalent to assigning each group its own RR_i (the total revenue group *i* contributes under the status quo) and then:

$$FC_i = RR_i/n_i - MCR(\bar{Q}_i)) \qquad \text{for all } i \qquad (4)$$

where $MCR(\bar{Q}_i)$ is the marginal cost revenue at the average consumption level in group *i*. Since *MCR(Q)* is linear in *Q*, equation (4) for all i ensures that equation (2) holds.[4] Then the bill for the average consumer within each group is identical to its historical level at historical consumption. If the groups are defined to be relatively homogeneous, no one's bill will depart very much from the historical level.

These are the fundamental ideas that underlie HOOP rate designs: marginal-cost based rates, and nonmarginal infrastructure costs assigned through fixed fees to subgroups of consumers in accordance with equity norms. Now let us turn to how they might be utilized in practice.

IV. HOOP Rates for California Residential Electricity Customers

A. The sample population

In 2003-2004, the state of California undertook a formal experiment to determine how California residents would respond to a dynamic electricity pricing concept referred to as critical peak pricing. To conduct this experiment, meters that recorded consumption in 15-minute intervals were put in place for three randomly selected groups, including a control group that received no treatment at all. Continuous observations were collected for up to 16 months. Of the treatment groups, one was placed on standard time-of-use pricing (with rates the same from day to day within any season), and the other on critical peak pricing that added a dynamic component to what would otherwise be the same standard time-of-use as the first treatment group. This dynamic component was that for up to as many as 15 days per year, a utility could declare with 24-hour notice that the next day would be "critical" and a substantially higher than usual peak-period rate would apply during the peak hours of this critical day.

Our interest is in the control group, a stratified sample that was designed to be representative of the state's residential electricity customers as a whole. Very little is actually known about the time pattern of residential electricity consumption, and this data may provide one of the first good pictures that apply to large residential populations.[5] After presenting this picture, we use this control group to analyze how the bills of California residences would be affected by a switch from the time-invariant rates that virtually all residences are on now to a few variants of a simple HOOP plan.

While the control group is representative of a very large portion of California residences, there are a few qualifications to this that should be noted. One is that the sample population consisted only of the residences that are served by the state's three large investor-owned utilities (IOUs); excluded are approximately 22 percent of the state's residences that are served by other distributors (e.g. those served by the Sacramento Municipal Utility District or by the Los Angeles Department of Water and

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[4] See Friedman (2011) for details.

[5] Existing reports of residential time patterns generally come from small-scale experiments often with volunteer populations, like those mentioned earlier, that may not be representative of their jurisdictions or larger residential populations.

Power).[6] Within the IOU population, excluded were the small number of households that were already on time-of-use plans or special plans that allowed the utility to cycle the air conditioners and reduce consumption during hot days (and thus excluding some of the most time-sensitive customers). The sample also excluded households that were eligible for medical discounts because of special medical needs (presumably a group of time-insensitive customers), although we found a small number of participant households that apparently became eligible for these rates for some months during the course of the experimental period. The sample excluded residences with master meters rather than individual ones, although individually-metered apartments were included.[7] So the sample is essentially representative of California IOU residential customers with their own meters on standard time-invariant rates, with slightly fewer medical issues affecting consumption than would be expected in the actual population.[8]

Our main effort is to show the distributional consequences of different ways of setting grouped assessment fees. The policy importance of this is to illustrate the feasibility of charging all customers the same marginal-cost based time-varying rates per kWh, which vastly improves efficiency and at the same time makes it possible for almost all consumers to be better off than they were under the old system. The empirical importance is that because the sample population is very close to representative of California residences as a whole, somewhat similar results might be expected to apply to other large residential populations of electricity consumers.

Previous researchers (CRAI 2004, Herter 2007, 2010, Letzler 2007) have made use of the experimental data primarily to determine the effects of summertime critical peak pricing over and above standard time-of-use, and have not focused on annual usage issues. Letzler [2007] did include analysis of the distributional question of how critical peak pricing affected summer residential bills, and showed that design variants of critical peak pricing could both retain its important efficiency features and be done in a way that would make virtually all customers better off. With Letzler's finding in mind, we therefore focus on the more basic question of how time-varying plans in general are likely to cause distributional concerns as residences switch from standard time-invariant plans.

The original sample design as described in CRA [2004] called for 470 control residences, of whom 20% were expected to opt out and not participate. CRA reports 375 controls with the necessary meters activated, almost exactly 80%. A small number of those agreeing to participate did not do so for very long for various reasons like moving. We found 331 control households with over 80% of the 15-minute interval data from July 2003-June 2004. These 331 households and their 3972 months of consumption data comprise the sample of this study.

Because the data from the experiment has not been used for analyzing annual usage patterns before, we found that some data cleaning and enhancement improved its quality for our purpose. Other researchers like Letzler [2007] had noticed previously some small data anomalies like a few miscodings of holidays as having peak consumption (all holiday consumption is off-peak), and we accepted these corrections. We also noticed a few billing anomalies, like a few months of bills from a small number of

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[6] According to EIA data in File861 for 2009, California has 12,925,840 residential electricity customers (meters) of whom 10,056,592 are served by the three large IOUs: 4,254,956 by SCE, 4,578,150 by PG&E, and 1,223,486 by SDG&E.
[7] For the full list of exclusions, see p. 27 of CRA [2004].
[8] The excluded group with medical issues at the start of the experimental period presumably had more longer-term health issues than those who only developed medical issues after the start of the experiment.

households that were for amounts below the standard tariff rates but equal to the rates with medical discounts applied. Another anomaly was a small number of bills in the fall of 2003 (mostly October) within one utility's area that were much lower than the tariff rates for that month; we believe these were caused by a rebate unrelated to consumption during the experimental period and adjusted the billed amounts to be consistent with the tariff rates.[9] Billing information for SDG&E customers was not included in the dataset, so we created the bills based on observed usage and its tariffs that applied during the experimental period.

In order to standardize the dataset as much as possible, we took advantage of the detailed knowledge of consumption to create calendar-month bills so that each household had a bill for the exact same period. We did this by regressing separately the actual PG&E and SCE monthly bills (which included the meter read dates that varied across and within households) against the tiered consumption quantities, controlling for (a) climate zones that determined tier sizes, (b) lower-income households receiving lower rates (as well as the medical discount months mentioned previously), (c) any rate changes during the period, (d) daily meter costs and (e) minimum bill constraints. These regressions had adjusted R^2 near 1 (.999 PG&E, .990 SCE) and produced coefficients very close to the appropriate tariff rates for each of the households. An advantage of this method is that it allows a check to make sure that we are understanding the tariffs correctly. We learned, for example, that PG&E's published tariff rates did not reflect a 10% discount mandated by state legislation although the discount was used in calculating its customers' bills. Also, the results can easily be checked for any observations that do not appear to fit them; for example, this is how we identified the small set of observations in which the pattern of misfit was explained perfectly by temporary medical discounts applying to several contiguous months and which we would have missed simply by assigning standard tariff rates. The final regression coefficients that represent the effective tariff applying to each household for a particular month are then used to generate bills based on actual consumption for each exact calendar month, so both our detailed consumption and billing data apply precisely to a one-year period (July 1, 2003-June 30, 2004).

As mentioned earlier, the sample itself is stratified. It was designed using Dalenius-Hodges and Neyman processes to optimize the overall reliability, and oversampled high-consuming households (which had relatively high variance) and undersampled low-consuming ones (with relatively low variance). In the unweighted sample, the average monthly consumption is 694.08 kWhs and the average bill is $95.39. However, when these are weighted to give correct population estimates, the average monthly consumption for the California IOU residential consumer is 543.29 kWhs and the average monthly bill is

[9] We identified 108 such monthly bills within the SCE service area, all in the period from August 22 -October 21, 2003. A typical example is for a household that for 11 of 12 months has an actual bill in the $20-25 range and for which our predicted bill is never off by more than $.10. However for October 2003, with a usage similar to all of the other months, we predict a bill of $21.91 but the actual bill is only $7.90. It is this same pattern that we observe in the other 107 bills that we think are "rebate contaminated." For these households, we tried to predict each household's "rebate" amount (the difference between the actual bill and our prediction assuming no rebate) with an auxiliary regression that included a constant term and the bills from the previous three months. However, the auxiliary regression had almost no explanatory power. We did find in the minutes of the Hanford City Council for October 7, 2003 a report that the regional manager of SCE had good news for its residents: SCE had made a financial recovery [presumably from the 2001-02 electricity crisis] and is "offering a one time rebate to all their customers with the average rebate being $40.00 per residence." We therefore decided to treat these observations as rebate-contaminated, refined our regressions for bill predictions by excluding these observations, and then predicted bills for the calendar months based purely on the observed consumption amounts (i.e. excluding any actual rebate that is likely not based on consumption during the experimental period).

$71.72 (and thus average cost per kWh of $.132). We use the total revenue from the weighted sample of $284,862 as the aggregate amount to be collected from the TOU plans that we later consider.

As a quick check on the representativeness of the sample, we make use of a totally different data source. The federal Energy Information Administration (EIA) tracks information about the average residential price per kWh. At the January 2004 midpoint of our sample period, EIA reports the average California residential price was $.126/kWh. Recall that our sample is of the three large IOUs and excludes all the municipal distribution companies. Using more detailed EIA data available for 2009 (the F861 datafile), we calculate that the IOUs have an average cost per kWh that is 1.045 times greater than the other California electricity distributors. Assuming this same ratio applies during the 2003-04 period, then our “EIA estimate” of the average cost per kWh for the IOUs is $.132. This is identical to the sample estimate of $.132. Similarly, the EIA data are that the average residential monthly bill in California during 2003-04 was $69.32, and in its detailed 2009 data the average IOU bills were 1.028 times greater than this. Thus our EIA estimate for the average monthly IOU bill per residence is $71.28—less than 1% different than our sample estimate of $71.72. In short, we have good reason to believe that our sample is representative of IOU residential electricity consumers in California.

