Dynamic Pricing: A Framing Document

Kansas Corporation Commission
Workshop on Energy Efficiency
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Objectives of Dynamic Pricing:
- Signal to customers the times of the day, week, season and year when electric power production costs are higher or lower than average, and influence customers' choices to consume electricity based on that information.
- Promote energy efficiency and demand response investments by customers intended to avoid consumption at times when production costs tend to be higher.
- Convey to consumers consistency between energy efficiency programs and pricing policy.
- Avoid a backlash of resistance to unfamiliar pricing, confusing equipment at the customers' premises and unintended bill impacts.

Background Documents Included Here:
National Action Plan for Energy Efficiency Report, July 2006, Chapter 5 [1]
Ahmad Faruqui, "Pricing Programs: Time of Use and Real Time"[2]

About Dynamic Pricing
"Dynamic" refers to the changing with time of the price for electricity that consumers pay, as distinguished from "static" or flat rate pricing. Dynamic pricing done properly promotes the regulatory principle of cost causation. The more extreme the form of dynamic pricing, the better the alignment of rates to the cost customers impose. There are many options for dynamic pricing reform:
- The most extreme is real time pricing, in which the price changes throughout the day, usually hourly. Larger customers in many states experience real time prices.
- Less extreme is critical peak pricing, which is usually a time of use rate structure with a very high rate that is charged during a small percentage (generally 1%) of the hours in a year (these hours are only known a short time in advance, either the day before or even that day, but with enough time for the customer to avoid usage at the critical peak hours). There are many variants; however, a key element to most is the multiple between the critical peak rate and the average rate, which must be high enough to prompt a customer response.[3] A variant now being piloted offers customers a rebate if their electric use falls below a baseline during peak hours.
- Less extreme still is a time of use price structure with sufficient differential between on-peak and off-peak times to affect customer usage.

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[1] http://www.epa.gov/cleanenergy/energy-programs/napee/resources/action-plan.html (March 15, 2008)
[2] Faruqui, Ahmad (2007) 'Pricing Programs: Time-of-Use and Real Time, Encyclopedia of Energy Engineering and Technology, 1:1, 1175 - 1183
[3] Patty Harper-Slobozowicz of Utilipoint suggests the multiple must be at least three to get the desired peak effects. Some pilots have included a multiple of 5 or 7 or more.

- Further rate design enhancements that promote value and efficiency are: seasonal differential structures can signal the seasons when peak use tends to occur; an inclining block rate can favor low volume users, while charging higher rates for usage above a threshold each month.

Key considerations

Simplicity:

Customers have been found to understand and optimize their usage with rate designs that are somewhat more complex that one rate all the time. Yet, care must be taken to avoid such complexity that the customer loses interest in responding and perhaps gets upset. For example, an inclining block structure that has two, or maybe three usage steps can work, but more steps confound the customer. The notification of the critical peak hours must be clear and with sufficient notice.

Education:

While customers may be prone to inertia concerning their utility rates, education about the change and the new system is important. Education can enable customers to understand more clearly what they can change about their consumption to take the greatest advantage of the new system. Education can also head off a backlash from customers who might object to the change for whatever reason.

What will the default rate be?:

Interested customers can get experience by opting in to dynamic prices. With this approach, most consumers can continue with the rates they are used to. On the other hand, system benefits in the form of peak reductions associated with dynamic pricing will be modest. A more aggressive approach is to use a dynamic price structure, perhaps a critical peak structure, as the default rate. Customers uneasy about service under a critical peak structure may be given the opportunity to opt out to a flat rate.

Research suggests that customers tend to keep the rate they are given. Dynamic pricing advocates point to these results and say that customers will accept dynamic prices, especially if suitable consumer education lays a foundation. Others are not convinced, suggesting that consumers do not want more information to manage about their electric service in the midst of already complex lives.

Supporting and Enabling Hardware and Technology:

Conventional meters accumulate a record of usage over time but there is no distinction indicating when the usage occurred. A conventional meter can be modified with a data recording system such that the usage in a given hour can be recorded and matched after the fact with the price prevailing at the time. Under this approach with a real time price or with a critical peak price, the consumer gets no signal that might affect usage, so a key advantage of these pricing plans is lost under this set up. A conventional meter with hourly usage recording can support a time of use rate, since consumers can know the rate being charged at any given time. If consumers know that rates are high during a July afternoon, they can buy efficient appliances that tend to run at these hours, and develop a habit to curtail use of non-essential appliances and equipment.

Advanced metering infrastructure (AMI) refers to a system that includes meters with one way or two way communications, as well as the data management system and other systems at the load serving entity that make the most of the new meters. This system would support any pricing system, including prices that can change a dozen times in each hour, and has the key attribute of signaling to customers when prices will or will likely change up or down. This system also has the potential to automatically control customer appliances and equipment, adjusting thermostats and light levels, or cycling off pool pumps and refrigeration systems with pre-programmed logic controlled by the customer. Thus, AMI enables demand response programs to be available to anyone with a controllable end use, no matter how small. AMI also enables many beneficial system features, including precise outage detection and diagnosis of the state of the system, instant service connections and disconnections, customized customer baselines to more accurately value efficiency and demand response

An important side note to the topic of advanced metering infrastructure is cost. Conversion comes in two levels. If dynamic pricing and AMI are voluntary (customers opt in), the costs can be modest overall, though they might be high per customer. Importantly, system benefits would be lost since AMI would be scattered somewhat randomly throughout the system. If dynamic pricing and AMI are the default (customers may opt out) or are mandatory, then hardware deployment will be system wide over a period of a few years at cost of perhaps $200-$300 per customer. A few state commissions are in the process of considering utility proposals to deploy AMI system wide and many more are evaluating the results of AMI pilots.

<u>Winners and Losers</u>:

Managing winners and losers is perhaps the hardest aspect of a transition from flat retail rates and is familiar, though uncomfortable ground for utility regulators. Any change in rate design resulting in charging more during peak hours will disfavor those customers who tend to use a lot of electricity at peak hours. Explaining that these customers have been getting the benefit of high cost electricity at average prices does not always work.

An important way through this transition is to remember that these changes should result in lower use at high cost times, more efficient use over all and real dollar savings. The challenge, then, is to enable the “winners” to benefit from system savings, while minimizing the cost impact to the “losers.”

<u>Is there a risk premium in the utility cost of service that serves to manage utility risk of uncertain costs that cannot be passed through to customers due to flat retail rates?</u>:

An additional source of savings is available, though one would not find it explicitly in a utility rate case cost of service, if the utility with flat rates faces the challenge of procuring power in a marketplace relying on commodity fuels and other cost uncertainties, unable to pass unanticipated savings and costs to customers. The utility is managing these risks. If the utility is now able to pass some of the costs of high priced power to customers in the form of higher rates at peak, some of the traditional risk management measures employed by utilities should become unnecessary.

Reasonable expectations:

Rates more aligned with costs will help customers change their behavior. Economists can measure the elasticity of electric consumption. Peak demand will be reduced, especially if dynamic pricing is coupled with aggressive demand response programs, and this will slow the need for new electric capacity.

Some usage will shift from high priced hours to low priced hours, while some usage is eliminated, or made permanently more efficient. This consideration is important if a state is preparing for greenhouse gas mitigation, in which consumption reductions are important. In isolation, dynamic prices have a modest effect on reducing consumption compared with energy efficiency programs. ACEEE suggests the effect of programs compared with prices is 10 to 1. Dynamic pricing coupled with aggressive energy efficiency programs and aggressive demand response programs send the most effective signals to customers about current and future electric markets.

Lessons Learned and Best Practices

- The chapter by Ahmad Faruqui, attached, contains several useful conclusions on lessons learned and best practices in dynamic pricing.

- There is significant experience across the U.S. with dynamic prices for larger customers. There is limited experience outside of recent pilots for mass market customers. States can learn from this experience and bypass pilots, but many state commissions and utilities appear to need to experience a dynamic price pilot before gaining sufficient confidence to make a utility-wide commitment.

- The California utilities are making significant progress in dynamic pricing, in linking them to energy efficiency and in investigating the merits of enabling hardware and technology and offer perhaps the most comprehensive set of experiences for others to evaluate.

- An important action a state can take is to consider eliminating any existing rate design that actively encourages the consumption of energy, such as declining block rates.

- Experience does tell us that a hasty or poorly planned transition can lose the confidence and support of consumers and do long lasting harm to the reputation of dynamic pricing.

5: Rate Design

Retail electricity and natural gas utility rate structures and price levels influence customer consumption, and thus are an important tool for encouraging the adoption of energy-efficient technologies and practices. The rate design process typically involves balancing multiple objectives, among which energy efficiency is often overlooked. Successful rate designs must balance the overall design goals of utilities, customers, regulators, and other stakeholders, including encouraging energy efficiency.

Overview

Retail rate designs with clear and meaningful price signals, coupled with good customer education, can be powerful tools for encouraging energy efficiency. At the same time, rate design is a complex process that must take into account multiple objectives (Bonbright, 1961; Philips, 1988). The main priorities for rate design are recovery of utility revenue requirements and fair apportionment of costs among customers.

Other important regulatory and legislative goals include:

- Stable revenues for the utility.
- Stable rates for customers.
- Social equity in the form of lifeline rates for essential needs of households (PURPA of 1978).
- Simplicity of understanding for customers and ease of implementation for utilities.
- Economic efficiency to promote cost-effective load management.

This chapter considers the additional goal of encouraging investment in energy efficiency. While it is difficult to achieve every goal of rate design completely, consideration of a rate design's impact on adoption of energy efficiency and any necessary trade-offs can be included as part of the ratemaking process.

Using Rate Design to Promote Energy Efficiency

In developing tariffs to encourage energy efficiency, the following questions arise: (1) What are the key rate design issues, and how do they affect rate designs for energy efficiency? (2) What different rate design options are possible, and what are their pros and cons? (3) What other mechanisms can encourage efficiency that are not driven by tariff savings? and (4) What are the most successful strategies for encouraging energy efficiency in different jurisdictions? These questions are addressed throughout this chapter.

Leadership Group Recommendations Applicable to Rate Design

- Modify ratemaking practices to promote energy efficiency investments.
- Broadly communicate the benefits of, and opportunities for, energy efficiency.

A more detailed list of options specific to the objective of promoting energy efficiency in rate design is provided at the end of this chapter.

Background: Revenues and Rates

Utility rates are designed to collect a specific revenue requirement based on natural gas or electricity sales. As rates are driven by sales and revenue requirements, these three aspects of regulation are tightly linked. (Revenue requirement issues are discussed in Chapter 2: Utility Ratemaking & Revenue Requirements.)

