The Value of Dynamic Pricing in Mass Markets

The simpler forms of dynamic pricing, in which prices vary only during extreme supply conditions, may capture many of the economic benefits of real-time pricing, and may be suitable for wide-scale deployment to mass-market consumers, for whom dynamic pricing options have largely been ignored.

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I. Introduction

Many states have restructured their power markets during the past few years. However, a major weakness of most market designs continues to be the absence of demand response in retail markets. Commissioner William Massey of the Federal Energy Regulatory Commission (FERC) noted this omission recently:[1]

> Demand responsiveness is critical to a good market, but is generally not present in most electricity markets. This is not because demand is truly inelastic, but . . . because consumers do not have the opportunity to react to prices. This has to change [because] increasing demand responsiveness is good for markets and good for customers . . . It is up to the states to facilitate both the right price signals reaching customers and customers ability to react to those signals.

As if seconding this viewpoint, the chairman of the Colorado Public Utility Commission, Ray Gifford, observed: ''If retail electricity prices reflected the cost of power, a demand-side response would bring the market back to equilibrium, dampening both high prices and volatility. Utilities and regulators need to implement real-time, time-of-day, and inverse-block pricing. Sending the right price signals is the rational, cheapest, and best way to conserve energy . . . and save the expense of unnecessary generation . . .''[2]

While analyzing the meltdown of California's electricity market during 2000–2001, EPRI researchers found that one of the key factors was the near-total absence of demand response in California's restructured market.[3] This lack of demand response in California, and in most electricity markets worldwide, can largely be remedied with economically rational pricing. The traditional flat tariff, based on average cost of service, is offered to nearly all mass-market consumers. It fails to provide any economic incentive for consumers to shift load away from higher-priced supply periods. Nor does hourly pricing based on assigned load profiles, a popular practice for small consumers in restructured markets.

Traditional time-of-use (TOU) rates, in which electricity prices vary across time periods within a day and, perhaps, seasonally, are a significant improvement over flat tariffs. TOU rates provide consumers with an economic incentive to reduce usage during high-priced periods and to shift load from high-priced to lower-priced periods. However, even TOU rates do not recognize the inherent uncertainty in supply costs, since they are designed to reflect prices under expected, long-run conditions; they do not reflect the volatility and inherent uncertainty associated with electricity supply. Thus, TOU rates either expose utilities to supply cost risk, or force utilities to lay off that risk through hedging, through traditional supply-side alternatives such as the construction of peaking units, or through standard load-management programs such as direct load control. TOU rates do not give consumers the opportunity to mitigate price risk on the customer side of the meter, or to avoid the potentially higher costs of traditional risk mitigation methods. Only dynamic pricing creates this opportunity for consumers.

EPRI researchers found that a key factor was the near-total absence of demand response in California's restructured market.

Dynamic pricing refers to any electricity tariff that recognizes the inherent uncertainty in supply costs. One example is a tariff where price levels are established ahead of time, but the timing when these prices are in effect is unknown. An example is the critical peak pricing tariff currently offered by Gulf Power, where a price of $0.29/kWh can be charged during the peak-price period for up to 1 percent of the total hours in a year, but neither the consumer or the utility know when these high-priced hours will occur until 24 hours prior to their implementation. Another form of dynamic pricing is where both price levels and timing are unknown, but the time blocks within a day when prices change from one level to another are known. An example is Puget Sound Energy's proposed adjustable rate tariff, where prices vary daily within known time periods for a portion of participating customers' loads.[4] Still another example of dynamic pricing is real-time pricing, where price levels, time periods, and timing are all variable.

Few would disagree that dynamic pricing offers significant opportunity to reduce market-clearing prices in competitive markets and to lower supply-side costs and cost-risk for regulated utilities. However, with a few notable exceptions, dynamic pricing has only been implemented for large commercial and industrial (C&I) customers. Perhaps the best example is Georgia Power's program, where more than 1,600 customers face hourly prices and provide verifiable load reduction totaling 850 MW.[5] While large consumers represent a valuable market for obtaining the economic benefits of dynamic pricing, so do residential and small commercial and industrial customers. In fact, mass-market consumers constitute the bulk of utility customers, and may account for as much as two-thirds of energy sales.

There are two primary reasons why dynamic pricing for mass-market consumers has largely been ignored to date. One is the belief by many policy makers that small consumers will not shift usage in response to time-varying rates. The second is the belief that, even if consumers will shift some load, the resulting benefits will not be sufficient to offset the costs of implementing TOU or dynamic pricing. The remainder of this article addresses these concerns.