In the weighted sample over the full year, 95.20 kWh of consumption per household per month occurred during the 2-7PM nonholiday weekday hours that the experiment classified as peak, or 17.5% of the 543.29 kWh total mean monthly consumption. The balance of 448.09 kWh (82.5 %) occurred during offpeak hours. It is interesting that residential consumption is only slightly peak-intensive. That is, 14.5% of hours during the sample year are in the peak period, and the proportion of consumption in this period is only slightly higher.[10] Of course this division depends on the definition of peak hours, and the results might differ with a different definition. To give a better picture of the hourly pattern of consumption, Table 1 shows the kWh by hour for the full year and separately for six “summer” months (May-October) and six “winter” months (November-April), each broken into nonholiday weekdays and weekend/holidays. Table 2 contains similar information for the “hot” month of July, the “cold” month of December, and the “moderate” month of April. Figure 1 illustrates the difference in patterns between the weekday nonholidays and the weekend/holiday days. Almost all hours contain 3-6% of daily consumption, with peak residential usage in the evenings from 5-10PM. Not surprisingly, weekend/holiday consumption during the 9AM-5PM day is distinctly above the same hours during nonholiday weekdays.

[10] 111 of 366 days in the sample year were weekends and holidays without any peak hours. Of the remaining 255 days, 5/24 of the hours are peak and 19/24 are offpeak. Thus in total peak hours are 14.5% of all hours.

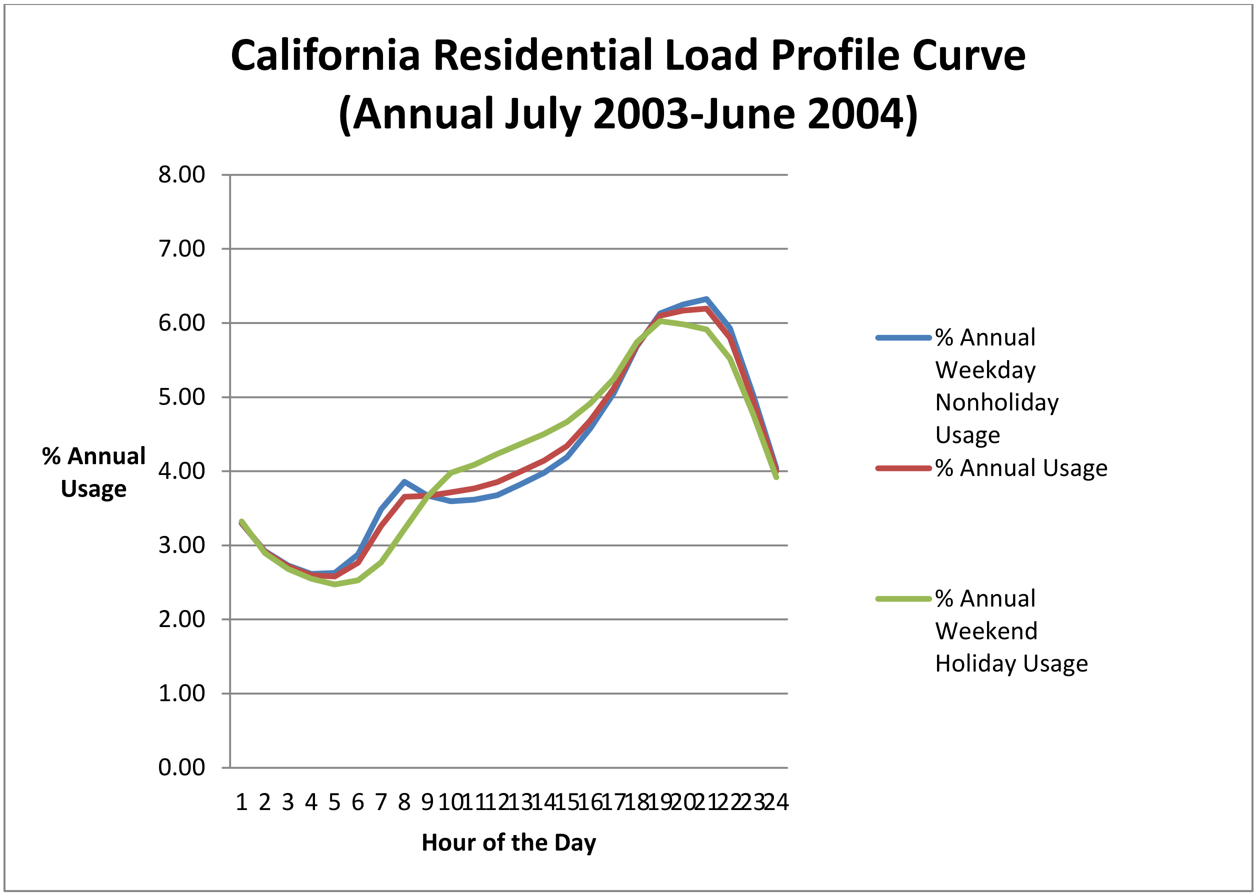

Figure 1: Residential Load Patterns for Weekdays and Weekends

Figure 2 is intended to make the point that it is not the peak or trough of residential usage that matters. It is systemwide usage (including nonresidential) that is a main determinant of the marginal cost. Residential usage that occurs during the systemwide peak is the relatively expensive usage, and correspondingly residential usage that occurs during the systemwide trough is relatively inexpensive. Figure 2 compares July load profiles of residential usage (2003) with systemwide usage (2009).[11] Note that while residential usage peaks in the evening hours (6-8PM), systemwide usage is already declining by then. The systemwide peak is between 3-5PM, and the hours from 2-6PM are the ones where usage as a percent of the daily load exceeds 5%. Similarly, all hours between 11PM and 8AM are ones in which system usage as a percent of daily load is under 3%.

[11] The systemwide data were downloaded from the OASIS system of the California Independent System Operator (CAISO). It did not have July 2003 data available. A comparable July was found by checking the website of the National Oceanic and Atmospheric Administration. It has historic information on the number of cooling degree days in July in California, which was a relatively high 300 in July 2003. July 2009 with 270 was the closest to this. The CAISO OASIS system had load data from July 1-15, 2009, which we averaged for presentation here.

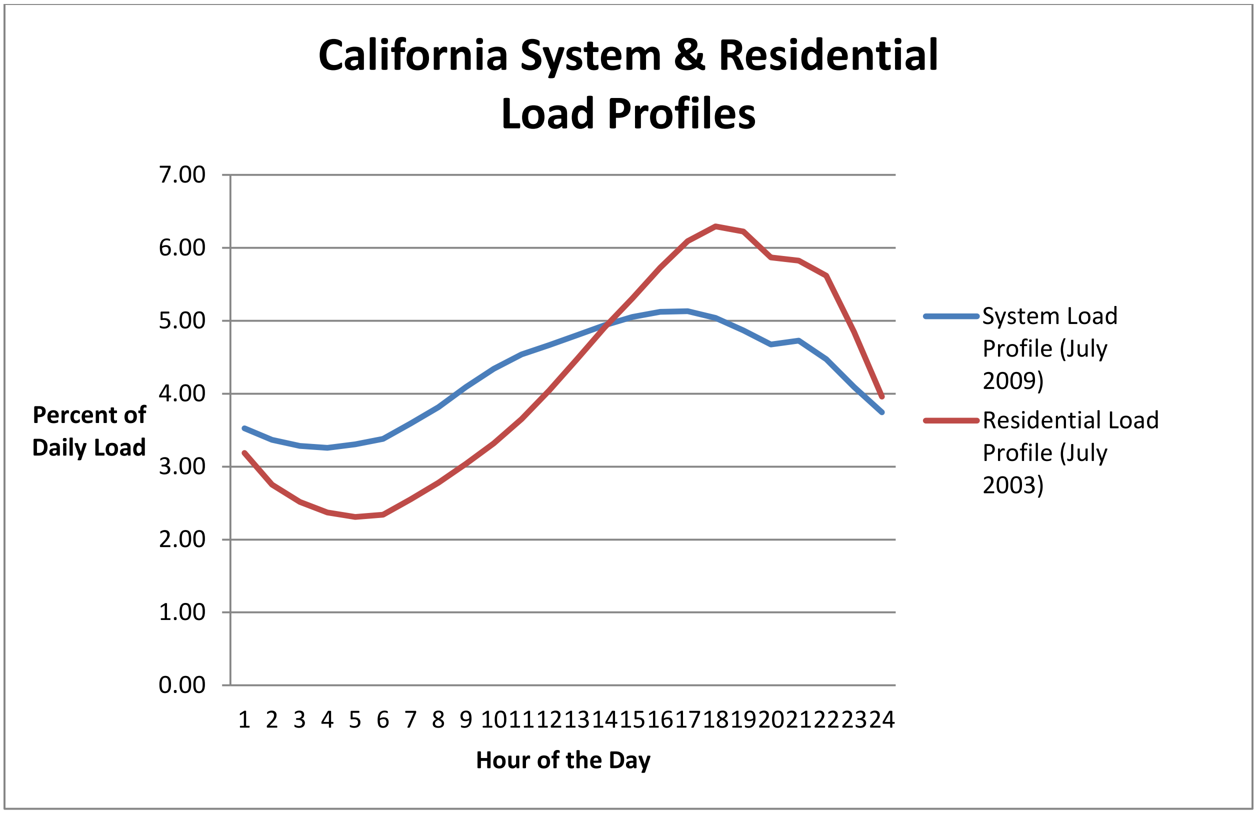

Figure 2: The System Load is Declining before the Residential Load has Reached its Peak

The final information that we wish to present about the sample population is the distribution of bills within it. From this point, all data about the distribution will refer to the weighted estimates that are representative of the statewide population. The mean monthly bill of $71.72 conceals considerable variation by household and by month. Table 2 shows the entire population ordered from the lowest to highest bills by decile categories (and finer within the highest decile), and presents the average monthly bill and standard deviation within each category. The annual column shows the distribution of monthly bills over the entire year, while the next two columns show the distributions for the "hot" month of July and for the "cold" month of December. One can see that California as a whole is a summer-peaking state, with substantially higher average bills in July than in December. But within any month, the consuming population is very diverse. For the lowest 70th percent of the population, the variation by decile is somewhat similar and the average bills increase by roughly $10 per month per decile. However, above the 70th percentile the distribution widens considerably: there is roughly a $20 per month increase from the 70th to 80th percentile, and then a roughly $30 increase from the 80th to 90th (and almost a $70 increase in July) and still greater widening from the 90th to 100th percentiles.