Until the 1970s, rate structures were based on the principle of average-cost pricing in which customer prices reflected the average costs to utilities of serving their customer class. Because so many of a utility's costs were fixed, the main goal of rate design up until the 1970s was to promote sales. Higher sales allowed fixed costs to be spread over a larger base and helped push rates down, keeping stakeholders content with average-cost based rates (Hyman et al., 2000).

This dynamic began to change in many jurisdictions in the 1970s, with rising oil prices and increased emphasis on conservation. With the passage of the 1978 Public Utility Regulatory Policies Act (PURPA), declining block rates were replaced by flat rates or even inverted block rates, as utilities began to look for ways to defer new plant investment and reduce the environmental impact of energy consumption.

Key Rate Design Issues

Utilities and regulators must balance competing goals in designing rates. Achieving this balance is essential for obtaining regulatory and customer acceptance. The main rate design issues are described below.

Provide Recovery of Revenue Requirements and Stable Utility Revenues

A primary function of rates is to let utilities collect their revenue requirements. Utilities often favor rate forms that maximize stable revenues, such as declining block rates. The declining block rate has two or more tiers of usage, with the highest rates in the first tier. Tier 1 is typically a relatively low monthly usage level that most customers exceed. This rate gives utilities a high degree of certainty regarding the number of kilowatt-hours (kWh) or therms that will be billed in Tier 1. By designing Tier 1 rates to collect the utility's fixed costs, the utility gains stability in the collection of those costs. At the same time, the lower Tier 2 rates encourage higher energy consumption rather than efficiency, which is detrimental to energy efficiency impacts.[1] Because energy efficiency measures are most likely to change customer usage in Tier 2, customers will see smaller bill reductions under declining block rates than under flat rates. Although many utilities have phased out declining block rates, a number of utilities continue to offer them.[2]

Another rate element that provides revenue stability but also detracts from the incentive to improve efficiency is collecting a portion of the revenue requirement through a customer charge that is independent of usage. Because the majority of utility costs do not vary with changes in customer usage level in the short run, the customer charge also has a strong theoretical basis. This approach has mixed benefits for energy efficiency. On one hand, a larger customer charge means a smaller volumetric charge (per kWh or therm), which lowers the customer incentive for energy efficiency. On the other hand, a larger customer charge and lower volumetric charge reduces the utilities profit from increased sales, reducing the utility disincentive to promote energy efficiency.

Rate forms like declining block rates and customer charges promote revenue stability for the utility, but they create a barrier to customer adoption of energy efficiency because they reduce the savings that customers can realize from reducing usage. In turn, electricity demand is more likely to increase, which could lead to long-term higher rates and bills where new supply is more costly than energy efficiency. To promote energy efficiency, a key challenge is to provide a

[1] Brown and Sibley (1986) opine that a declining block structure can promote economic efficiency if the lowest tier rate can be set above marginal cost, while inducing additional consumption by some consumers. A rising marginal cost environment suggests, however, that a declining block rate structure with rates below the increasing marginal costs is economically inefficient.

[2] A partial list of utilities with declining block residential rates includes: Dominion Virginia Power, VA; Appalachian Power Co, VA; Indianapolis Power and Light Co., IN; Kentucky Power Co., KY; Cleveland Electric Illum Co., OH; Toledo Edison Co., OH; Rappahannock Electric Coop, VA; Lincoln Electric System, NE; Cuivre River Electric Coop Inc., MO; Otter Tail Power Co., ND; Wheeling Power Co., WV; Matanuska Electric Assn Inc., AK; Homer Electric Association Inc., AK; Lower Valley Energy, NE.

level of certainty to utilities for revenue collection without dampening customer incentive to use energy more efficiently.

Fairly Apportion Costs Among Customers

Revenue allocation is the process that determines the share of the utility's total revenue requirement that will be recovered from each customer class. In regulatory proceedings, this process is often contentious, as each customer class seeks to pay less. This process makes it difficult for utilities to propose rate designs that shift revenues between different customer classes.

In redesigning rates to encourage energy efficiency, it is important to avoid unnecessarily or inadvertently shifting costs between customer classes. Rate design changes should instead focus on providing a good price signal for customer consumption decisions.

Promote Economic Efficiency for Cost-Effective Load Management

According to economic theory, the most efficient outcome occurs when prices are equal to marginal costs, resulting in the maximum societal net benefit from consumption.

Marginal Costs

Marginal costs are the *changes* in costs required to produce one additional unit of energy. In a period of rising marginal costs, rates based on marginal costs more realistically reflect the cost of serving different customers, and provide an incentive for more efficient use of resources (Bonbright, 1961; Kahn, 1970; Huntington, 1975; Joskow, 1976; Joskow, 1979).

A utility's marginal costs often include its costs of complying with local, state, and federal regulations (e.g., Clean Air Act), as well as any utility commission policies addressing the environment (e.g., the use of the societal test for benefit-cost assessments). Rate design based on the utility's marginal costs that promotes cost-effective energy efficiency will further increase environmental protection by reducing energy consumption.

Despite its theoretical attraction, there are significant barriers to fully implementing marginal-cost pricing in electricity, especially at the retail level. In contrast to other commodities, the necessity for generation to match load at all times means that outputs and production costs are constantly changing, and conveying these costs as real time "price signals" to customers, especially residential customers, can be complicated and add additional costs. Currently, about half of the nation's electricity customers are served by organized real-time electricity markets, which can help provide time-varying prices to customers by regional or local area.

Notwithstanding the recent price volatility, exacerbated by the 2005 hurricane season and current market conditions, wholesale natural gas prices are generally more stable than wholesale electricity prices, largely because of the ability to store natural gas. As a result, marginal costs have been historically a less important issue for natural gas pricing.

Short-Run Versus Long-Run Price Signals

There is a fundamental conflict between whether electricity and natural gas prices should reflect short-run or long-run marginal costs. In simple terms, short-run costs reflect the variable cost of production and delivery, while long-run costs also include the cost of capital expansion. For programs such as real-time pricing in electricity, short-run marginal costs are used for the price signals so they can induce efficient operating decisions on a daily or hourly basis.

Rates that reflect long-run marginal costs will promote economically efficient investment decisions in energy efficiency, because the long-run perspective is consistent with the long expected useful lives of most energy efficiency measures, and the potential for energy efficiency to defer costly capital investments. For demand-response and other programs intended to alter consumption on a daily or hourly basis, however, rates based on short-run

Applicability of Rate Design Issues

Implications for Clean Distributed Generation and Demand Response. The rate issues for energy efficiency also apply to clean distributed generation and demand response, with two exceptions. Demand response is focused on reductions in usage that occur for only a limited number of hours in a year, and occur at times that are not known far in advance (typically no more than one day notice, and often no more than a few hours notice). Because of the limited hours of operation, the revenue erosion from demand response is small compared to an energy efficiency measure. In addition, it could be argued that short-run, rather than long-run, costs are the appropriate cost metric to use in valuing and pricing demand response programs.

Public Versus Private Utilities. The rate issues are essentially the same for both public and private utilities. Revenue stability might be a lesser concern for public utilities, as they could approach their city leaders for rate changes. Frequent visits to council chambers for rate changes might be frowned upon, however, so revenue stability will likely remain important to many public utilities as well.

Gas Versus Electric. As discussed above, gas marginal costs are less volatile than electricity marginal costs, so providing prices that reflect marginal costs is generally less of a concern for the gas utilities. In addition, the nature of gas service does not lend itself to complicated rate forms such as those seen for some electricity customers. Nevertheless, gas utilities could implement increasing tier block rates, and/or seasonally differentiated rates to stimulate energy efficiency.

Restructured Versus Non-Restructured Markets. Restructuring has had a substantial impact on the funding, administration, and valuation of energy efficiency programs. It is no coincidence that areas with high retail electricity rates have been more apt to restructure their electricity markets. The higher rates increase the appeal of energy efficiency measures, and the entry of third-party energy service companies can increase customer interest and education regarding energy efficiency options. In a retail competition environment, however, there might be relatively little ratemaking flexibility. In several states, restructuring has created transmission and distribution-only utilities, so the regulator's ability to affect full electricity rates might be limited to distribution costs and rates for default service customers.

marginal cost might be more appropriate. Therefore, in developing retail rates, the goals of short-run and long-run marginal based pricing must be balanced.

Cost Causation

Using long-run marginal costs to design an energy-efficiency enhancing tariff can present another challenge —potential inconsistency with the cost-causation principle that a tariff should reflect the utility's various costs of serving a customer. This potential inconsistency diminishes in the long run, however, because over the long run, some costs that might be considered fixed in the near term (e.g., generation or transmission capacity, new interstate pipeline capacity or storage) are actually variable. Such costs can be reduced through sustained load reductions provided by energy efficiency investment, induced by appropriately designed marginal cost-based rates. Some costs of a utility do not vary with a customer's kWh usage (e.g., hookup and local distribution). As a result, a marginal cost-based rate design may necessarily include some fixed costs, which can be collected via a volumetric adder or a relatively small customer charge. However, utilities that set usage rates near long-run marginal costs will encourage energy efficiency and promote other social policy goals such as affordability for low-income and low-use customers whose bills might increase with larger, fixed charges. Hence, a practical implementation of marginal-cost based ratemaking should balance the trade-offs and competing goals of rate design.

Provide Stable Rates and Protect Low-Income Customers

Rate designs to promote energy efficiency must consider whether or not the change will lead to bill increases. Mitigating large bill increases for individual customers is a fundamental goal of rate design, and in some jurisdictions low-income customers are also afforded particular attention to ensure that they are not adversely affected by rate changes. In some cases, low-income customers are eligible for special rates or rate riders that protect them from large rate increases, as exemplified by the lifeline rates provision in Section 114 of the 1978 PURPA. Strategies to manage bill impacts include phasing-in rate changes to reduce the rate shock in any single year, creating exemptions for certain at-risk customer groups, and disaggregating customers into small customer groups to allow more targeted rate forms.

Because of the concern over bill impacts, new and innovative rates are often offered as voluntary rates. While improving acceptance, voluntary rate structures generally attract a relatively small percentage of customers (less than 20 percent) unless marketed heavily by the utility. Voluntary rates can lead to some "free riders," meaning customers who achieve bill reductions without changing their consumption behavior and providing any real savings to the utility. Rates to promote energy efficiency can be offered as voluntary, but the low participation and free rider issues should be taken into account in their design to ensure that the benefits of the consumption changes they encourage are at least as great as the resulting bill decreases.