II. Do Mass Market Consumers Respond to Changing Prices?

The price elasticity of demand can be used to estimate changes in consumer electricity usage in response to a shift from flat rates to TOU or dynamic pricing. The price elasticity of demand is a measure of the extent to which quantity demanded responds to a price change, other things equal. It is a unit-less coefficient, obtained by dividing the percentage change in quantity demanded by the percentage change in price.

Since consumers purchase multiple goods or services, several price elasticities of demand can be defined. When the price change of a particular good or service is compared with the quantity change in that same good or service, we obtain the *own-price* elasticity of demand for that good or service. On the other hand, when the price change in one good or service is compared with the quantity change in another good or service, we obtain the *cross-price* elasticity of demand. A related concept is the *elasticity of substitution*, which is the ratio of the percentage change in the ratio of the quantities of two related goods or services to the percentage change in the corresponding price ratio.

One reason dynamic pricing has been ignored in the mass market: the belief that small customers will not shift usage in response to time-varying rates.

There have been relatively few empirical studies on the impact of dynamic pricing for mass-market consumers. However, there is a large literature focused on price elasticity estimates for traditional TOU rates. These estimates can be used to predict responsiveness from dynamic pricing, since many forms of dynamic pricing simply expose consumers to higher prices during specific time periods. When such prices are in effect, these estimates can be used to estimate changes in usage by comparing the higher dynamic price with the base price in the same manner that TOU impacts are estimated by comparing the higher peak-period price with the base price. Consequently, we first provide a brief survey of the literature on traditional TOU pricing followed by a summary of studies examining dynamic pricing for mass-market consumers.

III. Traditional TOU Rates

Much of the literature on TOU rates stems from 16 demonstration projects involving 15 pricing experiments that were conducted in the United States under the auspices of the Federal Energy Administration (later Department of Energy). Ten of these projects were initiated in 1975 and a second batch of six in 1976. Researchers have focused on 12 of the 15 experiments. These 12 experiments involved approximately 6,700 customers, of whom about 75 percent were on some type of TOU rate. Experimental duration varied from six months to three years, and covered the period from October 1975 to February 1981.

Five experiments featured a single TOU rate, and were conducted in Arkansas, Connecticut, North Carolina (Blue Ridge Electric Membership Cooperative), Ohio, and Rhode Island. These experiments did not allow for estimation of price elasticities, but did yield estimates of load impacts caused by the specific TOU rate. The remaining seven experiments featured multiple (from 4 to 34) TOU rates, allowing for the estimation of price elasticities. They were conducted in Arizona, California (Los Angeles Department of Water and Power and Southern California Edison), North Carolina (Carolina Power & Light), Oklahoma, Puerto Rico, and Wisconsin. Five of the seven are of sufficiently high quality to yield unbiased estimates of price elasticities of demand by time of use. These experiments, which were mandatory in nature, were conducted in Arizona, California, Connecticut, North Carolina, and Wisconsin.[6] A variety of researchers, using a wide range of modeling methods, have estimated price elasticities of demand from these experiments.[7]

EPRI commissioned a study in the early 1980s to review whether it was feasible to estimate a model that pooled the data from these five high-quality experiments. The EPRI researchers found that results were remarkably consistent across the experiments, once adjustments were made for a variety of conditioning factors such as weather and demographic and appliance ownership characteristics. The estimated elasticity of substitution was −0.14, indicating that a doubling of the on-peak to off-peak price ratio would result in a drop of 14 percent in the corresponding quantity ratio. The elasticity of substitution varied with the presence or absence of major appliances in the household portfolio of appliances. Thus, households that had no major electric appliances had an elasticity of substitution of −0.07. At the same time, households with all major electric appliances had an elasticity of substitution of −0.21.[8] The elasticity of substitution is closely related to the own-price elasticity of demand; an elasticity of substitution of −0.17 is approximately consistent with an own-price elasticity of on-peak energy usage of −0.3.[9]

Two more recent studies have produced similar results.

Studies find that price-responsiveness is significantly less for small and medium C&I customers than for residential consumers.

One study examined the impact of TOU pricing at Salt River Project, where more than 100,000 consumers participate in that company's voluntary rate program.[10] This study examined the price elasticity associated with coincident peak demand, not just peak period usage. Kirkeide found that the price elasticity of peak demand with respect to the price of on-peak period electricity is −0.28.