A challenge for any politically feasible time-of-use-plan, particularly one that might become mandatory or the "default" choice for these consumers, is to minimize any "bill shock" caused by the change from the time-invariant plan to the TOU plan. Bill shock is a large increase in the billed amount from what it would have been under the time-invariant plan. The final column of Table 2 shows the distribution of annual charges, which shows somewhat more bill clustering in the middle percentiles compared to the monthly charges. For example, the ratio of the average charge in the 80-90 percentile to the 20-30 percentile is 3.82 for the monthly means but only 3.44 for the annual means. This is also reflected in the coefficient of variation (the ratio of the standard deviation relative to the mean, calculated from the bottom row of Table 2), in which the monthly ratio is .91 but the annual ratio is only .79. At least to some extent, this is due to the statewide sample and climate variation that combines both northern, winter-peaking Californians with southern, summer-peaking Californians (a feature that would not characterize the service areas of most distribution companies). Most of the analysis to come will focus on the annual bill distributions, as being of greatest relevance to actual households.[12]

Table 2
Distribution of Monthly Residential Electricity Bills ($), California (July 1, 2003-June 30, 2004)

Percentile	Annual Monthly Mean (S.D.)	July Mean (S.D.)	December Mean (S.D.)	Annual Mean (S.D.)
0-10	13.34 (5.77)	11.43 (4.46)	13.33 (6.39)	192.04 (67.91)
10-20	23.54 (2.12)	22.34 (3.13)	25.83 (2.68)	314.96 (23.32)
20-30	31.78 (2.40)	34.07 (3.35)	36.21 (3.90)	414.04 (32.44)
30-40	40.11 (2.01)	42.64 (2.45)	45.66 (2.62)	508.65 (24.56)
40-50	47.46 (2.22)	49.79 (1.76)	57.91 (3.93)	593.02 (23.94)
50-60	56.19 (3.13)	60.20 (4.56)	68.48 (2.36)	733.17 (59.43)
60-70	69.02 (4.43)	84.17 (8.60)	80.19 (4.31)	864.53 (51.36)
70-80	88.94 (7.40)	119.36 (14.44)	99.83 (8.47)	1139.68 (87.29)
80-90	121.34 (12.41)	187.07 (26.39)	128.49 (9.42)	1426.21 (117.79)
90-95	167.06 (14.24)	279.37 (27.42)	168.01 (14.10)	1896.96 (171.26)
95-99	246.50 (36.03)	385.58 (39.57)	254.03 (35.63)	2665.13 (247.19)
99-100	431.07 (114.65)	599.37 (222.95)	370.29 (89.18)	4005.53 (1137.90)
Mean	71.71 (65.18)	97.28 (107.85)	78.38 (63.26)	860.61 (678.30)

[12] It is an open question whether or not, from a consumer's perspective, a difference in one month would matter if the annual difference is small. It is not unusual for distribution companies to offer balanced payment plans that allow payments to be predictable even though the actual new charges each month follow the annual climate cycle. Other behavioral issues also can affect the desirability of any rate design. For example, consumers on tiered time-invariant rates may be largely unaware of the marginal prices they face, reacting to the total bill instead (see Friedman 2002). These behavioral issues are somewhat separate from political expression of interests during rate proceedings—politically active interest groups that represent many consumers, like Toward Utility Rate Normalization (TURN) in California, generally understand rate plan details like marginal rates.

There is a further important issue about the bill variation that affects any efforts at rate reform in which one of the criteria is equity, as in the concern already expressed to minimize "bill shock." This issue is the complexity of existing tariff schedules, such that customers with the same usage at the same times can face very different marginal prices and can receive very different bills. Our statewide sample more than doubles this complexity, in that customers can be served by any of three different utilities, each with its own complex tariff schedule.

Table 3 shows that, even within one utility, an extremely wide range of prices per kWh and billed amounts is possible for the same usage level. The table is calculated using an illustrative usage level of 700 kWh per summer month. Prices for this quantity range from $.09 per kWh to $.21, more than double. Bills for this quantity can range from $58.21 to $107.43. The main reasons for this, under the California system, are the five tiers with price rising on successive tiers and the highly variable baseline quantity used to determine when each customer switches from one tier to the next. Tier breaks occur at fixed percentages of the baseline quantity—at 100%, 130%, 200%, and 300%. However, the baseline quantity is different in each of 10 climate zones, and within any climate zone it differs depending on the season of consumption and on whether the residence has electric heating ("all electric") or not. For a 30-day summer month, these baseline quantities can vary from a low of 219 to a high of 714, with 20 different possible bills for the same usage. Additional variation is caused by income differences: qualifying low-income residences receive CARE rates. CARE stands for California Alternative Rates for Energy and provides a 20% discount on the baseline and Tier 2 rate, and the rate does not increase above its Tier 2 level for higher usage amounts.[13] Thus within one utility there are 6 different marginal prices and 40 possible bills for the exact same usage quantity (a CARE version of each of the previous 20). Table 3 does not include still another source of variation, medical discounts. Those residences qualifying for medical discounts receive baseline amounts that are approximately 500 kWh above the non-medical baseline that would otherwise apply, and more in some cases.[14] The highest price charged to a medical discount residence is the second-tier rate, even if consumption exceeds the second tier.

The only reason for having such a complicated system is equity or fairness as determined through state legislation and CPUC rate proceedings. These price and bill variations are in no way meant to reflect any cost difference in delivering the electricity. In fact, to the extent that equivalent service (electricity provision at a given time) is being priced differently to different customers, this creates inefficiency above that caused by simple average cost pricing because it violates the economic "law of one price." The underlying equity rationale is that a residence located in a relatively hot climate deserves a larger baseline than a residence in a more moderate zone (so that effectively, those locating in moderate zones subsidize those who locate in a hotter zone), and similarly that CARE and medical discount residences "deserve" lower rates. Baseline quantities are set at 50-60% of average consumption in each climate zone. Thus it is a huge challenge to propose a reform that respects the equity objectives of the current system but removes or greatly reduces the inefficient violations of the economic "law of one price."

[13] The income cutoffs for CARE qualification depend on household size. Currently they are $31,800 for a one-person household, and $45,100 for a 4-person household. Enrollment requires the bill payer to complete a simple one-page form and self-certify by signature that the requirements are met.

[14] These discounts apply to those who certify in writing that one (or more) of the residents is dependent on a life-support device (e.g. motorized wheelchair) or is being treated for a life-threatening illness or has a compromised immune system or any of several other conditions. See, for example, Electric Rule No. 19 on the PG&E website at http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_19.pdf.

Table 3: No Law of One Price in Existing California Electric Rates

Monthly Usage (kWh)	Baseline Quantity	Classification	Bill	Marginal Price per kWh
700	714	CARE, All-electric, Bakersfield	$58.21	$.092
700	561	CARE, Basic, Bakersfield	$59.95	$.106
700	312	CARE, All-electric, Santa Cruz	$63.05	$.106
700	219	CARE, Basic, northeast CA	$64.21	$.106
700	714	All-electric, Bakersfield	$79.31	$.126
700	561	Basic, Bakersfield	$81.48	$.143
700	312	All-electric, Santa Cruz	$96.94	$.210
700	219	Basic, northeast CA	$107.43	$.210

It may seem an impossible task to offer a reform based on marginal-cost rates that apply to all without inevitably causing substantial bill shock. However, Figure 3 suggests that it may not be hopeless. Figure 3 shows a scatterplot of annual usage levels against annual bills for the representative statewide non-CARE sample, and a simple regression line for that data. Somewhat remarkably, the full range of actual variation in annual bills among the 277 non-CARE residences is 98% explained by the simplest-possible two-part tariff in which there is a monthly fixed fee of $15.40 ($184.76 annually) and one statewide price for electricity of $.165 per kWh! The regression equation (with standard errors in parentheses) is:

$$\text{Annual Bill} = \underset{(33.26)}{-184.7551} + \underset{(.005)}{.1654821}\text{*Annual Usage} \qquad R^2 = .98$$

What we will be considering are rate designs that mathematically can be thought of as lines like the above one with several key differences: (a) marginal costs would be the coefficients on usage levels, rather than being determined by a statistical program designed to find whatever coefficient brings the line as close as possible to existing bills; (b) there will be more than a single usage variable, as the time-varying charges will include at least peak and off-peak usages if not finer distinctions; (c) a constant term that is the fixed annual infrastructure charge will be assigned by equity principle to each group designated as part of the rate design. The designation of groups can be done in any number of ways, although the definitions should not be expected to change very frequently, similar to the definitions used in determining baseline quantities.