Maintain Rate Simplicity

Economists and public policy analysts can become enamored with efficient pricing schemes, but customers generally prefer simple rate forms. The challenge for promoting energy efficiency is balancing the desire for rates that provide the right signals to customers with the need to have rates that customers can understand, and to which they can respond. Rate designs that are too complicated for customers to understand will not be effective at promoting efficient consumption decisions. Particularly in the residential sector, customers might pay more attention to the total bill than to the underlying rate design.

Addressing the Issues: Alternative Approaches

The prior sections listed the issues that stakeholders must balance in designing new rates. This section presents some traditional and non-traditional rate designs and discusses their merits for promoting energy efficiency. The alternatives described below vary by metering/billing requirement, information complexity, and ability to reflect marginal cost.[3]

Rate Design Options

Inclining Tier Block

Inclining tier block rates, also referred to as inverted block rates, have per-unit prices that increase for each successive block of energy consumed. Inclining tiered rates offer the advantages of being simple to understand and simple to meter and bill. Inclining rates can also meet the policy goal of protecting small users, which often include low-income customers. In fact, it was the desire to protect small users that prompted the initiation of increasing tiers in California. Termed "lifeline rates" at the time, the intention was to provide a small base level of electricity to all residential customers at a low rate, and charge the higher rate only to usage above that base level. The concept of lifeline rates continues in various forms for numerous services such as water and sewer services, and can be considered for delivery or commodity rates for electricity and natural gas. However, in many parts of the country, low-income customers are not necessarily low-usage customers, so a lifeline rate might not protect all low-income customers from energy bills.

[3] As part of its business model, a utility may use innovative rate options for the purpose of product differentiation. For example, advanced metering that enables a design with continuously time-varying rates can apply to an end-use (e.g., air conditioning) that is the main contributor to the utility's system peak. Another example is the bundling of sale of electricity and consumer devices (e.g., a 10-year contract for a central air conditioner whose price includes operation cost).

Tiered rates also provide a good fit for regions where the long-run marginal cost of energy exceeds the current average cost of energy. For example, regions with extensive hydroelectric resources might have low average costs, but their marginal cost might be set by much higher fossil plant costs or market prices (for purchase or export).

See Table 5-1 for additional utilities that offer inclining tier residential rates.

Time of Use (TOU)

TOU rates establish varying charges by season or time of day. Their designs can range from simple on- and off-peak rates that are constant year-round to more complicated rates with seasonally differentiated prices for several time-of-day periods (e.g., on-, mid- and off-peak). TOU rates have support from many utilities because of the flexibility to reflect marginal costs by time of delivery.

TOU rates are commonly offered as voluntary rates for residential electric customers,[4] and as mandatory rates for larger commercial and industrial customers. Part of the reason for TOU rates being applied primarily to larger users is the additional cost of TOU metering and billing, as well as the assumed greater ability of larger customers to shift their loads.

TOU rates are less applicable to gas rates, because the natural storage capability of gas mains allows gas utilities to procure supplies on a daily, rather than hourly, basis. Additionally, seasonal variations are captured to a large extent in costs for gas procurement, which are typically passed through to the customer. An area with constrained seasonal gas transportation capacity, however, could merit a higher distribution cost during the constrained season. Alternatively, a utility could recover a higher share of its fixed costs during the high demand season, because seasonal peak demand drives the sizing of the mains.

As TOU rates are typically designed to be revenue-neutral with the status quo rates, a high on-peak price will be accompanied by a low off-peak price. Numerous studies in electricity have shown that while the high on-peak prices do cause a reduction in usage during that period, the low off-peak prices lead to an increase in usage in the low-cost period. There has also been an

Table 5-1. Partial List of Utilities With Inclining Tier Residential Rates

Utility Name	State	Tariff URL
Florida Power and Light	FL	http://www.fpl.com/access/contents/how_to_read_your_bill.shtml
Consolidated Edison	NY	http://www.coned.com/documents/elec/201-210.pdf
Pacific Gas & Electric	CA	http://www.pge.com/res/financial_assistance/medical_baseline_life_support/understanding/index.html#topic4
Southern California Edison	CA	http://www.sce.com/NR/rdonlyres/728FFC8C-91FD-4917-909B-
Arizona Public Service Co	AZ	https://www.aps.com/my_account/RateComparer.html
Sacramento Municipal Util Dist	CA	http://www.smud.org/residential/rates.html
Indiana Michigan Power Co	MI	https://www.indianamichiganpower.com/global/utilities/tariffs/Michigan/MISTD1-31-06.pdf
Modesto Irrigation District	CA	http://www.mid.org/services/tariffs/rates/ums-d-residential.pdf
Turlock Irrigation District	CA	http://www.tid.org/Publisher_PDFs/DE.pdf
Granite State Electric Co	NH	http://www.nationalgridus.com/granitestate/home/rates/4_d.asp
Vermont Electric Cooperative, Inc	VT	http://www.vtcoop.com/PageViewer.aspx?PageName=Rates%20Summary
City of Boulder	NV	http://www.bcnv.org/utilities.html#electric,waterandsewer

[4] For a survey of optional rates with voluntary participation, see Horowitz and Woo (2006).

"income effect" observed where people buy more energy as their overall bill goes down, due to switching consumption to lower price periods. The net effect might not be a significant decrease in total electricity usage, but TOU rates do encourage reduced usage when that reduction is the most valuable. Another important consideration with TOU prices is the environmental impact. Depending on generation mix and the diurnal emissions profile of the region, shifting consumption from the on-peak period to off-peak period might provide environmental net benefits.

The Energy Policy Act of 2005 Section 1252 requires states and non-regulated utilities, by August 8, 2007, to consider adopting a standard requiring electric utilities to offer all of their customers a time-based rate schedule such as time-of-use pricing, critical peak pricing, real-time pricing, or peak load reduction credits.

Dynamic Rates

Under a dynamic rate structure, the utility has the ability to change the cost or availability of power with limited, or no, notice. Common forms of dynamic rates include the following:

- Real-time pricing (RTP) rates vary continuously over time in a way that directly reflects the wholesale price of electricity.

- Critical peak pricing (CPP) rates have higher rates during periods designated as critical peak periods by the utility. Unlike TOU blocks, the days in which critical peaks occur are not designated in the tariff, but are designated on relatively short notice for a limited number of days during the year.

- Non-firm rates typically follow the pricing form of the otherwise applicable rates, but offer discounts or incentive payments for customers to curtail usage during times of system need (Horowitz and Woo, 2006). Such periods of system need are not designated in advance through the tariff, and the customer might receive little notice before energy supply is interrupted. In some cases, customers may be allowed to "buy through" periods when their supply will be interrupted by paying a higher energy charge (a non-compliance penalty). In those cases, the non-firm rate becomes functionally identical to CPP rates.

Dynamic rates are generally used to: 1) promote load shifting by large, sophisticated users, 2) give large users access to low "surplus energy" prices, or 3) reduce peak loads on the utility system. Therefore, dynamic rates are complementary to energy efficiency, but are more useful for achieving demand response during peak periods than reducing overall energy usage.

Two-Part Rates

Two-part rates refer to designs wherein a base level of customer usage is priced at rates similar to the status quo (Part 1) and deviations from the base level of usage are billed at the alternative rates (Part 2). Two-part rates are common among RTP programs to minimize the free rider problem. By implementing a two-part rate, customers receive the real time price only for their change in usage relative to their base level of usage. Without the two-part rate form, most low load-factor customers on rates with demand charges would see large bill reductions for moving to an RTP rate.

A two-part rate form, however, could also be combined with other rate forms that are more conducive to energy efficiency program adoption. For example, a two-part rate could be structured like an increasing tiered block rate, with the Tier 1 allowance based on the customer's historical usage. This structure would address many of the rate design barriers such as revenue stability. Of course, there would be implementation issues, such as determining what historical period is used to set Part 1, and how often that baseline is updated to reflect changes in usage. Also, new customers would need to be assigned an interim baseline.

Demand Charges

Demand charges bill customers based on their peak usage rather than their total usage during the month. For electricity, demand charges are based on usage during particular TOU periods (e.g., peak demand) or usage during any period in the month (e.g., maximum demand). Demand charges can also use a percentage of the highest demand over the prior year or prior season as a minimum demand level used for billing. For natural gas, demand can be based on the highest monthly usage over the past year or season.

For both gas and electricity, utilities prefer demand charges over volumetric charges because they provide greater revenue certainty, and encourage more consistent asset utilization. In contrast to a demand charge, a customer charge that covers more of a utility's fixed costs reduces profits from increased sales, and the utility disincentive to promote energy efficiency.

For energy efficiency programs, demand charges could help promote reductions in usage for those end uses that cause the customer's peak.[5] In general, however, volumetric rates are more favorable for energy efficiency promotion. Increasing the demand charges would reduce the magnitude of the price signal that could be sent through a volumetric charge.

Mechanisms Where Customer Benefits Are Not Driven by Tariff Savings

The rate design forms discussed above allow customers to benefit from energy efficiency through bill reductions; however, other types of programs provide incentives that are decoupled from the customer's retail rate.

Discount for Efficiency via Conservation Behavior

In some cases, energy efficiency benefits are passed on to customers through mechanisms other than retail rates. For example, in California the "20/20" program was implemented in 2001, giving customers a 20 percent rebate off their summer bills if they could reduce their electricity consumption by 20 percent compared to the summer period the prior year. The program's success was likely due to a combination of aggressive customer education, energy conservation behavior (reducing consumption through limiting usage of appliances and end-uses) and investment in energy efficiency. Pacific Gas & Electric (PG&E) has just implemented a similar program for natural gas, wherein customers can receive a rebate of 20 percent of their last winter's bill if they can reduce natural gas usage by 10 percent this winter season. The 20/20 program was popular and effective. It was easy for customers to understand, and there might be a psychological advantage to a program that gives you a rebate (a received reward), as opposed to one that just allows you to pay less than you otherwise would have (a lessened penalty). Applying this concept might require some adjustments to account for changes in weather or other factors.

Benefit Sharing

There are two types of benefit sharing with customers.[6] Under the first type of shared savings, a developer (utility or third party) installs an energy-saving device. The customer shares the bill savings with the developer until the customer's project load has been paid off. In the second type of shared savings, the utility is typically the developer and installs an energy efficiency or distributed generation device at the customer site. The customer then pays an amount comparable to what the bill would have been without the device or measures installed, less a portion of the savings of the device based on utility avoided costs. This approach decouples the customer benefits from the utility rate, but it can be complicated to determine what the consumption would have been without the device or energy efficiency.