A much more recent study is based on the nation's largest pilot program still underway at Puget Sound Energy.[11] About 240,000 customers have been moved from a flat rate to a three-part TOU rate, but they can opt out of the TOU rate.[12] Under this tariff, on-peak prices are 15 percent higher than the intermediate period price and off-peak prices are 9 percent lower. PSE has been tracking the impact of these rates on usage by time period since June 2001. The impacts vary monthly, with peak usage reductions ranging from a low of around 4 percent in the summer to a high of 6 percent in the winter (PSE is a winter-peaking utility). The PSE pilot program design does not allow for estimation of price elasticities, since only a single price is employed. However, the percentage changes reported above are consistent with an own-price elasticity of demand between −0.20 and −0.33 for both the on-peak and off-peak periods combined with cross-price elasticity values indicating that usage in some periods is complementary to usage in other periods but a substitute for usage in different periods.

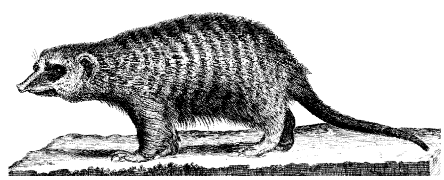
Comparatively few studies exist on the price elasticity of demand for C&I consumers. These studies find that price responsiveness is significantly less for small and medium C&I consumers than it is for residential consumers. Two studies of note were done on consumers from Southern California Edison (SCE) and Pacific Gas and Electric Company (PG&E), both located in California.[13] The SCE study found that the average own-price elasticity for consumers with demands below 500 kW ranged from −0.033 to −0.035. For consumers at the higher end of this market segment, with demands between 200 and 500 kW, the elasticities were larger, ranging from −0.87 to −0.92. The PG&E study found that own-price elasticities ranged from −0.019 to −0.038. Both studies indicate that elasticities tend to be highest during on-peak periods, followed by intermediate and off-peak periods. Cross-price elasticities are positive, but substantially lower in absolute value than own-price elasticities.

IV. Dynamic Pricing and Enabling Technologies

Recently, a number of utilities have experimented with dynamic pricing options, sometimes in conjunction with enabling technologies that automate customer response during high-priced periods. As seen below, dynamic pricing, especially when combined with enabling technologies, can produce much larger reductions in peak demand than traditional TOU rates.

Two utilities, GPU and American Electric Power, conducted small-scale pilot programs using a two-way communication and control technology called TransText. The TransText device allows for the creation of a fourth, critical price period in which the price of electricity rises to a much higher level (e.g., 50¢/kWh in the GPU pilot). The number of hours during which this price can be charged is small (e.g., 100–200 hours) and the customer knows what the critical price will be ahead of time, but does not know when the price may be called.

The TransText device incorporates an advanced communication feature that lets consumers know that a critical period is approaching and it can



be programmed so that the consumer's thermostat is automatically adjusted when prices exceed a certain level. Using this technology, American Electric Power (1992) found significant load shifting, with estimated demand reductions of 2–3 kW during on-peak periods and of 3.5–6.6 kW during critical peak periods.[14] These critical peak reductions represented almost 60 percent of the consumer's peak load during the winter period. The GPU experiment produced similar results, showing elasticities of substitution that ranged from −0.31 to −0.4, significantly higher than the elasticities associated with traditional TOU rates.[15]

Another example of mass-market dynamic pricing is provided by Gulf Power Company's *Good Cents Select* program.[16] Like the GPU experiment, the Gulf Power program uses dynamic pricing to obtain additional benefits beyond traditional TOU pricing. Under this voluntary program, residential consumers face a three-part TOU rate for 99 percent of all hours in the year, where the peak period price of $0.093/kWh is roughly 60 percent higher than the standard tariff price and approximately twice the intermediate price. For the remaining 1 percent of the hours, Gulf Power has the option of charging a critical period price equal to $0.29/kWh, more than three times the value of the peak-period price. The timing of this much higher price is uncertain. In conjunction with this rate, participating consumers are provided with a programmable/controllable thermostat that automatically adjusts their heating and cooling loads and up to three additional control points in the home, such as water heating and pool pumps. The devices can be programmed to modify usage when prices exceed a certain level.