Perhaps the most natural variable to use in defining groups is usage level. Looking at Figure 3, one observes that there are substantial numbers of customers with usage levels from 0-20,000 kWh, and then a much smaller number spread out from 20,000 to over 40,000 kWh. But then again there is no reason why a utilities commission could not also require use of the same variables it now uses in setting baseline rates: climate zone and type of electric service. If these definitions were used, then the crucial change would be getting rid of the price difference by tier and replacing it instead with a difference in

the fixed infrastructure charge. The law of one price (per time period) at marginal cost would prevail, and the tier breaks would represent changes in the amount of the fixed infrastructure assessment.
At this point, let us turn to HOOP plans that can be applied to our sample and analyzed for their differences from the status quo as well as each other. One important limitation to keep in mind is due to sample size. While each utility has thousands of residences within each of its climate zones, we only have a small number from each of these zones in our sample. So the utility could easily tailor its HOOP plans for each climate zone, whereas we are restricted to using one statewide plan. Whatever bill differences we observe between our plans and the actual bills, the utilities can tailor the HOOP plans to result in much smaller bill differences.

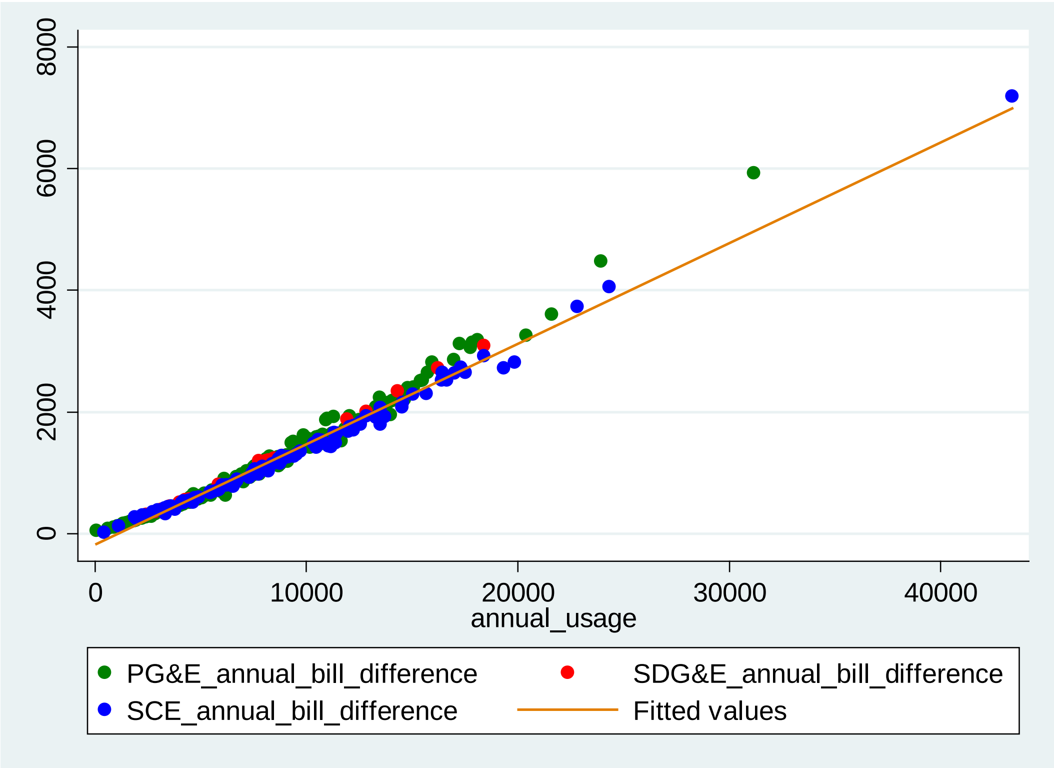

Figure 3: Despite Complex Rate Variations across Customers , Annual Usage Predicts Annual Bills

B. Toward Consumer Friendly, Time-Varying, Marginal Cost Electricity Pricing

We proceed by first specifying off-peak and peak periods and their associated marginal costs. This specification, holding individual consumption constant, will imply the marginal cost revenue that will in almost all cases be less than the revenue requirement. The difference between the two numbers is the amount that must be raised by the fixed fees assigned to each customer. In most normal situations these fees will be positive, but one can imagine unusual situations in which they are negative or a credit amount, e.g. an oil embargo like that the U.S. experienced in 1973 could make the marginal cost of generation high (because of the increase in fuel costs necessary to run many generators) and cause retail marginal cost revenues to exceed the revenue requirement. It is also possible, depending upon group definitions and equity norms, that one or more groups could be assigned a negative fixed fee, or a credit rather than a charge. This might be natural, for example, as an alternative to the current CARE or medical discount system. We will present here the normal situation in which overall marginal cost revenues are below the revenue requirement, and we will then turn to the specification of the fixed fees.

In terms of identifying marginal costs within a time period, some aspects of this are relatively straightforward and other aspects less so. One of the straightforward aspects is that marginal energy costs in the wholesale spot market during the relevant period are a large part of that period's marginal cost. Another reasonably straightforward aspect is that almost all of the costs of the distribution system are fixed rather than marginal, with the most important exception being line losses (slightly more kWh than needed by the end user must be entered into the distribution system). The least straightforward aspect is the extent to which capacity costs of the system (both generation and transmission) should enter as marginal costs.

Under the standard theory of marginal cost pricing for electricity as explained in Wenders (1976), unconstrained competitive spot market prices for electricity contain all the appropriate incentives for investment in generation and transmission resources. Unconstrained spot market prices will, during times that stress existing system capacity, rise above marginal energy costs (enough to equate demand with the available supply). If this happens frequently enough, the present discounted value of expected future profits of building a new facility will exceed its costs—that is all the incentive a potential generation entrant needs and it will be built. If such circumstances are rare, then additional facilities are not needed. Getting these signals right is especially important as the grid smartens and short-term electricity storage technologies improve, and it becomes easier and easier to adjust through demand response rather than incurring the cost of additional generation. The same arguments hold for transmission upgrades like new lines when transmission services are priced competitively (and thus factored into the spot market energy prices at particular locational hubs). Thus the efficient level of transmission and generation resources would result simply as a consequence of providing competitive market signals. No separate pricing mechanism for capacity would be needed.

This would also simplify the problem of assigning marginal costs by time, as they would largely be a function of the prevailing spot market energy prices for the corresponding period. However, actual restructured markets usually do not have competitive transmission, and regulators usually are more comfortable with regulatory planning for capacity rather than pure market determination of it. The attendant capacity regulations often include financing mechanisms (e.g. special capacity markets with parties responsible for holding amounts as defined by regulatory rules) that are apart from short-run marginal energy costs, and one of the reasons used as a justification for caps on such spot market prices (in addition to other reasons like preventing the exercise of any market power that might arise, see Friedman 2009). In these actual systems that work to constrain spot energy prices, it is less obvious how to translate the non-energy costs into retail rates. There is a good case to be made that a substantial portion of these should be in the peak rates, and there is also a good case that sunk, historical costs are nonmarginal and should be part of the infrastructure fees.

Along these same lines, the case is also strong that hardly any of these capacity costs belong in off-peak retail rates, especially when much of the capacity isn't used at all during these hours. Electricity systems vary greatly from place to place, although most feature a strong imbalance between the quantity demanded during daily peak hours versus that demanded during off-peak hours. When there is a strong imbalance, then virtually all of the capacity charges would arise as scarcity rents during the peak hours.[15] The off-peak marginal cost of electricity is generally quite low and substantially below the off-peak rates that are typically charged in TOU plans; see the survey in Friedman (2011). In the April-June 2009 period, for example, this off-peak marginal cost in California (during 10PM-7AM) was $.022/kWh.

There is an important relation between the marginal cost and the definition of the time period for which it is defined. Most statistical reports that present peak and off-peak data use standardized definitions of peak and off-peak hours determined by the North American Electric Reliability Corporation (NERC). The NERC definition of peak hours is generally much broader (and the off-peak narrower) than those that utilities define for their residential customers, and this affects the calculation of marginal costs. For example, NERC peak hours for western states are 7AM-10PM Monday-Saturday except on designated holidays, and all other hours are off-peak. By contrast, practically no residential TOU plans consider Saturdays as on-peak hours, and the peak period generally ends before 10PM on weekdays. In California, for example, PG&E defines peak hours for residences as 12-6PM on non-holiday Monday-Friday, only 30 hours per non-holiday week compared to 90 peak hours for NERC. Similarly, SCE defines peak hours for residences as 10AM-6PM Monday-Friday, or 40 hours per non-holiday week. In the SPP experiment that generated our sample data, peak hours were defined as non-holiday weekdays from 2PM-7PM or 25 hours per nonholiday week. These differing definitions have important effects on how one estimates the marginal cost for the peak and off-peak periods. The marginal energy cost for an interval is closely tied to the weighted average spot price of electricity in the wholesale market during that interval. In particular, the marginal cost during the peak period goes up as one narrows the interval definition to the highest aggregate demand hours[16]; this is accompanied by a more graduated rise in the off-peak rates, as the least-expensive peak hours get redefined as off-peak and averaged in with a large volume of other hours.

For illustrative purposes we use the SPP definition of peak hours as 2-7PM on nonholiday weekdays, and I will use a marginal cost during the peak of $.30/kWh and a marginal cost during the off-peak of $.05

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[15] Technically the capacities of an electricity system are joint costs—costs that are incurred once but used to produce and carry different services, in this case electricity at different time periods. Thus the marginal cost of capacity is shared by the different services—peak and off-peak electricity—provided with it. Two factors work to minimize the share that should be assigned to off-peak service: the geographic broadening of the relevant market for transmission and generation, and the large demand differences for peak and off-peak electricity.