PacifiCorp in Oregon tackled this problem by offering a cash payment of 35 percent of the cost savings for residential weatherization measures, where the cost savings was based on the measure's expected annual kWh savings and a schedule of lifecycle savings per kWh (PacifiCorp, 2002).

[5] Horowitz and Woo (2006) show that demand charges can be used to differentiate service reliability, thus implementing curtailable and interruptible service programs that are useful for meeting system resource adequacy.

[6] Note that benefit sharing is not the same as "shared savings," used in the context of utility incentives for promoting energy efficiency programs.

Table 5-2. Pros and Cons of Rate Design Forms

Program Type	Criteria				
	Avoided Cost Benefits and Utility Incentives	Energy and Peak Reductions	Customer Incentive and Bill Impact	Impact on Non-Participants	Implementation and Transition Issues
Increasing Tier Block (Inverted block) http://www.pge.com/tariffs/pdf/E-1.pdf http://www.sdge.com/tm2/pdf/DR.pdf http://www.sdge.com/tm2/pdf/GR.pdf	**Pro:** Good match when long-run marginal costs are above average costs. **Con:** Might not be the right price signal if long-run marginal costs are below average costs.	**Pro:** Can achieve annual energy reductions. **Con:** Does not encourage reductions in any particular period (unless combined with a time-based rate like TOU).	**Pro:** Provides strong incentive to reduce usage. **Con:** Could result in large bill increases for users that cannot change their usage level, and could encourage more usage by the smaller customers.	**Pro:** If mandatory, little impact on other customer classes. **Con:** Could not be implemented on a voluntary basis because of free rider losses.	**Pro:** Simple to bill with existing meters. **Con:** Could require phased transition to mitigate bill impacts.
Time of Use (TOU) http://www.nationalgridus.com/masselectric/home/rates/4_tou.asp	**Pro:** (1) Low implementation cost; (2) Tracks expected marginal costs. **Con:** Unclear if marginal costs should be short- or long-run.	**Pro:** Can achieve peak load relief. **Con:** Might not achieve substantial energy reductions or produce significant emissions benefits.	**Pro:** Provides customers with more control over their bills than flat rates, and incentive to reduce peak usage. **Con:** If mandatory, could result in large bill increases for users that cannot change their usage pattern.	**Pro:** If mandatory, little average impact, but can be large on some customers. **Con:** If optional, potentially large impact due to free riders, which can be mitigated by a careful design.	**Pro:** Extensive industry experience with TOU rate. **Con:** (1) If mandatory, likely opposed by customers, but not necessarily the utility; (2) If optional, opposed by non-participants and possibly the utility.
Dynamic Rates: Real Time Pricing (RTP) http://www.exeloncorp.com/comed/library/pdfs/advance_copy_tariff_revision6.pdf http://www.southerncompany.com/gulfpower/pricing/gulf_rates.asp?mnuOpco=gulf&mnuType=com&mnuItem=er#rates http://www.nationalgridus.com/niagaramohawk/non_html/rates_psc207.pdf	**Pro:** (1) Tracks day-ahead or day-of short-run marginal cost for economically efficient daily consumption decisions; (2) RTP rates can be set to help allocate capacity in an economically efficient manner during emergencies. **Con:** No long-run price signal for investment decisions.	**Pro:** Can achieve peak load relief. **Con:** (1) Not applicable to gas; (2) Might not achieve substantial annual energy reductions or produce significant emissions benefits.	Same as above.	Same as above.	**Con:** (1) If mandatory, likely opposed by customers and the utility due to complexity and implementation cost; (2) High implementation cost for metering and information system costs.
Dynamic Rates: Critical Peak Pricing (CPP) http://www.southerncompany.com/gulfpower/pricing/pdf/rsvp.pdf http://www.idahopower.com/aboutus/regulatoryinfo/tariffPdf.asp?id=263&.pdf http://www.pge.com/tariffs/pdf/E-3.pdf	**Pro:** (1) Tracks short-run marginal cost shortly before emergency; (2) If the CPP rates are set at correctly predicted marginal cost during emergency, they ration capacity efficiently. **Con:** High implementation cost.	**Pro:** Likely to achieve load relief. **Con:** Unlikely to provide significant annual energy reductions.	Same as above.	**Pro:** Little impact, unless the utility heavily discounts the rate for the non-critical hours.	**Con:** (1) If mandatory, likely opposed by customers and the utility due to high implementation cost; (2) If optional, few would object, unless the implementation cost spills over to other customer classes.

Table 5-2. Pros and Cons of Rate Design Forms *(continued)*

Program Type	Criteria				
	Avoided Cost Benefits and Utility Incentives	Energy and Peak Reductions	Customer Incentive and Bill Impact	Impact on Non-Participants	Implementation and Transition Issues
Dynamic Rates Nonfirm http://www.pacificorp.com/Regulatory_Rule_Schedule/Regulatory_Rule_Schedule2220.pdf	**Pro:** (1) Provides emergency load relief to support system reliability; (2) Implements efficient rationing. **Con:** (1) Does not track costs; (2) Potentially high implementation cost.	**Pro:** (1) Can achieve load reductions to meet system needs; (2) Applicable to both gas and electric service. **Con:** Unlikely to encourage investment in energy efficiency measures.	**Pro:** Bill savings compensate customer for accepting lower reliability.	**Pro:** Little impact, unless the utility offers a curtailable rate discount that exceeds the utility's expected cost savings.	**Pro:** (1) If optional, non-participants would not object unless discount is "excessive"; (2) If mandatory, different levels of reliability (at increasing cost) would need to be offered. **Con:** Complicated notice and monitoring requirements.
Two-Part Rates http://www.aepcustomer.com/tariffs/Michigan/pdf/MISTD4-28-05.pdf:	**Pro:** Allows rate to be set at utility avoided cost. **Con:** Requires establishing customer baseline, which is subject to historical usage, weather, and other factors.	**Pro:** Can be used to encourage or discourage peak usage depending on characteristics of "part two" rate form.	**Pro:** Provides incentives for changes in customer's usage. Therefore, no change in usage results in the same bill.	**Pro:** Non-participants are held harmless.	**Pro:** Complexity can be controlled through design of "part two" rate form. **Con:** (1) Customers might not be accustomed to the concept; (2) Difficult to implement for many smaller customers.
Demand Charges http://www.sce.com/NR/sc3/tm2/pdf/ce30-12.pdf	**Pro:** Reflects the customer's usage of the utility infrastructure. **Con:** Does not consider the duration of the usage (beyond 15 minutes or one hour for electric).	**Pro:** Can achieve load reductions. **Con:** Might not achieve substantial annual reductions.	**Pro:** Provides customers with incentive to reduce peak usage and flatten their usage profile. **Con:** If mandatory, could result in large bill increases for users who cannot change their usage pattern.	**Pro:** If mandatory, little average impact, but can be large on some customers. **Con:** If optional, potentially large impact due to free riders, but this can be mitigated by a careful design.	**Con:** (1) If mandatory, likely opposed by customers and the utility due to high implementation cost; (2) If optional, few would object, unless the implementation cost spills over to other customer classes.
Discount for Efficiency, Benefit Sharing, etc. http://www.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/51362.htm http://www.pacificorp.com/Regulatory_Rule_Schedule/Regulatory_Rule_Schedule7794.pdf	**Pro:** Incentive can be tied directly to avoided costs, without the need to change overall rate design. **Con:** Only a portion of the benefits are reflected in the incentive, as rate savings will still be a factor for most options.	**Pro:** Utilities generally have control over what measures are eligible for an incentive, so the mix of peak and energy savings can be determined during program design. **Con:** Impacts might be smaller than those attainable through mandatory rate programs.	**Pro:** (1) Provides direct incentive for program participation, plus ongoing bill reductions (for most options); (2) Does not require rate changes. **Con:** Existing rate forms might impede adoption because of overly low bill savings.	**Pro:** Reflects the characteristics of the underlying rate form.	**Pro:** Implementation simplified by the ability to keep status quo rates. **Con:** Places burden for action on the energy efficiency implementer, whereas a mandatory rate change could encourage customers to seek out efficiency options.
Energy Efficiency Customer Rebate Programs (e.g., 20/20 program in California) www.sce.com/RebatesandSavings/2020 www.sdge.com/tm2/pdf/20-20-TOU.pdf www.pge.com/tariffs/pdf/EZ-2020.pdf	**Pro:** Can avoid more drastic rationing mechanisms when resources are significantly constrained. **Con:** Customer discounts are not set based on utility cost savings, and therefore these programs might over-reward cutomers who qualify.	**Pro:** (1) Links payment of incentive directly to metered energy savings; (2) Easy to measure and verify. **Con:** Focused on throughput and not capacity savings.	**Pro:** (1) Provides a clear incentive to customers to reduce their energy usage, motivates customers, and gets them thinking about their energy usage; (2) Can provide significant bill savings; (3) Doesn't require customers to sign up for any program and can be offered to everyone.	**Con:** Shifts costs to non-participants to the extent that the rebate exceeds the change in utility cost.	**Pro:** Very successful during periods when public interest is served for short-term resource savings, (e.g. energy crisis.) **Con:** Implementation and effectiveness might be reduced after being in place for several years.

On-Bill Financing

The primary function of on-bill financing is to remove the barrier presented by the high first-time costs of many energy efficiency measures. On-bill financing allows the customer to pay for energy efficiency equipment over time, and fund those payments through bill savings. On-bill financing can also deliver financial benefits to the participants by providing them access to low financing costs offered by the utility. An example of on-bill financing is the "Pay As You Save" (PAYS) program, which provides upfront funding in return for a monthly charge that is always less than the savings.[7]

Pros and Cons of Various Designs

Rate design involves tradeoffs among numerous goals. Table 5-2 summarizes the pros and cons of the various rate design forms from various stakeholder perspectives, considering implementation and transition issues. In most cases, design elements can be combined to mitigate weaknesses of any single design element, so the table should be viewed as a reference and starting point.