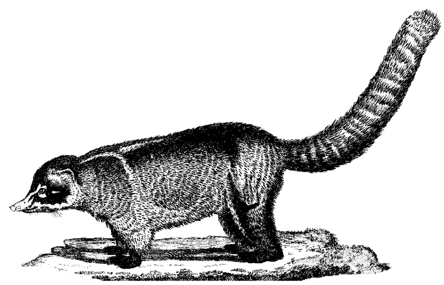
Gulf Power is seeing results similar to those of the GPU experiment. Peak-period reductions in energy use over a two-year period have equaled roughly 22 percent compared with a control group, while reductions during critical-peak periods have equaled almost 42 percent. Diversified coincident peak demand reductions have equaled

2.1 kW in the summer and 2.7 kW in the winter. This voluntary program has been in place for less than a year and Gulf Power has already signed up more than 3,000 large-use customers. It hopes to attract 40,000 customers over the next 10 years, representing about 10 percent of the residential population. Participating customers pay roughly $5/month to help offset the additional cost of the communication and control equipment. In a recent survey, the program received a 96 percent satisfaction rating.

Still another example of dynamic pricing is provided by *Electricite de France's* (EdF) Tempo program, which has been in place since 1996. As described by EdF researchers, the program features two daily pricing periods, on-peak and off-peak.[17] It also features day-of-the-year pricing. The year is divided into three day-types. ''Blue days'' are the most numerous (300) and least expensive; ''white days'' are the next most numerous (43) and mid-range in price; and ''red days'' are the least numerous (22) and the most expensive.

EdF does not offer a fixed calendar of days, but customers can know what pricing color will take effect the next day by checking a variety of different sources:

- consulting the Tempo Internet Web site;
- subscribing to an email service that alerts them of the colors to come;
- using Minitel (a data terminal particular to France, sometimes called a primitive form of Internet);
- using a vocal system over the telephone, or
- checking an electrical device (Compteur Electronique) provided by EdF that can be plugged into any electrical socket.



The Tempo rate was preceded by a pilot program, in which prices were quite a bit higher than those that were ultimately implemented. The pilot program yielded price elasticities of −0.79 for on-peak usage and −0.18 for off-peak usage.[18] There was no significant variation in elasticities across day types. On-peak and off-peak usage were determined to be substitutes, but the estimated cross-price elasticities were small. In absolute terms, the value for the on-peak elasticity was substantially higher than values found in the U.S. However, the value is similar to estimates for Swiss households: a short-run own-price elasticity of −0.6 during the on-peak period and −0.79 during the off-peak period.[19]

V. Summary of Price Elasticity Literature

It is clear from the above survey that mass-market consumers respond to TOU and dynamic pricing tariffs. Elasticity estimates are robust across a wide range of studies.[20] Additional conclusions are:

- The demand for electricity by time-of-use is inelastic in the short run.
- Dynamic pricing tariffs show much larger changes in usage than do traditional TOU rates, especially when combined with enabling technology such as two-way communication and programmable/controllable thermostats.
- Own-price elasticity of demand for on-peak usage is typically larger than the own-price elasticity of demand for off-peak usage.
- Price elasticities will be higher for households that have central air conditioning systems than for households that don't.
- Price elasticities for residential consumers are significantly larger than for small to medium-size C&I consumers.

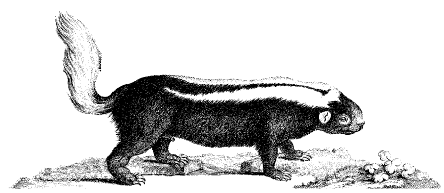
VI. Is Dynamic Pricing Cost-Effective?

While it is clear that mass-market consumers respond to price signals, there remains the key policy question whether implementation of dynamic pricing is cost-effective in light of the incremental metering, billing, and other related costs required to implement such tariffs. The remainder of this article presents results from three case studies that we have conducted recently.