As our generation markets become geographically broader and more competitive, there is less need for new small peaking plants as other plants (and growing demand response programs) serving a larger area can fulfill peak demands at a lower cost. Competitive systems in effect now, like ISO-New England and PJM, determine capacity additions and competitive capacity charges purely as a function of peak-period demands. Additionally, because the demand for electricity is so much less during off-peak hours than it is during peak hours, and because the respective demands are highly inelastic, the appropriate share of capacity costs for off-peak hours is small. For example, peak demand in ISO New England during the first (winter) quarter has been between 21,000-22,000 MW in 2007-09 whereas the median load has been at 16,000 MW, and the off-peak load goes down to about 10,000 MW at the minimum (See p. 8 Figure 3 of ISO New England 2009 First Quarter Markets Report). Off-peak consumers should not be charged for the cost of intermediate-level and peaking plants that they do not use, nor extra transmission lines that they do not need. Off-peak users should pay some portion of the marginal cost of baseload capacity, but this marginal cost may be small if it is accompanied by a reduction in the need for intermediate and peaking capacities. Should there be a large increase in off-peak usage relative to the peak, perhaps because of a strong growth in off-peak charging of electric vehicles, then the share of capacity attributed to “off-peak” usage could increase (or equivalently, the number of hours considered off-peak could decrease).

[16] Aggregate demand means from all consumers including industrial and commercial, not simply total residential demand. The marginal cost depends on the whole-system demand as it affects particular locations (e.g. specific transmission lines), not on any single customer type.

per kWh. The relatively-narrow peak period works to create a relatively-high price ratio of peak to off-peak prices, and the specification also assumes that substantial capacity costs are assigned as marginal to the peak period. The off-peak rate is somewhat higher than in my survey because I am using a broader definition of off-peak hours (and an alternative design might include a "super-off-peak" to really take advantage of these low-cost times). Given that in our sample average monthly peak usage per household is 95.20 kWh and off-peak usage 448.09 kWh, this means average monthly marginal cost revenue is $50.96 or annual marginal cost revenue (MCR) is $611.52 per residence. Since the average "revenue requirement" in our sample is $71.72 per month or $860.64 per year (RR) , this means an average fixed fee of $20.76 per month (29 % of revenue) or $249.12 per year (FF) is needed in addition to the MCR.

The standard two-part tariff idea is simply to make the fixed fee uniform for all at $249.12 per year. However, in any system with MCR < RR, this will lead to substantially larger bills for low usage customers who had been paying the average (rather than marginal) price per kWh. That is, the customer at the mean annual peak and off-peak consumption amounts would pay the same, those proportionally above the means would have lower bills, and those proportionally below the means would have higher bills. Furthermore, since the mean annual total usage of 6519.5 kWh is above the median usage of 5493.6 kWh (a relatively small number of very high usage customers pulls the average up), then more people will experience bill increases than the number that will have bill decreases. It is easy to see why such a system would not be very popular with ratepayers. Indeed, Column 2 of Table 4 shows just this result. The rows of the table show the population ordered by the size of the bill difference, defined as the TOU bill minus the ordinary time-invariant bill. Thus the lowest percentiles are those with the largest bill decreases (the gainers) and the highest percentiles are those with the largest bill increases (the losers). Only the three lowest percentiles are instantaneous gainers, with the fourth percentile being mixed as within it the bill differences range from -$33.60 to +$43.07. Those above the 40th percentile are all instantaneous losers. The magnitude of the gains and losses are also striking.

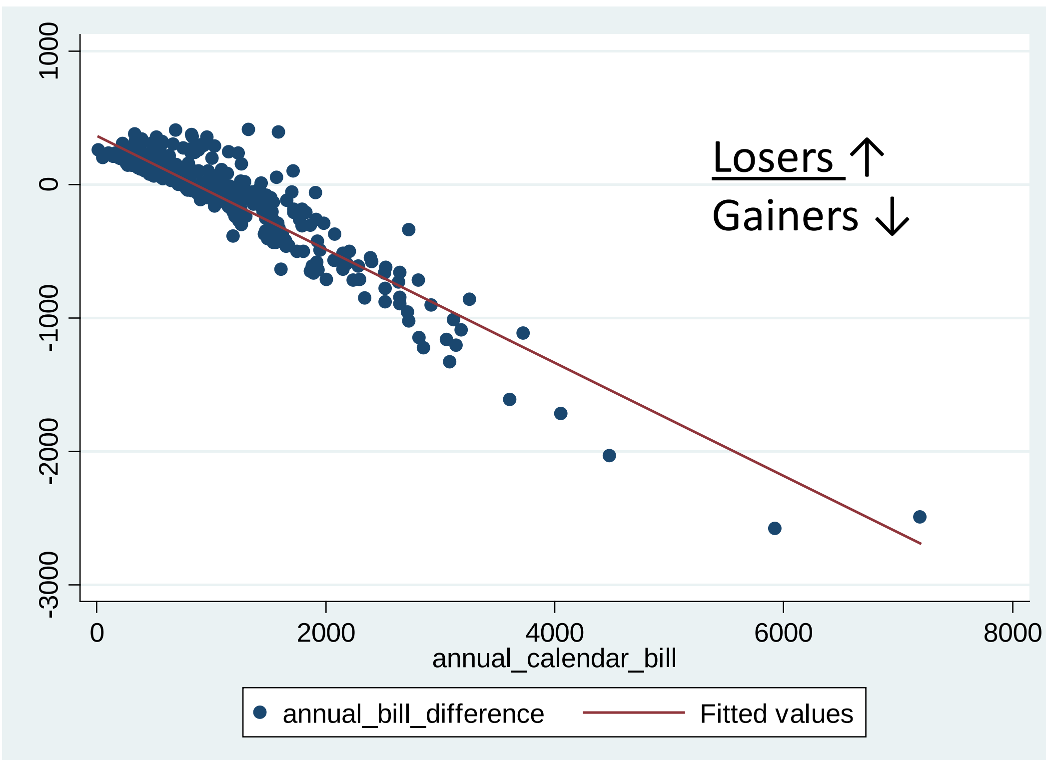
To put this in some perspective, Figure 4 shows a graph of the bill differences as a function of bill size. It is clear that the harm is greatest for those with the smallest bills, and lessens and then turns to a benefit as the annual bill size increases (this is also reflected in the negative coefficient of the equation for the fitted line shown under the graph). Figure 5 shows the percentile ranking of bill differences as a function of bill size, and shows a similar result: those in the highest percentiles (with the largest bill increases) are those with the smallest annual bills, and those in the lowest percentiles (the largest bill decreases) are those with the highest annual bills. Of course there is still variation that causes some to be gainers and some to be losers at any original bill size, because those with peak-intensive demands will have higher bills than those with off-peak-intensive demands.

Table 4: Annual Bill Differences Caused by Alternative Time-Varying Rate Designs

(=Time-Varying Bill – Time-Invariant Bill, Negative Numbers Gainers, Positive Numbers Losers)

Percentile	Uniform Fixed Fee	HOOP Proportional Fixed Fee	Percent Bill Change at Decile Median	HOOP Status Quo Equity Fee	Percent Bill Change at Decile Median
0-10	-748.17	-349.43	-16.99	-214.85	-13.93
10-20	-215.37	-78.77	-7.91	-67.61	-8.94
20-30	-64.27	-18.29	-2.51	-37.11	-6.47
30-40	13.90	6.11	1.45	-16.31	-3.60

40-50	75.33	23.66	5.73	-2.86	-.14
50-60	107.98	39.09	8.91	10.37	2.77
60-70	142.27	52.01	9.98	26.49	4.33
70-80	175.72	70.82	12.26	45.46	7.91
80-90	216.82	93.78	11.47	78.19	9.15
90-95	264.84	131.86	17.03	133.42	11.07
95-99	311.32	173.80	17.87	209.76	16.73
99-100	377.03	249.12	15.98	353.59	19.30

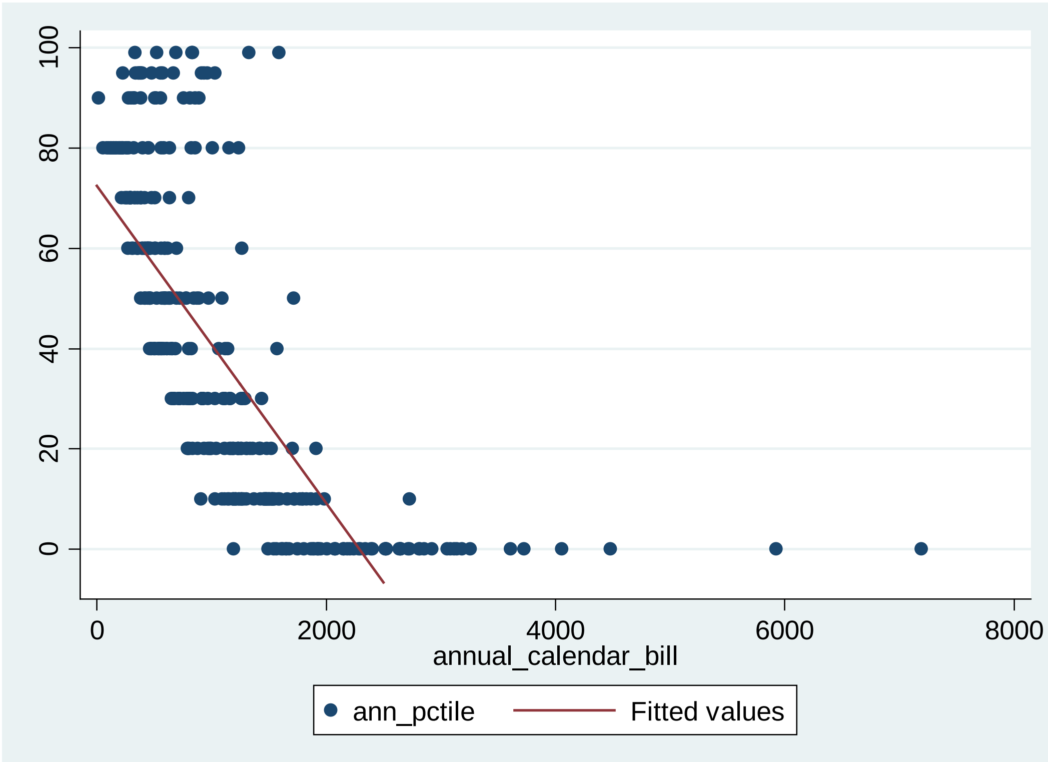


$Y = 366.0315 - .4252X \quad R^2 = .86$

(10.49) (.01)