Successful Strategies

Rate design is one of a number of factors that contribute to the success of energy efficiency programs. Along with rate design, it is important to educate customers about their rates so they understand the value of energy efficiency investment decisions. Table 5-3 shows examples of four states with successful energy efficiency programs and complementary rate design approaches. Certainly, one would expect higher rates to spur energy efficiency adoption, and that appears to be the case for three of the four example states. However, Washington has an active and cost-effective energy efficiency program, despite an average residential rate far below the national average of 10.3 cents per kWh. (EIA, 2006)

Table 5-3. Conditions That Assist Success

	California	Washington State	Massachusetts	New York
Rate Forms and Cost Structures	Increasing tier block rates for residential (PG&E, SCE, and SDG&E). Increasing block rate for residential gas (SDG&E). http://www.pge.com/tariffs/pdf/E-1.pdf http://www.sce.com/NR/sc3/tm2/pdf/ce12-12.pdf http://www.sdge.com/tm2/pdf/DR.pdf http://www.sdge.com/tm2/pdf/GR.pdf	Increasing tier block rates for residential electric (PacifiCorp). Gas rates are flat volumetric (Puget Sound Electric [PSE]). High export value for electricity, especially in the summer afternoon. http://www.pacificorp.com/Regulatory_Rule_Schedule/Regulatory_Rule_Schedule2205.pdf	Flat electricity rates per kWh with voluntary TOU rates for distribution service (Massachusetts Electric). http://www.nationalgridus.com/masselectric/non_html/rates_tariff.pdf	Increasing tier rates for residential (Consolidated Edison). http://www.coned.com/documents/elec/201-210.pdf
Resource and Load Characteristics	Summer electric peaks. Marginal resources are fossil units. High marginal cost for electricity, especially in the summer afternoon. Import transfer capability can be constrained. Winter gas peaks, although electric generation is flattening the difference. http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf	Winter peaking electric loads, but summer export opportunities. Heavily hydroelectric, so resource availability can vary with precipitation. Gas is winter peaking. http://www.nwcouncil.org/energy/powersupply/outlook.asp http://www.nwcouncil.org/energy/powerplan/plan/Default.htm http://www.pse.com/energyEnvironment/supplyPDFs/II--Summary%20Charts%20and%20Graphs.pdf	Part of Indpendant System Operator New England (ISO-NE), which is summer peaking. http://www.nepool.com/trans/celt/report/2005/2005_celt_report.pdf	High summer energy costs and capacity concerns in the summer for the New York City area. http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/newyork.html

[7] See http://www.paysamerica.org/.

Table 5-3. Conditions That Assist Success *(continued)*

	California	Washington State	Massachusetts	New York
Average Residential Electric Rates	13.7 cents/kWh (EIA, 2006)	6.7 cents/kWh (EIA, 2006)	17.6 cents/kWh (EIA, 2006)	15.7 cents/kWh (EIA, 2006)
Market and Utility Structure	Competitive electric generation and gas procurement. Regulated wires and pipes. http://www.energy.ca.gov/electricity/divestiture.html http://www.cpuc.ca.gov/static/energy/electric/ab57_briefing_assembly_may_10.pdf	Vertically integrated. http://www.wutc.wa.gov/webimage.nsf/63517e4423a08de988256576006a80bc/fe15f75d7135a7e28825657e00710928!OpenDocument	Competitive generation. Regulated wires. http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/mass.html	Competitive generation. Regulated wires. http://www.nyserda.org/sep/sepsection2-1.pdf
Political and Administrative Actors	Environmental advocacy in the past and desire to avoid another energy capacity crisis. Energy efficiency focuses on electricity. http://www.energy.ca.gov/2005publications/CEC-999-2005-015/CEC-999-2005-015.PDF http://www.energy.ca.gov/2005publications/CEC-999-2005-011/CEC-999-2005-011.PDF http://www.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/49757.htm http://www.cpuc.ca.gov/static/energy/electric/energy+efficiency/about.htm	Strong environmental commitment and desire to reduce susceptibility to market risks. http://www.nwenergy.org/news/news/news_conservation.html	DSM instituted as an alternative to new plant construction in the late 1980s and early 1990s (integrated resource management). Energy efficiency now under the oversight of Division of Energy Resources. http://www.mass.gov/Eoca/docs/doer/pub_info/ee-long.pdf	PSC established policy goals to promote competitive energy efficiency service and provide direct benefits to the people of New York. On 1/16/06, Governor George E. Pataki unveiled "a comprehensive, multi-faceted plan that will help reduce New York's dependence on imported energy." http://www.getenergysmart.org/AboutNYES.asp http://www.ny.gov/governor/press/06/0116062.html
Demand-Side Management (DSM) Funding	System benefits charge (SBC) and procurement payment. http://www.cpuc.ca.gov/static/energy/electric/energy+efficiency/ee_funding.htm	SBC. http://www.wutc.wa.gov/webimage.nsf/8d712cfdd4796c8888256aaa007e94b4/0b2e39343c0be04a88256a3b007449fe!OpenDocument	SBC. http://www.mass.gov/Eoca/docs/doer/pub_info/ee-long.pdf	SBC. http://www.getenergysmart.org/AboutNYES.asp

Part of Washington's energy efficiency efforts can be explained by the high value for power exports to California, and partly by the regional focus on promoting energy efficiency. Washington and the rest of the Pacific Northwest region place a high social value on environmental protection, so Washington might be a case where the success of energy efficiency is fostered by high public awareness, and the willingness of the public to look beyond the short-term out-of-pocket costs and consider the longer term impacts on the environment.

The other three states shown in Table 5-3 share the common characteristics of high residential rates, energy efficiency funded through a system benefits surcharge, and competitive electric markets. The formation of competitive electric markets could have also encouraged energy efficiency by: (1) establishing secure funding sources or energy efficiency agencies to promote energy efficiency, (2) increasing awareness of energy issues and risks regarding future energy prices, and (3) the entrance of new energy agents promoting energy efficiency.

Key Findings

This chapter summarizes the challenges and opportunities for employing rate designs to encourage utility promotion and customer adoption of energy efficiency. Key findings of this chapter include:

- Rate design is a complex process that balances numerous regulatory and legislative goals. It is important to recognize the promotion of energy efficiency in the balancing of objectives.

- Rate design offers opportunities to encourage customers to invest in efficiency where they find it to be cost-effective, and to participate in new programs that provide innovative technologies (e.g., smart meters) to help customers control their energy costs.

- Utility rates that are designed to promote sales or maximize stable revenues tend to lower the incentive for customers to adopt energy efficiency.

- Rate forms like declining block rates, or rates with large fixed charges reduce the savings that customers can attain from adopting energy efficiency.

- Appropriate rate designs should consider the unique characteristics of each customer class. Some general rate design options by customer class are listed below.

— *Residential.* Inclining tier block rates. These rates can be quickly implemented for all residential and small commercial and industrial electric and gas customers. At a minimum, eliminate declining tier block rates. As metering costs decline, also explore dynamic rate options for residential customers.

— *Small Commercial.* Time of use rates. While these rates might not lead to much change in annual usage, the price signals can encourage customers to consume less energy when energy is the most expensive to produce, procure, and deliver.

— *Large Commercial and Industrial.* Two-part rates. These rates provide bill stability and can be established so that the change in consumption through adoption of energy efficiency is priced at marginal cost. The complexity in establishing historical baseline quantities might limit the application of two-part rates to the larger customers on the system.

— *All Customer Classes.* Seasonal price differentials. Higher prices during the higher cost peak season encourage customer conservation during the peak and can reduce peak load growth. For example, higher winter rates can encourage the purchase of more efficient space heating equipment.

- Energy efficiency can be promoted through non-tariff mechanisms that reach customers through their utility bill. Such mechanisms include:

— *Benefit Sharing Programs.* Benefit sharing programs can resolve situations where normal customer bill savings are smaller than the cost of energy efficiency programs.

— *On-Bill Financing.* Financing support can help customers overcome the upfront costs of efficiency devices.

— *Energy Efficiency Rebate Programs.* Programs that offer discounts to customers who reduce their energy consumption, such as the 20/20 rebate program in California, offer clear incentives to customers to focus on reducing their energy use.

- More effort is needed to communicate the benefits and opportunities for energy efficiency to customers, regulators, and utility decision-makers.

Recommendations and Options

The National Action Plan for Energy Efficiency Leadership Group offers the following recommendations as ways to overcome many of the barriers to energy efficiency in rate design, and provides a number of options for consideration by utilities, regulators, and stakeholders *(as presented in the Executive Summary):*

Recommendation: Modify ratemaking practices to promote energy efficiency investments. Rate design offers opportunities to encourage customers to invest in efficiency where they find it to be cost-effective, and to participate in new programs that bring them innovative technologies (e.g., smart meters) to help them control their energy costs.

Options to Consider:

- Including the impact on adoption of energy efficiency as one of the goals of retail rate design, recognizing that it must be balanced with other objectives.

- Eliminating rate designs that discourage energy efficiency by not increasing costs as customers consume more electricity or natural gas.

- Adopting rate designs that encourage energy efficiency, considering the unique characteristics of each customer class, and including partnering tariffs with other mechanisms that encourage energy efficiency, such as benefit sharing programs and on-bill financing.

Recommendation: Broadly communicate the benefits of, and opportunities for, energy efficiency. Experience shows that energy efficiency programs help customers save money and contribute to lower cost energy systems. But these impacts are not fully documented nor recognized by customers, utilities, regulators and policymakers. More effort is needed to establish the business case for energy efficiency for all decision-makers, and to show how a well-designed approach to energy efficiency can benefit customers, utilities, and society by (1) reducing customers bills over time, (2) fostering financially healthy utilities (return on equity [ROE], earnings per share, debt coverage ratios unaffected), and (3) contributing to positive societal net benefits overall. Effort is also necessary to educate key stakeholders that, although energy efficiency can be an important low-cost resource to integrate into the energy mix, it does require funding just as a new power plant requires funding. Further, education is necessary on the impact that energy efficiency programs can have in concert with other energy efficiency policies such as building codes, appliance standards, and tax incentives.

Option to Consider:

- Communicating on the role of energy efficiency in lowering customer energy bills and system costs and risks over time.

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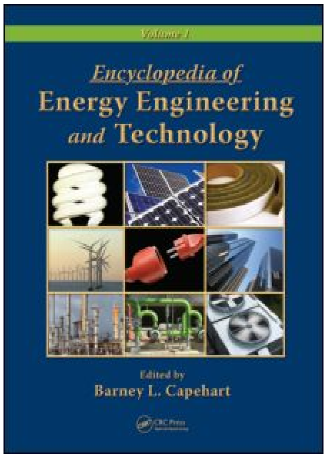

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Pricing Programs: Time-of-Use and Real Time

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Pricing Programs: Time-of-Use and Real Time

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Abstract

This article surveys numerous pricing designs for improving economic efficiency in all market segments. Electricity is a very capital-intensive industry characterized by a significant peak load problem. Expensive generating plants have to be installed to meet peak loads that are only encountered for a few hundred hours a year. This raises the cost of electricity to all consumers. Average cost pricing, the staple of the industry in which rates do not vary by time of use, compounds the problem by creating cross-subsidies. Customers with flatter load shapes subsidize those with peakier load shapes.