We evaluated three different rate designs for utilities A and B and two for utility C. One is a traditional TOU rate, with four-time blocks and three price levels. Prices vary seasonally. A second rate is a critical peak-pricing (CPP) design very similar to the Gulf Power rate. The CPP rate includes a traditional TOU rate combined with a critical price that is applied to the peak and shoulder time blocks for up to 10 days a year, the timing of which is unknown. The third rate, extreme day pricing (EDP), charges a high price for all 24 hours during 10 critical days, and a low price for all hours on the remaining 355 days.[21] In order to assess the maximum benefit that could be achieved from more economically efficient pricing, we assumed that each rate would be mandatory for all customers.[22]

In order to place the analytical results in perspective, it is useful to understand the characteristics of the customers and utilities examined, since the benefits of alternative pricing options will vary with these characteristics:

- *Utility A*: About 900,000 residential customers; winter peaking system with very cold winters and humid summers; high air conditioning saturation; relatively tight supply market with higher marginal energy costs than the other two examples; fixed network, radio frequency automated meter reading (AMR) system already in place; incremental meter reading and data management costs to support TOU and dynamic pricing options equals about



$0.75/customer/month; the ratio of the CPP price to the base price equals roughly 2.75 and the ratio of the peak-period price to the base price equals 1.60.
- *Utility B*: About 1.2 million residential and small to medium C&I customers; summer peaking system with cold winters and mild, dry summers; low saturation of air conditioning; relatively low marginal energy costs; low-cost existing metering operation; estimated incremental capital and operating costs for new AMR system between $1.60 and $3.00/customer/month; the ratio of the CPP price to the base price equals roughly 3.4 and the ratio of the peak-period price to the base price equals 1.75.[23]
- *Utility C*: About 1 million residential and small to medium-size commercial customers; winter peaking system with moderate winters and cool summers; low saturation of air conditioning; relatively low marginal energy costs; fixed network, radio frequency AMR system already in place; incremental meter reading and data management costs required to support TOU and dynamic pricing options equals about $0.91/customer/month; the ratio of the CPP price to the base price equals roughly 2.17 and the ratio of the peak-period price to the base price equals 1.31.

Each rate option was evaluated on several different criteria drawn from the Standard Practice Tests for demand-side resources.[24] Our primary focus is on the total resource cost (TRC) test, which examines overall resource efficiency by comparing benefits measured as avoided energy and capacity costs with the costs of achieving them, which consist primarily of incremental metering and billing costs and investments by consumers in enabling technologies, such as programmable thermostats. Marginal energy costs used in the analysis vary by time period and utility, and range from a low of around 2¢/kWh during the economy period in the winter to a high of more than 10¢/kWh during the critical period in the summer or winter. Marginal generation capacity costs vary across utilities. The analysis for utilities A and B used a marginal generation capacity value equal to $47/kW-year whereas utility C

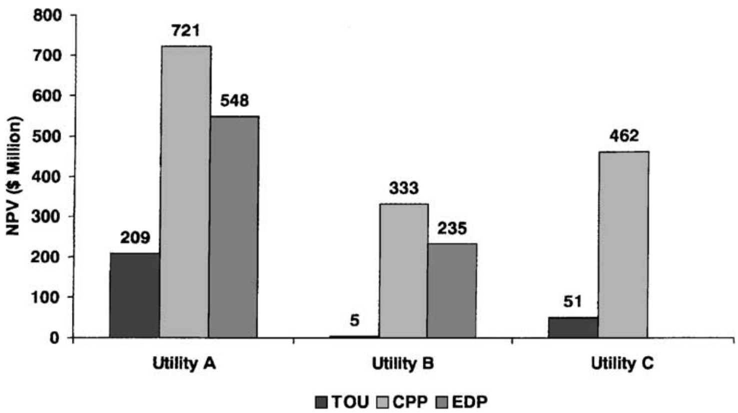


Figure 1: TRC Net Benefits for Residential Consumers

used a value of $59/kW-year. Marginal capacity costs for transmission and distribution combined equal $30/kW-year for utilities A and B and $53/kW-year for utility C.

Figure 1 shows the present value of net benefits for residential consumers.[25] The dynamic pricing options show much larger net benefits than the TOU option. Benefits for the TOU rate option are still attractive for utilities A and C, largely because these companies already have AMR systems in place and only must pay the incremental cost of obtaining TOU reads from these existing systems. Utility B, on the other hand, must install a new metering system in order to implement any of the rate options.[26] Given these higher incremental costs, the net benefits for standard TOU pricing are, at best, break-even.

Importantly, in spite of these higher incremental costs, net benefits for the dynamic pricing options for utility B are still large, equaling $333 million for the CPP rate and $235 million for EDP. Net benefit estimates for dynamic pricing for utility A, with its lower incremental costs, are extremely attractive, equaling more than $700 million for CPP and almost $550 million for the EDP rate. The results for utility C, which also has an existing AMR system, show net benefits for the CPP tariff exceeding $460 million.