Figure 4: Bill Differences with Uniform Fixed Fee as function of the original annual bill

(Bill difference is positive if TOU27 Bill > Original Bill)



$$Y = 72.4133 - .0315X \qquad R^2=.54$$
$$(1.75) \qquad (.00)$$

Figure 5: Bill Difference Percentile from Uniform Fixed Fee as a Function of the Original Annual Bill

However, let us now make use of the HOOP feature that assigns different fixed fees to different groups in accordance with equity considerations. We present here the results of two variations we have considered, one using the proportionality rule and the other using the status quo equity rule. In each of the cases presented, bearing in mind the wide distribution of usage levels shown in Figure 3, we categorize the sample population into 10 usage groups in increments of 2000 kWh as usage increases from 0 to 20,000 kWh annually. This covers 324 residences of the 331 in the sample, and leaves for exceptional treatment the 7 residences in the sample that have very dispersed usage levels from 20,000 up to the maximum of 43,361 kWh per year. In both cases, we treat these 7 residences as having their own individual fixed fees set at the level that keeps their bills constant if their consumption remains unchanged.[17]

We first consider the proportionality rule. It has a clear appeal to fairness in allocating the historical, fixed and nonmarginal assessments that customers are obligated to pay. While the fixed fee still averages \$249.12 annually (\$20.76 monthly) over the entire population, CARE residences are entitled to discounts. In the system used to determine their actual bills, CARE offers a 20% discount with no high-tier rates to qualifying low-income households, paid for by a rate surcharge on all other customers. CARE residences are estimated to comprise 14.94% of the population. To remain true to our "marginal

[17] This is equivalent to using the status quo equity rule where each of these extreme residences is in its own group of one. Other treatments are possible, but we think this one is the most realistic.

cost rates for all" principle, we will assign discounts to qualifying residences only through lowering their fixed fees (possibly to a negative value, or a credit), made up for by increasing the fixed fees of all other customers so that total fixed fees remain constant.

Total annual revenue from CARE customers in the sample is $ 25,879.03, and the marginal cost revenue from this group's usage is $26,402.65. To have the CARE group as a whole receive the same total discount under the HOOP plan, CARE customers must receive a rebate of $523.62 in the form of fixed fee credits. The non-CARE group contributed $258,967.88 in total revenue with marginal cost revenue based on its usage coming to $176,019.90, leaving $82,947.98 to be assessed in fixed fees. The proportional fee structure will be calculated separately for the non-CARE and CARE residences, each calculated to raise the correct fixed fee (or credit) totals. That is, fixed amounts will be assessed to each of the 10 usage groups in proportion to the mean usage level of the group. If usage group 2 has twice the average usage as does group 1, then the fee assessed to group 2 will be twice that of the fee assessed to group 1. Columns (2) and (3) of Table 5 shows the annual fixed fees and fixed credits assessed to each of the 10 groups for non-CARE and CARE residences respectively.[18] The non-CARE fees vary from $63 to $810 annually ($5.24 to $67.52 monthly), whereas CARE residences receive credits that vary from $3 to $32 annually ($.24 to $2.70 monthly).

The distributional consequences of using the proportionality rule are shown in Table 4 and Figures 6 and 7. Table 4 shows the bill differences ordered by decile from gainers to losers, and can be compared with the uniform fixed fee. It is clear that the bill differences are lowered dramatically, in all deciles up through 95 by at least half. These bill differences for deciles 10-90 are less than $100 per year, generally less than 10 % of the average bill. I have added a column that shows for each decile the bill difference of the median member of that decile as a percent of the original bill. Deciles 10-70 are under 10%, and the changes even at the extremes do not exceed 20%.

Figure 6 is analogous to Figure 4 and shows the bill differences caused by the proportionality rule as a function of the original annual bill. Observe that the trend line is now much flatter. While this is much less regressive than the uniform fixed fee case, it is still mildly regressive in that the gainers tend to be those who had the larger original bills. The slope of the trend line, shown in the regression equation underneath the figure, has changed from the -.425 of the uniform fee case to only -.119.

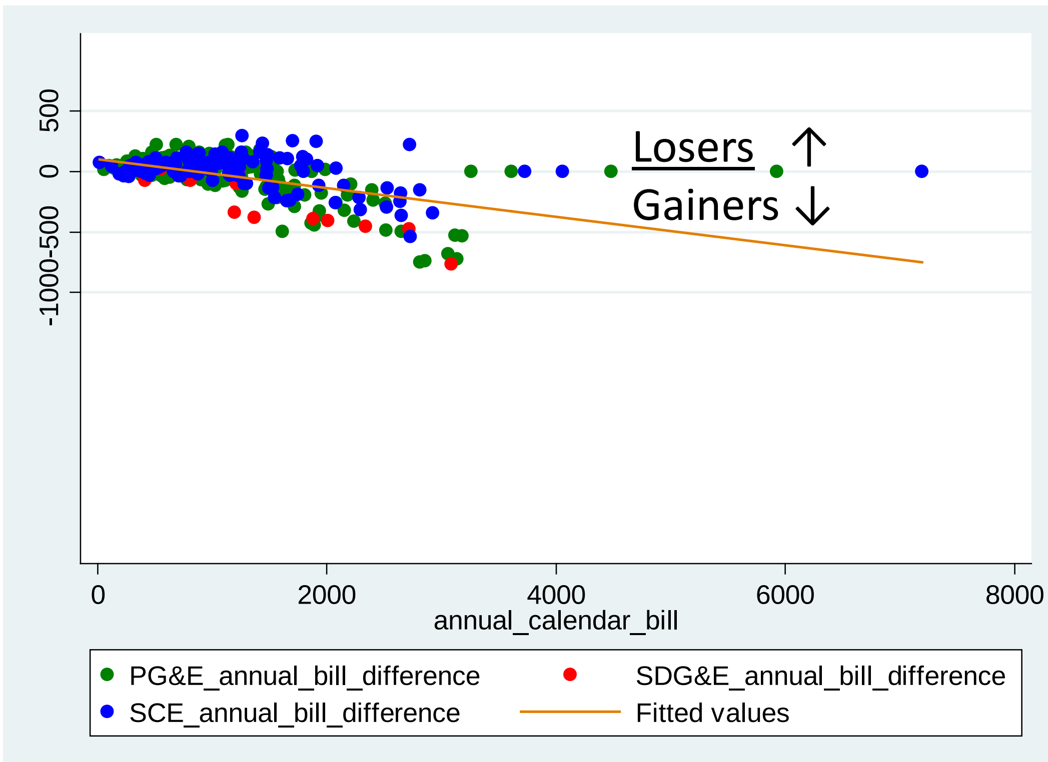
Table 5: HOOP Fixed Fees (revenue-neutral compared to time-invariant system and uniform annual fixed fee of $249.12)

Group (Annual kWh)	Proportional Fixed Fees (Annual Non-CARE)	Proportional Fixed Fees (Annual CARE)*	Status Quo Equity Fees (Annual Non-CARE)	Status Quo Equity Fees (Annual CARE)*
0-2000	62.85	-2.78	38.10	20.83
2000-4000	133.09	-5.88	96.46	-5.40
4000-6000	209.70	-9.27	152.84	-28.60
6000-8000	294.19	-13.01	263.72	-33.67
8000-10,000	385.85	-17.06	358.78	81.12
10,000-12,000	469.57	-20.76	533.35	-15.95
12,000-14,000	557.87	-24.67	677.82	8.32

[18] Please note that the CARE sample population is small, and there are few of these observations per group.

14,000-16,000	647.13	-28.61	965.57	259.81
16,000-18,000	732.24	-32.37	1149.97	12.74
18,000-20,000	810.28	--------	1202.96	-------

* Based on small CARE sample size, may not be representative. Status quo equity fees can be skewed because of very few CARE residences in a group.



$$Y = 102.1494 - .1186939\,X \qquad R^2 = .32$$
$$\quad (10.40) \qquad (.01)$$

Figure 6: Graph of Absolute Bill Differences caused by HOOP Proportional Fee[19]

Figure 7 is analogous to Figure 5 and shows the percentile of the bill difference as a function of the original calendar bill. Again the trend line is substantially less steep than in the uniform fee case, and its slope has flattened from -.0315 to -.0149. Also, the adjusted R^2 has decreased substantially from .54 to .12.