The problem can be alleviated by modifying electricity pricing practices to allow time-variation in costs. This would provide customers an incentive to lower peak usage, either by curtailing or shifting their activities. In addition, it would eliminate unfair and economically unjustified cross subsidies. But the potential benefits of time-varying pricing have yet to be fully realized. Many barriers stand in the way of reform, including economic, technological and political. Of all these barriers, the most formidable ones are the political ones. They have to be resolved by modifying the legal and regulatory framework through which electricity pricing is determined.

INTRODUCTION

Time-of-use (TOU) pricing and real time pricing (RTP) programs are designed to lower system costs for utilities and bring down customer bills by raising prices during expensive hours and lowering them during inexpensive hours. They differ in, that the former fixes the price and time periods in advance while the latter fixes neither the price nor the time period in advance. Thus, TOU rates can be considered static while RTP rates can be considered dynamic, even though before feature time-varying prices. Other rate designs bridge the gap between these two rate designs, as shown below.

Time-of-use pricing (TOU). This rate design features prices that vary by time period, and are higher in peak periods and lower in off-peak periods. The simplest rate involves just two pricing seasons, with prices being higher during the peaking season. A time-of-day rate is slightly more complex and involves two pricing periods within a day, a peak period and an off-peak period. More complex rates have one or more shoulder periods and seasonal variation.

Critical peak pricing (CPP). This rate design layers a very high price during a few critical hours of the year. It can also be combined with a TOU rate. Typically, a CPP rate is only used on 12–15 days a year. These days are called the day before or the day of the critical peak price.

Extreme day pricing (EDP). This rate design is similar to CPP, except that the higher price is in effect for all 24 h for a maximum number of critical days, the timing of which is unknown until a day ahead.

Extreme day CPP (ED-CPP). This rate design is a variation of CPP in which the critical peak price applies to the critical peak hours on extreme days but there is no TOU pricing on other days.

Real time pricing (RTP). This rate design features prices that vary hourly or sub-hourly all year long, for some or all of a customer's load. Customers are notified of the rates on a day-ahead or hour-ahead basis.

Each of these rates exposes customers to varying amounts of price variance. Customers can lower their expected (average) price by taking more risks. For example, RTP rates are riskiest from the customer's viewpoint since they face wholesale prices that vary in real time, but they will most likely be associated with the lowest average price. Critical peak pricing rates carry less pricing uncertainty for customers, since customers know the prices ahead of time and the time for which these prices will be in effect is limited. However, the average price is likely to be higher than that for RTP rates. At the other end of the spectrum are rates that do not vary over the hours of the day and only vary seasonally. They provide the highest rate predictability to customers but are also likely to carry the highest average price.

TIME-OF-USE PRICING

Time-of-use pricing is commonplace in developed economies at all stages of market restructuring. Electricite de France (EDF) operates the most successful example of

Keywords: Electricity pricing; Rate design; Economic efficiency; Demand response.

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TOU pricing. Currently, a third of its population of 30 million customers is estimated to be on TOU pricing. This pricing design was first introduced for residential customers in 1965 on a voluntary basis, having been first applied in the country to large industrial customers as the Green Tariff in 1956. The French model served for many years as a benchmark for many countries in Latin America. For example, in Brazil, it was introduced as the "Horo-sazonal" tariff, which divides the day into peak and off peak periods and the year into dry and wet seasons. The idea was to continue all the way to the residential customer (yellow tariff), but it never came to fruition.

Time-of-use rates have been mandatory in California for all customers above 500 kW since 1978, as a statewide policy response to the energy crisis of 1973. These rates are mandatory in several U.S. states but the size threshold varies by state.

Residential TOU rates are offered on a voluntary opt-in basis by utilities in all types of climates within the U.S., including Pepco in the Washington, DC area and the Salt River Project in the Phoenix area. The simplest variation involves two time periods. An example is the residential rate design offered by Pacific Gas & Electric Company (PG&E) in central and northern California. During the summer months, from noon to six P.M. on weekdays, electricity costs three times as much as during all other hours of the week. During the winter months, the price differential is smaller.

Another example is the project that was implemented by Puget Sound Energy (PSE) in the suburbs of Seattle. In May 2001, as a response to the power crisis in the Western states, PSE designed and implemented a TOU rate for its residential and small commercial customers. It involved four pricing periods. The morning and evening periods were the most expensive periods, followed by the mid-day period and the economy period. Unlike most TOU rates, which feature significant differentials between peak and off-peak prices, PSE's TOU rate featured very modest price differentials between the peak and off-peak periods, reflecting the hydro-based system in the Northwest.

The peak price was about 15% higher than the average price customers had faced prior to being moved to the TOU rate and the off-peak price was about 15% lower. To keep the rate simple, there was no seasonal variation in prices.

Puget Sound Energy placed about 300,000 customers on the rate, but they could opt-out to the standard rate if they so desired. There was no additional charge to participate in the rate. During the first year of the program, less than half of one percent elected to opt-out of the rate. Customer satisfaction with the rate was high. In focus groups, customers identified several benefits of the TOU rate besides bill savings, including greater control over their energy use; choice about which rate to be on; social responsibility; and energy security. PSE also provided a website to customers where they could review their load shapes for the past seven days.

Puget Sound Energy had a rate case settlement in June 2002. Under the terms of the settlement, the program became an opt-in program for new customers. The peak/off-peak rate differential of the TOU rate was reduced from 14 to 12 mils/kWh (A mil is a thousandth of a dollar). A monthly fee of $1 a month, about 80% of the estimated variable cost of providing TOU meter reading, was levied on participating customers. Finally, each quarter PSE would notify customers of their savings (or losses) on the program, and it would switch all customers to the lower-cost rate (flat or TOU) in August 2003.

In October 2002, PSE sent customers their first quarterly report. For 94% of the customers, this report showed that they were paying an extra 80 cents/month by participating in the TOU pilot, comprised of the difference between 20 cents of power cost savings and a dollar of incremental meter reading costs. This was marked in contrast to the first year of the program when, prior to charging customers any part of the TOU meter reading costs, over 55% of residential customers experienced bill savings by being on the TOU rate.

Even though the report was for a single quarter, 10% of the participating customers chose to opt-out of the program between July 1 and October 31. At the same time, 1.8% of new customers opted into the program.

Media coverage was very negative and featured interviews with customers claiming that they had shifted almost half of their load from peak to off-peak periods, only to find out that they had lost money. PSE pulled the plug on a program that had become the most visible national symbol of a utility's commitment to time-varying pricing, and agreed to refund the increased amounts to participating customers.

Lessons Learned From the PSE TOU Rate

Five lessons can be drawn from PSE's TOU program.

- Customers do shift loads in response to a TOU price signal, even if the price signal is quite modest. According to an independent analysis, customers consistently lowered peak period usage by 5% per month over a 15-month period.
- It is important to manage customer expectations about bill savings.
- Customers should be educated on the magnitude of bill savings they can expect from specific load shifting activities.
- It is desirable to conduct a pilot program involving a few thousand customers before offering a rate to hundreds of thousands of customers.
- Finally, and most importantly, any program should make a majority of the customers better off, or it should not be offered.

Developing a TOU Rate

It is fairly straightforward to develop a TOU rate design. The following sidebar shows the steps involved in developing a "revenue-neutral" TOU rate. Such a rate would leave the average customer's bill unchanged if that customer chose to make no adjustments in their pattern of usage. Of course, a customer who uses less power in the peak period than the average customer would be made better off (compared to his or her situation on the standard rate) by the rate even without responding to the rate and a customer who uses proportionately more power in the peak period than the average customer would be made worse off by the rate if he or she did not respond to the rate.

Sidebar 1 brings out the type of information that is needed to develop a TOU rate.

CRITICAL PEAK PRICING

Under this rate design, customers are on TOU prices for most hours of the year but additionally face a much higher price during a small number of critical hours when system reliability is threatened or very high prices are encountered in wholesale markets because of extreme weather conditions and similar factors. In 1993, EDF (France) introduced a new rate design, tempo, and now has over 120,000 residential customers on it. The program features two daily pricing periods and three types of days. The year is divided into three types of days, named after the colors of the French flag. The blue days are the most numerous (300) and least expensive; the white days are the next most numerous (43) and mid-range in price; and the red days are the least numerous (22) and the most expensive. The ratio of prices between the most expensive time period (red peak hours) and the least expensive time period (blue off-peak hours) is about 15–1, reflecting the corresponding ratio in marginal costs.

The tempo rate does not offer a fixed calendar of days, but customers can learn what color will take effect the next day by checking a variety of different sources:

- Consulting the Tempo Internet website: www.tempo.tm.fr
- 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
- 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 rates associated with the tempo program and with EDF's standard TOU rate are shown in Fig. 1.

Sidebar 1 Developing a TOU rate involves several steps

Existing flat rate	
Per-customer revenue requirement	\$100
Per-customer monthly usage	1000 kWh
Average price	\$0.10/kWh
Revenue neutral TOU rate	
Estimate peak usage	200 kWh
Estimate off-peak usage	800 kWh
Set peak price = peak marginal cost	\$0.20/kWh
Set off-peak price = off-peak marginal cost	\$0.075 kWh
Given class revenue requirement	\$100
Given monthly usage	1000 kWh
TOU rate with load shifting	
Estimate price elasticity	−0.2
Estimate new peak usage	160 kWh[a]
Estimate new off-peak usage	840 kWh
Estimate new monthly usage	1000 kWh
Estimate new per-customer monthly bill	\$95
Estimate bill savings = per-customer revenue loss	\$100 − \$95 = \$5

[a]These changes in usage for the peak and off-peak period are estimated by using the percent changes in peak and off-peak prices and the estimated price elasticity of demand.

Critical Peak Pricing With 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 or non-technology enabled CPP rates.

Two utilities, GPU in Pennsylvania and American Electric Power in Ohio, conducted small-scale pilot programs in the 1980s 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 retail price of electricity rises to a much higher level (e.g., 50 cents/kWh in the GPU pilot). The number of hours during which this price can be charged is small (e.g., 100–200 h) and the customer knows what the critical price will be ahead of time, but does not know when the price may be called.