Figure 2 shows the results for C&I customers for utilities B and C.[27] In aggregate, small to medium-size C&I customers follow a pattern similar to that of residential customers, with the dynamic pricing options showing much larger net benefits than standard TOU rates. However, these aggregate benefits mask important differences between small and medium C&I consumers. As seen, all rate options show marginal benefits for small C&I consumers, whereas benefits are relatively attractive for medium consumers. As indicated previously, price elasticities for C&I consumers are only about one-quarter the value for residential consumers. However, this lower responsiveness is offset by the much larger load associated with medium C&I customers. For small C&I consumers, on the other hand, low usage combined with low responsiveness means that the benefits of load shifting are insufficient to offset the incremental metering and data management costs associated with TOU or dynamic pricing.

For both residential and C&I consumers, a large share of the benefits generated by all rate alternatives examined derive from avoided capacity costs rather than avoided energy costs. The ratio of benefits associated with capacity versus energy varies with rate type, with the lowest ratios associated with TOU rates and the highest with the dynamic pricing options, where high prices at times of system peak generate significant avoided generation,

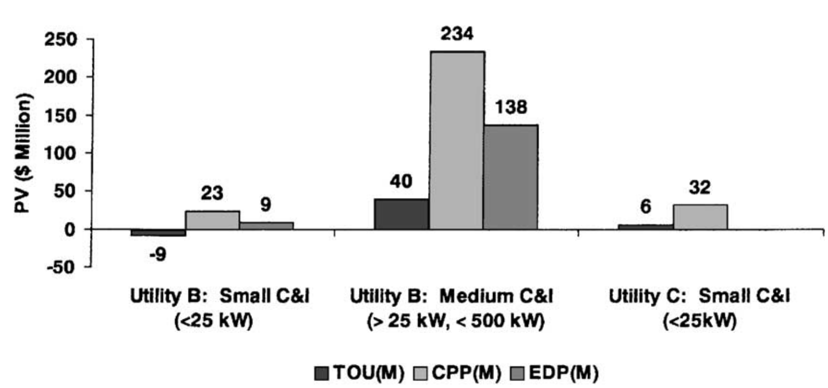


Figure 2: TRC Net Benefits for C&I Customers

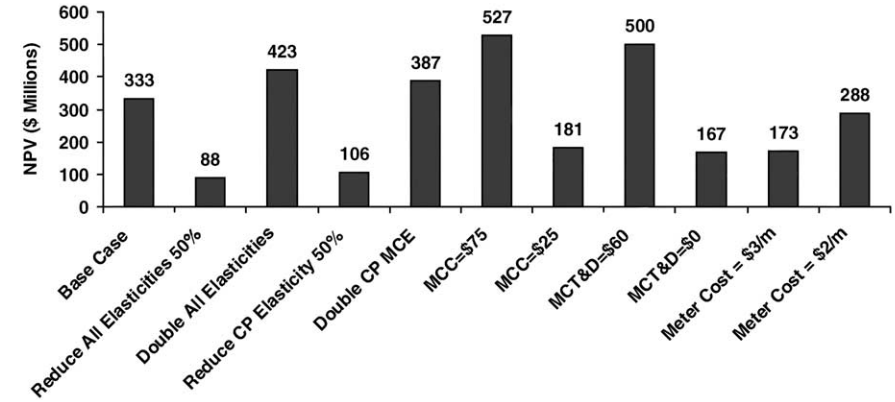


Figure 3: Residential CPP TRC Net Benefits

transmission, and distribution capacity costs.

Figure 3 shows the results of selected sensitivity tests performed on the residential market segment for the CPP rate for utility B. We present results for the residential sector because net benefit estimates are more sensitive to changes in key drivers for this segment, because of high price elasticities and the fact that total incremental metering costs are quite large relative to other segments (because of the large number of residential customers compared with C&I customers). Although the TRC test is quite sensitive to changes in key variables, net benefits remain positive across a wide range of sensitivity tests for this dynamic pricing option. Starting from a base result of \$333 million, net benefit estimates range from a low of \$88 million under the assumption that customer responsiveness is half of that assumed in the base case, to a high of \$527 million if marginal generation capacity costs are increased from \$47/kW-year to \$75/kW-year. Importantly, the net benefit estimates are still positive and reasonably attractive even when incremental metering costs are at the high end of the cost range or when marginal capacity cost values are substantially reduced. In other words, the results are robust across a wide range of assumptions.