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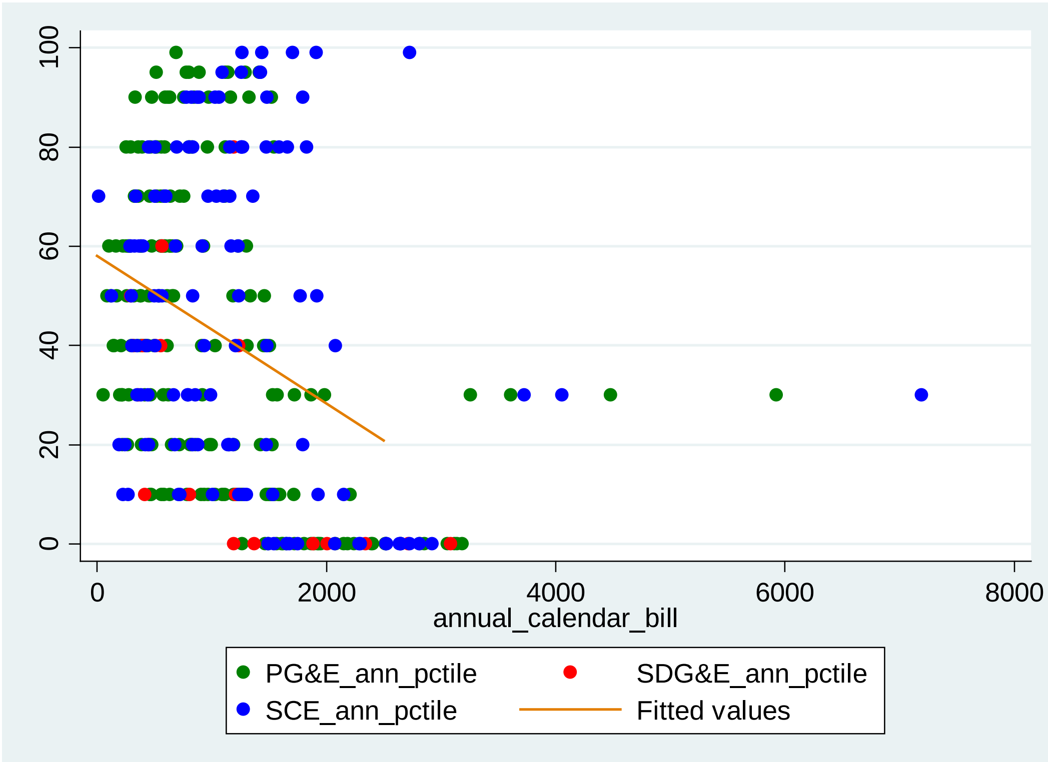
[19] 10/21/11.



Y = 58.09677 - .0148687 X $\quad$ R^2 = .12

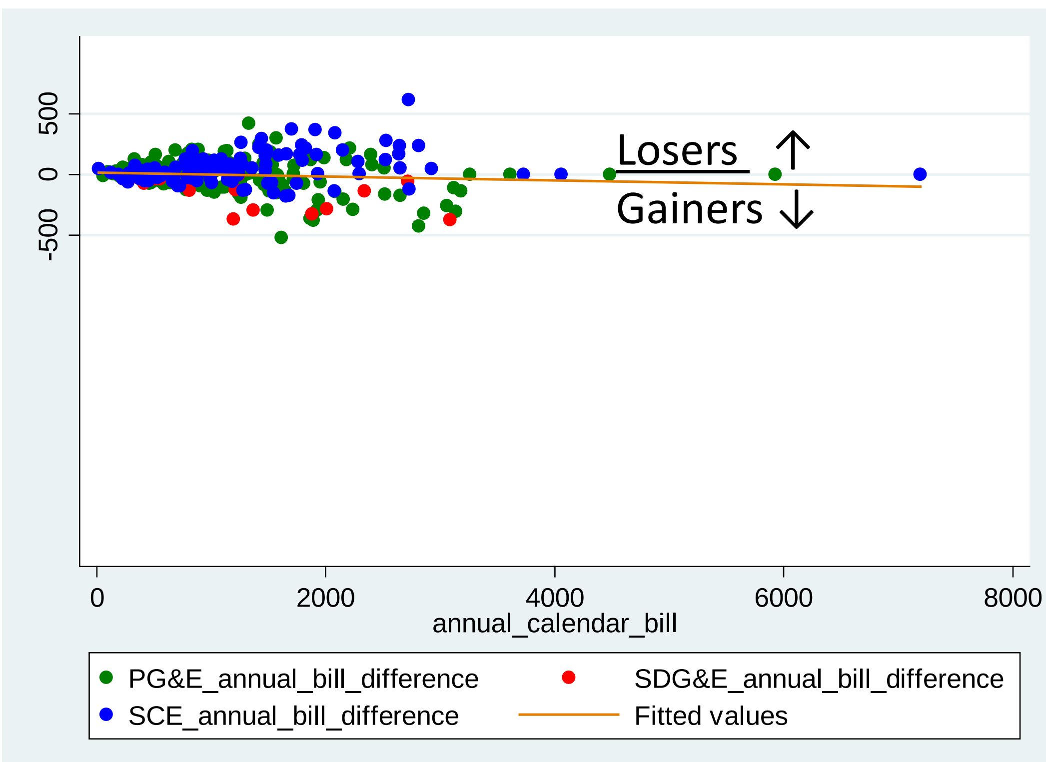
(2.44) $\quad$ (.00)

Figure 7: Bill Difference Percentile from the HOOP Proportional Fee as Function of the Original Bill

While the proportional rule for fixed fee assignment may be quite equitable in the judgment of some, it is clear that some important bill differences are still caused by applying that system to California residences. It is highly likely that the same system, if recalculated by the utilities independently for each of its current climate zones, would greatly decrease the bill differences from those observed here. But the mild regressive trend would remain. The reason is simple: the current California system of rates is not proportional but it is progressive: higher usage customers face greater marginal and thus greater average prices than lower usage customers. Furthermore, the increase in marginal price becomes quite substantial in the higher tiers. In response to the argument that the proportional rule is “fair”, one might say that the status quo system already embodies the degree of progressiveness that is considered fair in California. A different equity rule designed to replicate closely the distribution of whatever system it is replacing is that of “status quo equity” where each group contributes exactly the same revenue as it is contributing under the status quo (and further, CARE households within a group would also contribute the same revenue as under the status quo). That is, the fixed fee for a group is calculated as its total revenue under the current system minus its marginal cost revenues, divided by the group size. We calculate the HOOP fees that would be assigned to the same 10 groups under this rule.

The last two columns of Table 5 show the status quo equity fees. Comparing the non-CARE fees from the proportional and status quo equity rules, in this case the status quo equity rule is more progressive in the sense of assigning higher fees to higher usage residences. These fees range from $38 to $1203 annually ($3.18 to $100.25 monthly). While I have included the CARE fees for completeness, the very small number of observations per group means they cannot be taken as representative of the population of CARE residences in these groups. Indeed, the lack of pattern to these fees is undoubtedly due to this factor.

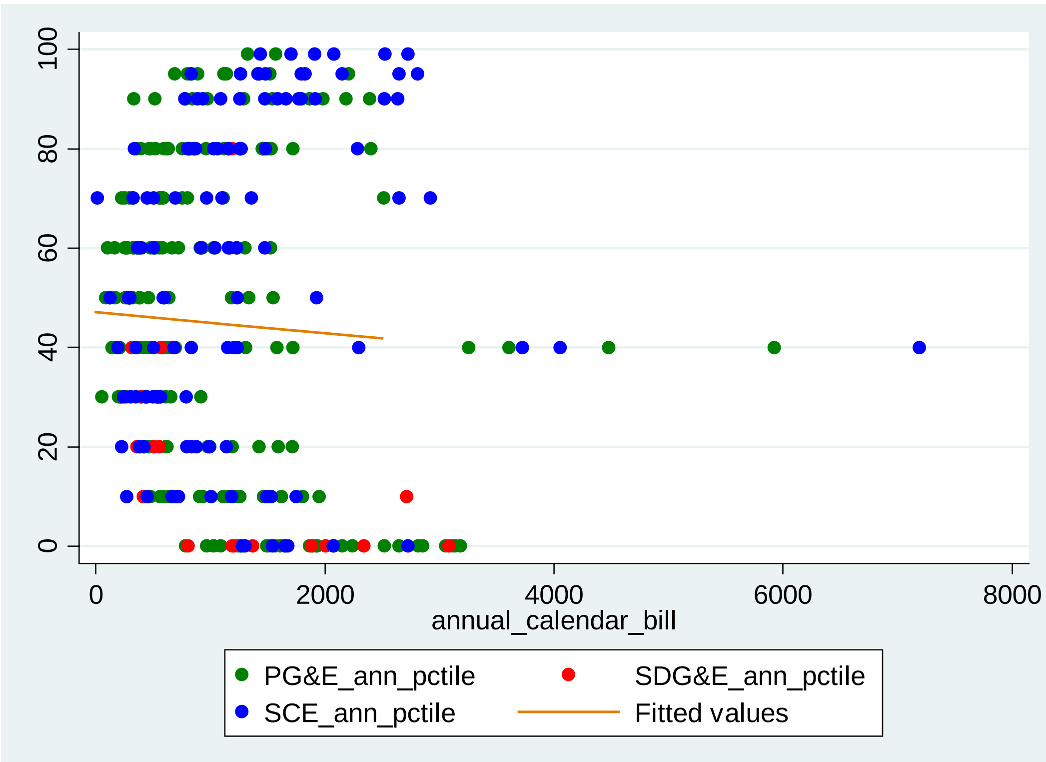
The last two columns of Table 4 show the annual bill differences caused by the status quo equity HOOP plan compared to the original bills. Again, these are ordered with the lowest deciles being the largest gainers and the highest deciles the largest losers. The absolute bill differences, measured by the mean for each decile, are generally smaller than those from the proportional plan. The proportion of the population that are instantaneous winners (i.e. before any behavioral change) is substantially greater: the first 50 percent of the population, compared to only the first 30 percent for the proportional plan. The last column shows the bill difference as a percent of the original bill at the median for each group. These bill differences are less than 10% for deciles 10-90, and generally smaller than those for the proportional plan. As suggested earlier, it is highly likely that each utility can tailor such a plan independently for each climate zone, and thus make the bill differences substantially smaller than the still modest differences shown here.