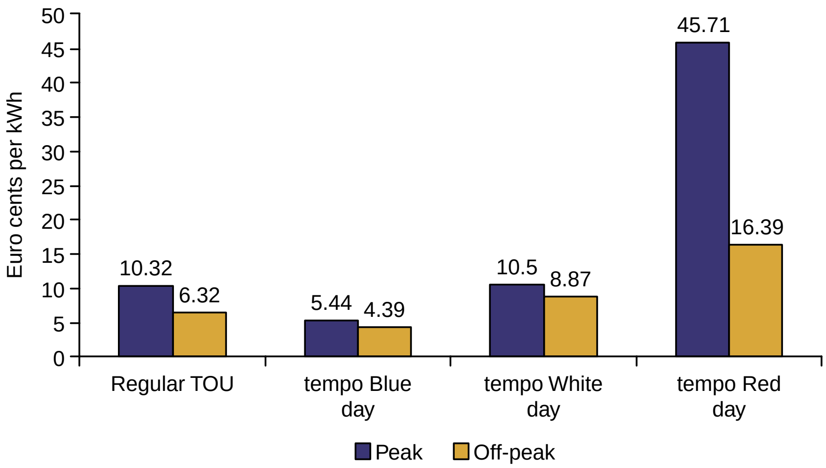

Fig. 1 EDF's *tempo* and standard TOU rates.

The TransText device incorporates an advanced communication feature that lets customers know that a critical period is approaching and it can be programmed so that the customer's thermostat is automatically adjusted when prices exceed a certain level. Using this technology, American Electric Power found significant load shifting, with estimated peak demand reductions of 2–3 kW per customer during on-peak periods and of 3.5–6.6 kW during critical peak periods. These critical peak reductions represented a drop of nearly 60% of a typical customer's peak load during the winter period.

The GPU experiment produced similar results, showing elasticities of substitution that ranged from −0.31 to −0.40, significantly higher than the elasticities associated with traditional TOU rates, which have averaged −0.14 in a range of studies. These elasticities were estimated by comparing customer loads on days when control was being exercised with days when control was not being exercised.

Another example is provided by Gulf Power Company's *Good Cents Select* program in Florida. 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% of all hours in the year, where the peak period price of $0.093/kWh is roughly 60% higher than the standard (flat) tariff price and approximately twice the intermediate (shoulder) price. For the remaining 1% 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 and it is called during the day when critical conditions are encountered. In conjunction with this rate, participating customers 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 2-year period have equaled roughly 22% compared with a control group, while reductions during critical-peak periods have equaled almost 42%. Diversified coincident peak demand reductions have exceeded more than 2 kW per customer. This voluntary program has been in place for less than a year, and Gulf Power has already signed up more than 3000 high use customers. It hopes to attract 40,000 customers over the next 10 years, representing about 10% 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% satisfaction rating.

The Gulf Power program is targeted at high use customers, just like the EDF program. Customer savings are large enough to offset the program costs. Both rates have significant peak to off-peak differentials as well. Because of these two factors, the programs have been successful. The PSE program failed in part because it had weak peak to off-peak differential and in part because it did not target the large customers.

California's Pricing Experiment

The state of California conducted a statewide pricing pilot (SPP) during the 2003–2005 timeframe to test customer response to a variety of pricing options, including TOU rates and CPP rates. In California, standard residential tariffs involve an "inverted tier" design in which the price of power rises with electricity usage. The typical residential customer pays an average price of about 13 cents/kWh. Within the SPP, customers on TOU and CPP rates pay a higher price during the five-hour peak period that lasts from 2 P.M. to 7 P.M. on weekdays and a lower price during the off-peak period, which applies during all other hours.

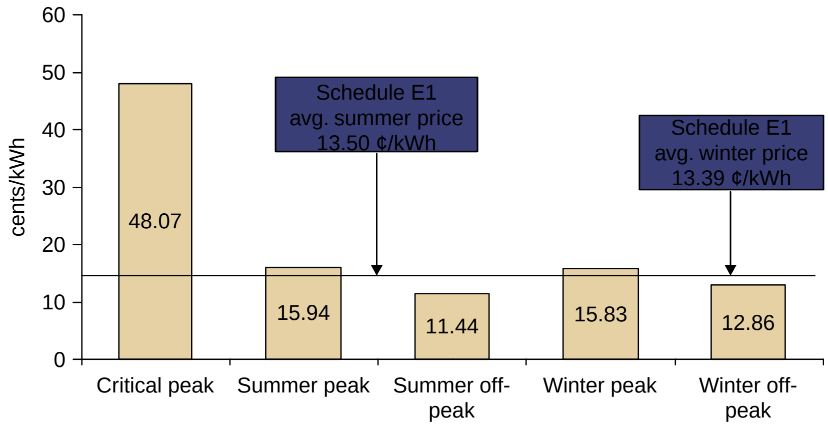

Fig. 2 Critical-peak pricing (CPP) tariff.

Each TOU and CPP rate involves two sets of peak/off-peak prices, to allow for precise estimation of the elasticities of demand. On average, customers on TOU rates are given a discount of 23% during the off-peak hours and are charged a price of around 10 cents. They are charged a price of 22 cents during the peak hours, which is 69% higher than their standard rate. Thus, with TOU rates, customers are given a strong incentive to curtail peak usage and to shift usage to off-peak periods. However, the incentive is much greater on selected days for customers on CPP rates, who are charged, on average, a price of 64 cents during the peak hours on 12 summer days, i.e., prices are nearly five times higher than the standard price. On the peak hours of other days and the off-peak hours of all days they face prices that are slightly lower than the prices faced by TOU customers during these periods. Fig. 2 shows the CPP tariffs that were used in the California experiment.

Analysis of data from the California experiment indicates that CPP rate customers face "rifle shot" price signals that can be very effective at reducing peak demand, thus dampening wholesale prices and obviating the need for building costly power plants that would run for only a few hundred hours a year. Customers are likely to respond to higher peak prices by reducing peak usage, e.g., by reducing air conditioning usage, and perhaps by shifting some peak period usage associated with laundry, dish-washing and cooking activities to lower cost off-peak periods. They may also be raising off-peak use in response to lower off-peak rates by raising air conditioning usage, increasing lighting levels, and so on. Finally, since prices have changed in the peak and off-peak periods, the average price for electricity over the day may have changed for some customers as well. This would trigger additional changes in usage.

Fig. 3 shows the changes in customer load shapes caused by the CPP tariff in customers who were located in the San Diego Gas and Electric service area. The black line shows the usage of the control group of customers. The gray line shows the usage of customers who were equipped with a smart thermostat that received a communication signal from the utility during critical hours, which raised the set point of the thermostat. Their tariff was unchanged from that of the control group. The difference between the two lines is noticeable and suggests that remotely controlling the thermostat lowers peak usage. The white line shows the

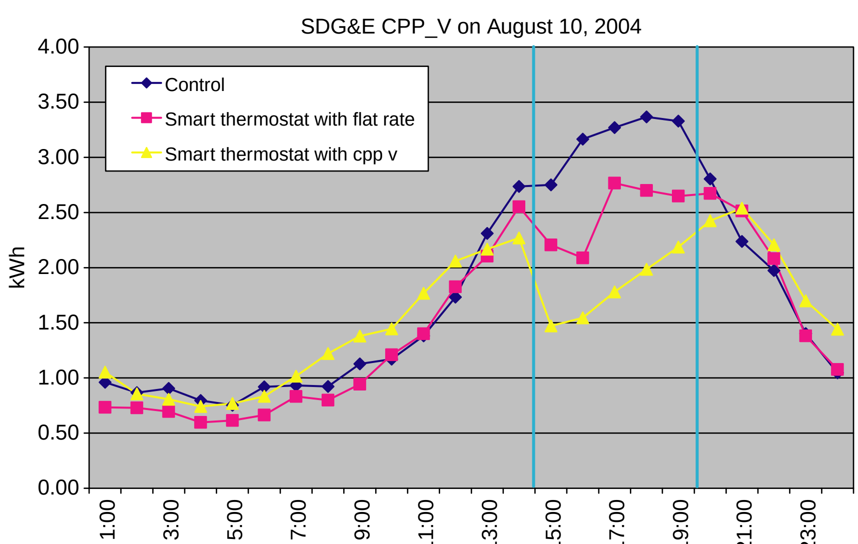

Fig. 3 Changes in customer load shapes.

usage of customers who were equipped with a smart thermostat and who also were placed on the CPP tariff. They show a greater drop than customers who had the smart thermostat but who were not placed on the CPP tariff.

REAL-TIME PRICING FOR RESIDENTIAL CUSTOMERS

The Chicago Community Energy Cooperative (Co-op) has implemented a market-based RTP pricing plan for residential customers, in conjunction with the local electric utility, CommEd. The utility provides the rate and the metering/billing system while the Co-op provides customer notification (via a web site, e-mail and telephone), education, and energy management tools (Fig. 4).

The pilot program is intended to model the bundled rate/market rate differential in the post-2006 market environment when the rate freeze is lifted. It involves RTP prices on a day-ahead basis for the generation portion of the rate. The prices are capped at 50 cents/kWh. The project is designed to estimate the magnitude of customer response to hourly energy pricing and understand the drivers of responsiveness. This is a 3-year experimental program that commenced in January 2003.

In the first year of the program, 750 customers were enrolled. Of these, 100 are in a control group. The summer of 2003 was mild in terms of both temperatures and prices. For example, the number of days with a maximum temperature higher than 90°C was 10 versus a historical average of 18. The maximum price was 12.39 cents/kWh, versus a price of 38.11 cents/kWh during the crisis years of 2000–2002.

Analysis of customer loads during the first year indicates that participants responded to the higher prices they faced during the peak periods. A price elasticity of −0.042 was estimated over the full range of prices. Over half of all participants showed significant response to high price notifications. Aggregate demand reduction was as high as 25% during the notification period. Over 80% of the participants reported modifying their air conditioning usage, and over 70% reported modifying their clothes-washing patterns.

Multifamily households as a group were more price-responsive than single-family households. Households with window air conditioners maintained their price responsiveness better across multiple high-priced hours than single-family households, who started out strong but whose responsiveness tended to taper off during the high priced periods.

Customer satisfaction was very high with the program. The program was "quick and easy" for 82% of the participants and "time consuming and difficult" for 1%. Participants saved on average $12/month or 20% of their monthly bill.

The project has shown that residential customers are a viable market for RTP. They represent a key target market, since residential load is a major contributor to system peak. And giving residential customers a choice of pricing options may be the only way to give them a meaningful choice in restructured power markets.