VII. Conclusions

Dynamic pricing can provide substantial net benefits to mass-market consumers and electric utility shareholders. These benefits are substantially greater than those generated by traditional TOU rates. While net benefits are greatest when existing metering platforms are in place, they are still very attractive even when new metering must be installed. Complementary technologies combined with two-way communication can further increase impacts and make them largely painless to consumers.

However, estimates of net benefits vary significantly with the characteristics of the underlying customer base, the underlying cost curves for electricity supply, and the behavioral patterns of consumers. In other words, the results will vary from one utility to another, and are very sensitive to assumptions about price responsiveness. This has two important implications. Each utility should conduct its own estimation of net benefits based on the underlying economics of supply, usage patterns, incremental metering costs, and other key drivers. In addition, utilities should conduct well-designed, controlled experiments to accurately estimate price elasticities of demand prior to wide-scale implementation of mandatory dynamic pricing.■

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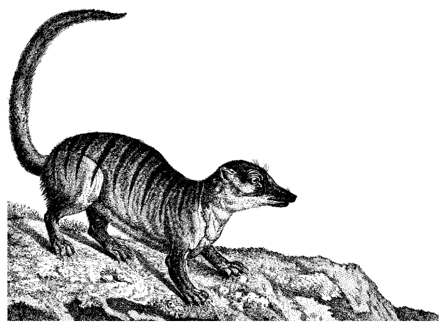

19. Massimo Filippini, *Swiss Residential Demand for Electricity by Time-of-Use: An Application of the Almost Ideal Demand System*, ENERGY J., 16 (1), 1995, at 27–39, and Massimo Filippini, *Swiss Residential Demand for Electricity by Time-of-Use*, RESOURCE ENERGY ECON., 17 (3), Nov. 1995, at 281–290.

20. See JAN PAUL ACTON AND BRIDGER M. MITCHELL, *Evaluating Time-of-Day Electricity Rates for Residential Customers*, in Bridger M. Mitchell and Paul R. Kleindorfer (eds.), REGULATED INDUSTRIES AND PUBLIC ENTERPRISE: EUROPEAN AND UNITED STATES PERSPECTIVES (Lexington, MA: Lexington Books, 1980); DENNIS J. AIGNER (ed.), *Welfare Econometrics of Peak-Load Pricing for Electricity*, J. ECONOMETRICS ANN. 3 (26), 1984; Douglas W. Caves, Joe Herriges and K. Kuester, *Load Shifting under Voluntary Residential Time-of-Use Rates*, ENERGY J., 10, 1989, at 83–99; Ahmad Faruqui, Susan S. Shaffer, Kenneth P. Seiden, Susan Blanc and John H. Chamberlin, *Customer Response to Rate Options*, EPRI Report No. CU-7131, Jan. 1991; ANDREW A. GOETT, *Can Residential Time-of-Use Rates Work? The Recent Experience*, in PROCEEDINGS: 1994 INNOVATIVE ELECTRICITY PRICING CONFERENCE, EPRI TR-103629, Feb. 1994; ANTHONY G. LAWRENCE AND DENNIS J. AIGNER (eds.), *Modeling and Forecasting Time-of-Day and Seasonal Electricity Demands*, J. ECONOMETRICS ANN. 1 (9), 1979; R.W. Parks and David Weitzel, *Measuring the Consumer Welfare Effects of Time-Differentiated Electricity Prices*, J. ECONOMETRICS ANN. 3 (26), zat 35–64.

21. This unusual design was conceived to take advantage of existing meter reading practices at selected utilities that already have automated meter reading (AMR) systems and receive daily reads. For a utility that fits this profile, which was the case for utility A, the incremental meter reading and data management costs for such a pricing option are quite low.

22. For utility A, additional analysis included examining a voluntary TOU rate with one-third market penetration, and a large-scale air conditioning direct load control program. Both options had substantially lower net benefits than the dynamic rate options. The voluntary program showed relatively small benefits while the direct load control program had benefits much smaller than the dynamic pricing options but more than twice the benefits of the mandatory TOU rate.

23. The results presented here are based on the lower cost estimate. Net benefit estimates based on the high-end cost estimate are still strongly positive for dynamic pricing options but not for the TOU rate.