Annual_bill_difference = 14.5227 - .0159069*Annual_calendar_bill R2 = .01
(9.42) (.009) n = 331

Figure 8: Bill Differences caused by the HOOP Status Quo Equity plan as a function of the original bill

Figure 8 shows the bill differences from the status quo equity plan as a function of the original annual bill, analogous to Figure 4 for the uniform fee plan and Figure 6 for the proportional fee plan. With status quo equity, essentially there is no relationship between the bill difference and the original bill—the trend line is almost perfectly flat. This shows up as the insignificant slope coefficient of -.016 in the regression equation, as well as the adjusted R^2 of only .01. Figure 9 (analogous to Figures 5 and 7) shows the percentile of the bill difference as a function of the original bill. Again, essentially there is no relation—the -.002 slope of the trend line is insignificant and the adjusted R^2 is .00.



Percentile of Bill Difference = 47.0962 - .0021064*Annual_calendar_bill $\qquad R^2 = .00$

(2.60) (.002) $\qquad$ n = 331

Figure 9: Bill Difference Percentile from HOOP Status Quo Equity Fees as Function of the Original Bill

In sum, both HOOP rules of proportionality and of status quo equity can be used to design practical, fair and efficient systems of time-varying prices that can and should be attractive to large numbers of residential electricity customers. While our sample size limited the ability to tailor the fixed fee structures to particular climate zones, there is nothing to prevent utilities from doing exactly this. Thus the quite modest bill differences we have found could be made even more modest by the utilities. These HOOP plans feature marginal-cost based rates that allow off-peak electricity prices to be lowered to their marginal costs, a very important feature for achieving greenhouse gas reductions through vehicle electrification. They also are plans that will encourage demand responsiveness as the grid smartens and makes residential customer responses easier and more automated (e.g. smart appliances that work less hard during peak hours unless instructed otherwise).

IV. Issues in the Design of HOOP Rates

One general issue in the design of HOOP rates is the importance of choosing group assignments that are very difficult for a user to alter by simple changes in behavior. That is one reason for suggesting that the group assignment be based upon long historical patterns for the unit, like a three-year historical average for residences that have been served for that period or longer (even if by a different occupant). This also can be very useful for behavioral reasons—the fixed assessment can be clearly separated on the bill from any charges that have to do with current consumption, so that consumers are more likely to recognize the current bill impact of any changes in usage that they are considering. For similar reasons, the length of the usage interval within which the fee does not change should be broad enough so that relatively small changes rarely cause a shift into a different group—if the interval definitions were very narrow and reassignment quick, the system would begin to approximate average cost time-of-use pricing rather than the HOOP requirement of marginal-cost based rates.

A procedure would be necessary for establishing the correct group assignment for new residential units. This could be done on an interim basis, perhaps based for the first three months on an estimate made by the service provider at the start of service, then adjusted based on the usage pattern of the first three months, with the second year's fixed fee based upon the first year's usage, and the third year based on the average of the first two years. These start-up procedures should be accompanied by clear written explanations to the customer of the overall fixed fee structure and the process of assignment that is being followed.

Another issue in the design of HOOP rates is the treatment and effect of major changes in electric usage at an existing residence, such as those caused by major remodeling, the purchase of an electrically-fuelled vehicle (EV) or a photovoltaic (solar) installation (PV). If these changes are not treated other than through their effects on usage, the marginal effects would be visible right away but the longer-term effects on the fixed fees would be much less visible. The EV would increase the monthly costs and quite possibly the fixed fees (with a long lag), while the PV is just the opposite. The effect of the EV on fixed fees is not likely to be great. For example, an EV with current technology gets about 4 miles per kWh, so a car driven 10,000 of these miles per year would increase electricity usage by 2500 kWh. In our examples with usage grids 2000 kWh wide, the purchase and use of such a vehicle would eventually move about 75% of residences to one higher usage category and 25% up two categories. Given that category increases are roughly $100 each in annual fixed fees, the expected fee increase would be $125 (for simplicity not discounting for the lag). If the electricity itself is purchased in the off-peak period, it would cost $125 in energy costs, or a total increase of $250 per year (compared to $750 at the third tier of the current time-invariant system, or $500 if on the third-tier of the special E-9 EV schedule of PG&E). Of course this would be substituting for gasoline that at 25 miles per gallon would be 400 gallons. At the rough current price of $4 per gallon, that is $1600 avoided. Potential EV owners will consider if a savings like this (substituting their own expected driving) is enough to offset the extra capital cost (primarily the battery) of the EV.

While savings like those illustrated above may be sufficient to induce many people to purchase EVs (and similarly PVs that would be reducing the most expensive peak use of electricity), there is the further issue of whether having an EV or PV might entitle the residence to a more favorable fixed fee. That is, the current system subsidizes things like living in the desert and having all-electric heating by providing more generous baseline quantities for residences with these characteristics. A public utilities commission switching to a HOOP system could continue such subsidization in its more efficient manner of a lower fixed fee assessment, keeping all customers facing the same time-varying rates set at marginal cost levels. Then it would seem natural to consider whether the EV or PV should similarly receive favorable treatment.

A final issue to mention is the possibility of phasing in HOOP rates as time-invariant rates are simultaneously phased out. The advantage of the more gradual phase-in (and phase out) period is that it can be an important way of further reducing any instances of bill shock while at the same time helping customers to understand the new system. For example, a public utilities commission might order that time-invariant rates be phased out over a four-year period to be replaced with the customer's choice of a HOOP plan (from among several that might vary in how dynamic they are as well as their interval definitions of peak and off-peak periods). In the first year, the customer's bill would be 25% based on HOOP and 75% based on the old time-invariant plans. Then the second year would be 50-50, the third year 75-25, and the fourth year 100% HOOP. This might not be necessary, and it could create a few problems of its own (e.g. customers whose bills will be somewhat lower under the HOOP system might complain). But if this is thought necessary or desirable to mitigate distributional concerns, it is a small price to pay for a system that has critical efficiency and environmental advantages over the prevailing time-invariant rates and offers distributional fairness as well.

VI. Summary and Conclusions

Workable, fair and efficient time-varying rate structures can and should replace the outmoded time-invariant structures that are prevalent today. There is a huge disconnect between the very high off-peak rates that almost all residential consumers face today and the marginal cost of providing that off-peak electricity. This discrepancy, for example, causes a substantial and inappropriate deterrent to the reduction of greenhouse gases through vehicle electrification, when there are abundant off-peak electrical resources that could be substituting for petroleum combustion in vehicles. A smartening grid has the technology to ease and to automate much more voluntary demand responsiveness of residential users, if only the right price signals can be sent.

But many consumers resist time-varying rates. Since the 1970s we have undertaken numerous experimental and pilot projects with these rates and many electricity retailers offer them as an option. Yet as of 2010 no more than 1 percent of U.S. residential customers have chosen to be on such rates. Organized consumer groups show resistance to more widespread use of time-varying rates because of distributional concerns that vulnerable populations will be made worse off by them. Indeed, there has not been much effort made to offer time-varying rates that are attractive to large numbers of residential customers.

I consider a family of time-varying rates that have two characteristics: (1) they utilize marginal-cost based rates for all of the time-varying charges, and (2) they ensure the correct total revenue is paid by the assignment of customers to broad groups and the assessment of a fixed infrastructure charge to each group whose magnitude is determined by equity principles. I refer to such rates as Household On and Off Peak (HOOP) plans. These plans can include all types of time-varying rate designs, from the straightforward peak and off-peak distinction to much more dynamic versions. I examine simple versions of these plans on a representative statewide sample of 331 California residences that features a full calendar year of usage data for each residence for every 15 minute interval within the year. This is an especially interesting sample because of its detailed round-the-clock usage information representative of a large population—to my knowledge, the first of its kind.

I use this data to compare the actual time-invariant bills of these residences with those generated by several HOOP plans. I utilize two alternative equity principles to illustrate the distributional consequences. One is a simple proportionality rule, in which each of the HOOP groups is assigned a fixed fee that is proportional to the mean usage within the group. The other rule is that of "status quo equity," in which each HOOP group is assigned a fixed fee so that the total revenue collected from that group is exactly the same as the total revenue it provides under its actual time-invariant plan. These illustrate definitions of equity that are likely to be appealing choices for many jurisdictions.

The definition of groups under HOOP plans is a key part of the design, as the definition must be one that makes it very difficult for a residence to change its assigned group by its short-term behavior. That is why I suggest assignment into fairly broad usage groups with the assignment based upon a three-year historical average. For the empirical exercise illustrated here, I chose 10 usage groups each spanning a 2000 kWh interval per year. Despite the complexity of the systems used by the three California utilities—a complexity that can lead to over 40 different bills for the identical usage within just one of the utilities—a simple statewide proportional plan was able to keep the bill changes for 60 percent of the population under 10%, with the rest under 20%. The status quo equity plan did even better, with 80% of the population under 10% and the rest under 20%. Furthermore, this plan was neutral in terms of its impact on those with small and large bills—there was no relationship between the bill difference caused by the plan and the size of the original bill. While the size of the sample does not permit forming these groups within any particular climate zone, there is nothing to prevent the utility companies from doing that and thus tailoring the systems to reduce bill differences substantially further.

Thus I conclude that HOOP time-varying rate designs can be made attractive to almost all consumers. They offer the promise of practical, fair and efficient rate plans that allow us to take advantage of the smarter grid of the twenty-first century and to address important environmental issues that need to be addressed soon. I hope that the work herein will stimulate further consideration of such plans, and will help to improve and to speed the implementation of them.

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