REAL-TIME PRICING FOR COMMERCIAL AND INDUSTRIAL CUSTOMERS

Utilities in the Southeastern U.S. have implemented RTP rates for about 2000 customers on a day-ahead or hour-ahead basis. These companies include Georgia Power,

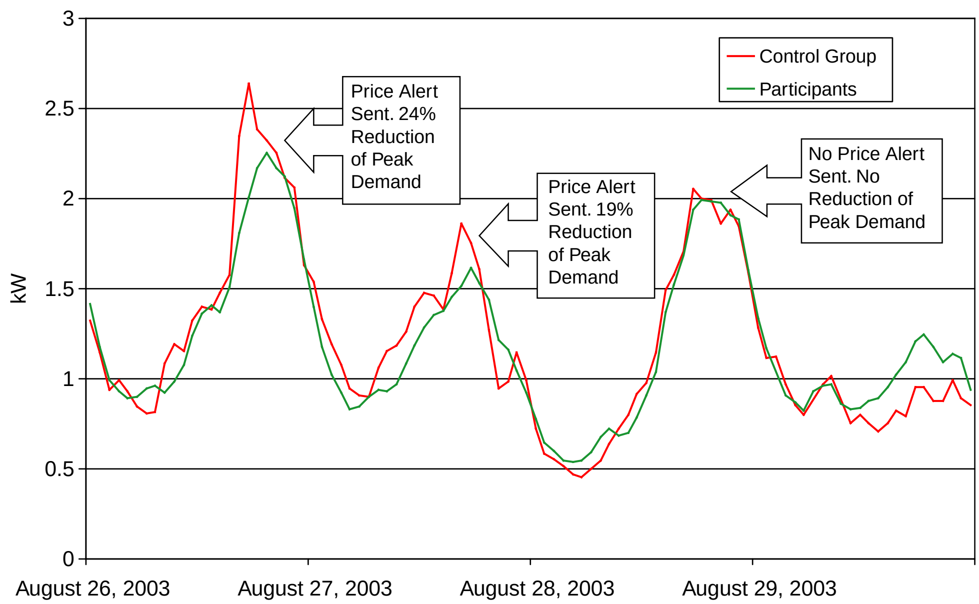

Fig. 4 Impact of real time pricing on Chicago Residences.

Duke Power and the Tennessee Valley Authority. The Georgia Power program is discussed in detail below.

Before describing the Georgia Power program, we note that RTP rates were probably first used by ESKOM, the state-owned utility in South Africa, for its largest customers, including the fabled gold mines. ESKOM has 1400 MW of load on day-ahead RTP. These customers drop their load by 350–400 MW for up to three consecutive hours when faced with high prices. While RTP is set up on a day-ahead basis, customer response is not used to optimize the dispatch of the power system. Electricity prices are based on the Pool Output Price, and do not change in response to changes in customer demand that may be induced by RTP. The utility is not aggressively marketing the program for this reason. It hopes that once a competitive energy market has been created, with a functioning Power Exchange, RTP will then be able to play its proper role in system operations.

If RTP had been implemented in California during the summer of 2000, much of the power crisis that developed in May 2000 would have abated within a month, rather than persisting for a year. If only a small proportion of the total customers had bought power on RTP, statewide peak demand would have dropped by 2.5%, or 1250 MW. During the peak hours, this would have lowered wholesale market prices by 20%. The state's power costs for the summer would have dropped by 6% (Faruqui, Ahmad, Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, "Getting out of the Dark," *Regulation*, Fall 2001, pp. 58–62).

RTP at Georgia Power

Georgia Power runs the worlds largest and possibly the most successful RTP program. The company estimates that during emergency conditions, its customers drop demand by 17%, freeing up 800 MW of capacity. A load drop of this magnitude eliminates the need for several expensive power plants that would otherwise be needed for meeting the peak load.

Program Background

Georgia law permits customers with 900 kW or more of connected load to put their load out to bid, and be served by any supplier in the state. In the late 1980s, Georgia Power was competing for these customers with almost 100 rural cooperatives and municipal utilities. In part to increase its competitiveness, Georgia Power began looking into RTP. In 1992, it began a 2-year controlled pilot, with the goals of increasing competitiveness; improving customer satisfaction by giving customers more control over their bills; and curtailing load when needed to balance supply and demand.

Georgia Power was one of the first utilities in the country to develop a two-part RTP tariff, following the lead of Niagara Mohawk in New York that had launched an Hourly Pricing Program in the late 1980s. The utility chose a two-part rather than a one-part rate for several reasons. First, the two-part rate allows the hourly price to more closely reflect the utility's true marginal cost. Second, the two-part rate best represents the "market price." Georgia Power believed a two-part rate would give it an opportunity to work with customers on price protection products. A discussion of price protection products is provided below. In addition, the utility was concerned about revenue stability; with a one-part rate, it would lose some of the contribution to fixed costs when customers curtailed in high priced hours. Georgia Power has expanded its RTP offerings since the 1992 pilot, but the basics of the program and tariff have remained relatively unchanged for almost a decade.

Rate Structure

Customers are billed for "baseline" use at their standard rate and pay (or receive credits) for energy used above (or below) the baseline each hour at the hourly price. The hourly price is composed of a measure of marginal energy costs, line losses, a "risk recovery factor" for forecasting risk (a fixed adder), and—near peaks—marginal transmission costs and outage cost estimates. Marginal transmission costs are triggered by load and temperature. Outage cost estimates are based on loss of load probabilities, as well as customer surveys on the costs of having an outage.

Georgia Power offers a "day-ahead" program, where customers are notified of price schedules by 4 P.M. the day before they go into effect, and an "hour-ahead" program, where customers are given an hour's notice on price. Currently, interruptible customers are served on the hour-ahead program. For these customers, their customer baseline (CBL) drops to their firm contract level during periods of interruption. Customers who do not interrupt to their firm levels pay interruption penalties plus the hourly prices. The utility has filed a tariff with the Public Service Commission that would allow interruptible customers on the day-ahead rate as well. The other difference between the day and hour-ahead rates is that the risk-recovery factor for the day-ahead rate is greater than that for the hour-ahead rate (4 mils/kWh versus 3 mils/kWh), since the utility bears a greater forecast risk.

Setting the Customer Baseline

When Georgia Power began its RTP program, it based a customer's baseline usage, or CBL, on an 8760-point hourly load profile. However, customers often found this CBL confusing, and therefore frustrating. In response to these customers, Georgia Power now offers 360-point CBLs (with 24 average hourly weekday loads per month and six average four-hour weekend day loads, for a total of 30 CBL points per month), and two-point CBLs.

The two-point CBLs simply average usage levels during the peak and off-peak periods.

The majority of customers (basically, the high-load-factor customers) now select the two-point CBL. If the two-point CBL does not seem appropriate based on a customer's usage profile, Georgia Power will usually use a 360-point CBL. Only a very few "unique loads" use the 8760-point CBL today (Our source noted that customers who can "really respond a lot" are typically on the higher point CBLs).

Price Protection Products

Georgia Power offers customers a variety of products that allow customers to influence their exposure to RTP price risk. One product, the adjustable CBL, allows customers to temporarily adjust their CBLs. For example, if customers want to lower their exposure to price volatility, they would increase CBLs. (Customers wanting to raise their CBLs must be on the RTP rate for a year, so that Georgia Power can determine how high the CBL can be raised.) Customers wanting to expose more loads to real-time prices—presumably because they believe it will be a cool summer—can lower their CBLs. Of the roughly 1650 customers on RTP, 600 currently have adjustable CBLs. About 60% of the incremental energy sold on the RTP rate (i.e., usage above baseline) is now protected by this product.

Georgia Power also offers a variety of financial products to limit customers' exposure to RTP price volatility. These products include price caps, contracts for differences, collars, index swaps, and index caps (Georgia Power's price-cap product guarantees that average RTP prices over a specific time period will not go above the cap. Its contract for differences gives a fixed price guarantee on the average RTP price. The collar has a cap and floor on the average RTP price over a specific time period. The index swap is a financial agreement that ties the RTP price to a commodity price index. If the commodity price index increases, so does the RTP price. If it decreases, so does the RTP price. The index cap is a financial agreement that ties an RTP price cap to a commodity price index. As the commodity price increases or decreases, so does the price cap). Georgia Power has sold these Price Protection Products, or PPPs, for 3 years. It currently has 250 contracts with about 90 customers. (Customers have multiple contracts to cover different time periods.) Georgia Power believes that offering these products has not probably increased the number of customers on the RTP program, but it has increased customer satisfaction. The utility has examined whether offering the PPPs has dampened price responsiveness, and has found no evidence of this.

LESSONS LEARNED

Georgia Power's experience highlights a number of lessons that have also been seen at other utilities. First, RTP can deliver substantial peak savingsssas, despite the fact that many customers are not very responsive to price. When the hourly price reached $6.40/kWh, Georgia Power saw 850 MW of load reduction (out of 1500–2000 MW of incremental or above-baseline load) from its RTP customers. Georgia Power also believes that customers have responded to the availability of low off-peak prices by expanding their facilities and business operations in Georgia. In other words, the rate has served to bring economic growth to the state and been a form of strategic electrification while also being a form of load management.

The utility's experience also supports the finding that customers join RTP programs to have access to lower cost power. When hourly prices went up in response to changing market conditions, customers sought price relief, and were granted it by the Georgia Public Services Commission.

Georgia Power has also found that a small percentage of customers are willing to pay for limited protection against price volatility. In response to customer requests, they developed and now sell a variety of risk-management products.

Georgia Power has also found that manufacturers with highly energy-intensive processes, such as chemical and pulp and paper companies are generally the most price responsive customers. It is also learnt that some commercial customers would respond to price. Office buildings, universities, grocery stores, and even a hospital (that changes chiller use based on hourly prices) are all responsive to real-time pricing.

Georgia Power states that the major lesson it has learnt is that education is the key to a successful RTP program. Georgia Power now holds annual, statewide meetings with all its customers to keep them informed about the RTP program. The utility believes its education program has paid off in customer satisfaction.

CONCLUSION

Electricity is a very capital-intensive industry characterized by a significant peak load problem. Expensive generating plants have to be installed to meet peak loads that are only encountered for a few hundred hours a year. This raises the cost of electricity to all consumers. Average cost pricing, the staple of the industry in which rates do not vary by time of use, compounds the problem by creating cross-subsidies. Customers with flatter load shapes subsidize those with peakier load shapes.

The problem can be alleviated by modifying electricity pricing practices to allow time-variation in costs. This would provide customers an incentive to lower peak usage, either by curtailing or shifting their activities. In addition, it would eliminate unfair and economically unjustified cross subsidies. As surveyed in this article, there are numerous pricing designs for improving economic efficiency in all market segments. But the potential benefits of time-varying pricing have yet to be fully realized. Many barriers stand in the way of reform, including economic, technological and political. Of all these barriers, the most formidable ones are the political ones. They have to be resolved by modifying the legal and regulatory framework through which electricity pricing is determined.

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