24. *Economic Analysis of Demand-Side Programs: Standard Practice Manual*, Staff Report, California Public Utilities Commission and California Energy Commission, Dec. 1987. In addition to the participant test, four other tests were computed, the Utility Cost test, the Rate Impact Measure test, and the Consumers' Surplus test (which was not one of the Standard Practice Tests). The UC test measures the change in utility revenue requirements and the RIM test measures the impact on rates.

25. The results presented in Figure 1 represent net present values over 20

years for utilities A and B and 10 years for utility C.

26. Because of the need to install a new metering system and an assumption that no consumer will be placed on a new rate until all meters are installed, the cost stream for utility B starts roughly three years before the benefit stream. If regulators would allow customers to be placed on the new rates as meters are installed, the timing of the benefit and cost streams would coincide and net benefits would increase.

27. C&I consumers were not analyzed for utility A.

Simulating the Impact of TOU Pricing on Customer Usage

The assignment is to evaluate a three-part TOU rate that is spread across four time periods: a morning period, a mid-day period, an evening period, and an economy period. Customers currently face a flat rate of 7¢/kWh. Daily usage averages 680 kWh per month, of which 150 kWh are used in each of the morning, mid-day, and evening periods, and 230 kWh in the economy period. The monthly bill averages $47.60.

Based on a review of the literature, the own-price and cross-price elasticities shown below are used to predict changes in usage in each time period.

An examination of marginal costs leads suggests a three-part TOU rate design with a price of 9.45¢/kWh in the morning and evening periods, 7.35¢/kWh during the mid-day period, and 3.5¢/kWh during the evening period. On a percentage basis, the morning and evening prices have gone up by 35 percent and the mid-day price by 5 percent, while the economy price has fallen by 50 percent. The rate is revenue neutral, since the monthly bill with the new prices and old quantities would equal $47.40.

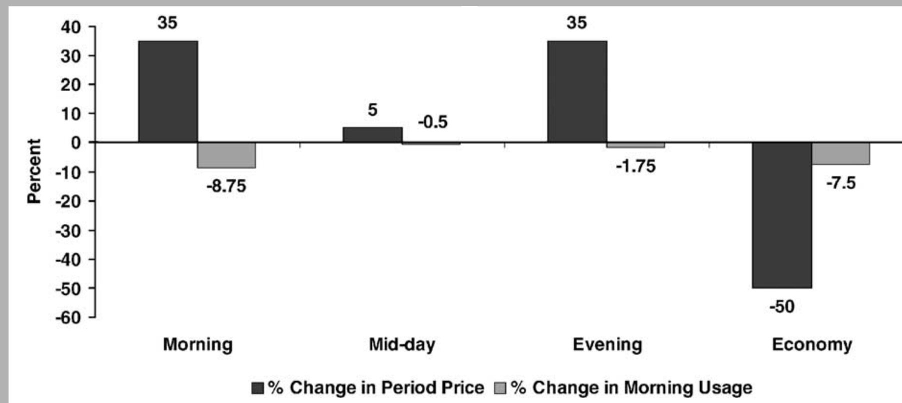

Figure 4: Change in Morning Usage Due to Change in Prices in Each Period

Figure 4 shows how the new prices will impact morning usage. The 35 percent increase in morning price will reduce it by an amount that equals the own-price elasticity of demand of −0.25 times 35 percent, or 8.75 percent. In addition, there will be several cross-price effects. Since the morning and economy periods are substitutes, the 50 percent decrease in economy price will also reduce morning usage, by 0.15 (the relevant cross-price elasticity) times 50 percent, or 7.5 percent. Since morning and mid-day are complements, the 5 percent rise in mid-day price will also reduce morning usage, by −0.10 times 5 percent, or −0.5 percent. Morning and evening usage are also complements, and the 35 percent rise in evening price will reduce morning usage by −0.05 times 35 percent, or −1.75 percent. Adding up all of these own and cross-price effects, we get a total change in morning usage of −18.5 percent. This is graphed in Figure 4. Similar calculations can be used to estimate the change in usage in all pricing periods. When this analysis is performed, we find that mid-day usage decreases 9 percent, evening usage decreases 13.3 percent, and economy usage rises 18.3 percent. Daily usage falls by 2.8 percent, and the new bill is $43.40.

Elasticity Matrix	Morn	Mid	Eve	Econ
Morn	−0.25	−0.10	−0.05	0.15
Mid	−0.10	−0.25	−0.05	0.05
Eve	−0.10	−0.05	−0.20	0.05
Econ	0.15	0.05	0.15	−0.15