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Retail Electricity Pricing And Rate Design In Evolving Markets

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EXECUTIVE SUMMARY

This monograph reviews the critical role that efficient rate design needs to play in today's electricity markets, and suggests practical strategies for overcoming historical barriers to implementing such rates.

Chapter 1, Introduction and Background, describes the fundamental role that efficient retail rates need to play in maintaining the reliability and operating efficiency of today's existing electricity system, while ensuring the adequacy and cost-efficiency of tomorrow's system. Efficient retail rates reflect wholesale market prices, which vary by time and sometimes location. Allowing at least some retail customers to have access to time-varying retail rates empowers consumers to take control of their electricity costs (e.g., by curtailing usage during high-cost periods and increasing usage during low-cost periods). This process, known as price-responsive demand (PRD), can produce substantial benefits in terms of lower resource costs and increased economic efficiency.

Traditional rates reflect highly averaged costs (e.g., across diverse customers in broad rate classes, and over many different hours of the year). In contrast, efficient rates offer consumers choices from a range of price structures, including variable rates that reflect different degrees of time-varying costs and fixed rates that include risk premiums for price guarantees. Efficient rates give customers greater choices, recognizing that they have diverse preferences in terms of how much they value rate/bill certainty versus the lowest possible expected cost.

While efficient rates have been studied and debated for at least 30 years, the need for them has undertaken new urgency due to declining reserve margins and transmission congestion in some areas, and the concomitant increase in the variability of wholesale electricity prices. In addition, global market competition and climate change concerns argue for efficient rates that lead to efficient investment and lower resource costs. Recent developments such as the advent of organized wholesale markets which produce transparent hourly market-clearing prices, the increased deployment of advanced metering infrastructures, and regulatory interest in greater price-responsive demand offer new opportunities to implement more efficient retail rates.

Chapter 2, Framework for Efficient Electricity Pricing, elaborates on the properties and forms of efficient electricity pricing. Electric rates are ultimately efficient to the extent they help society decide how much electricity to produce, recognizing that total productive capacity is limited, so that a decision to produce more electricity is a decision to produce less of other things. Electricity costs cover four major areas: customer services, distribution services, transmission facility services, and generation services. Costs for the first three kinds are largely fixed, but generation costs vary substantially over time and location. Reflecting this variability in the marginal cost of generation services is a key feature of efficient rates.

Opportunities for improving economic efficiency exist whenever retail rates are fixed at highly averaged cost levels, while actual market prices vary substantially. Efficient rates can reflect the time-varying nature of market prices in a number of ways, recognizing that the variability in marginal costs tends to be greatest in just a few hours of the year. For example, a rate that is fixed most of the time but which varies under certain high-cost conditions may capture a large portion of the efficiency benefits of a rate whose prices vary every hour. Efficient rates may also be fixed over some time periods so long as they include a premium for the risk that the energy provider bears in making a fixed-price commitment for those time periods. Efficient rates also acknowledge consumers' diverse risk preferences. They therefore offer customers choices which allow them to trade off cost minimization versus price risk management, rather than imposing the same implicit risk premium on all consumers through one-size-fits-all rates.

Among the categories of efficient time-based pricing described in the monograph are: 1) hourly pricing (including basic hourly pricing, block and index pricing, two-part real-time pricing (RTP), and unbundled RTP with self-selected baseline load); 2) daily pricing (including day-type time-of-use (TOU) rate, variable peak rate, critical peak pricing (CPP), variable CPP, CPP linked to a standard tariff, and peak-day rebate); 3) fixed time-of-use pricing, and 4) seasonal flat pricing. Other forms of efficient pricing involve electric vehicle charging rates, and rates related to distributed generation (DG) (including incentives for economic DG, sell-back rates, and standby rates). Although efficient time-based rates have been discussed and tested for at least 30 years (see Appendix B), a new urgency for efficient pricing has been motivated by the introduction of advanced metering and related communication and control technologies, and by a strong perceived need to link wholesale and retail power markets.

Chapter 3, Strategies for Implementing Efficient Retail Pricing, reviews historical barriers to efficient electricity pricing and considers strategies for overcoming those barriers. A review of the pricing plans offered by competitive energy providers in retail access markets illustrates the variety of efficient rates that can evolve under competitive conditions that require linking retail rates to wholesale prices. In addition, setting efficient default rates in retail access markets is important for providing a fair and efficient foundation for giving consumers choices among providers and rates. In traditional markets, barriers to efficient rates include technology issues (e.g., metering costs), financial disincentives posed by traditional rate-making practices, regulatory concerns, and apparent lack of consumer interest.

Current market developments that appear to offer new opportunities for more efficient rates include:

- The advent of organized wholesale power markets that provide transparent hourly prices, which can be used as the basis for retail prices
- An improving business case for advanced metering infrastructure, and increasing deployment of such systems for all customers
- Expiration of rate freezes in retail access states, which provides new opportunities to offer efficient price structures that reflect wholesale market prices
- The requirements imposed by the Energy Policy Act of 2005 (EPAct 2005), which have renewed regulatory interest in advanced metering and efficient pricing

We identified several strategies (see below) that can help to overcome remaining barriers to efficient pricing that continue to exist even given the above developments.

Chapter 4, Conclusions, summarizes strategies identified to overcome barriers to efficient pricing, which include the following:

1. To overcome concerns about the potential under-recovery of fixed costs due to reduced consumption stimulated by time-based rates, implement some combination of (a) revenue adjustment mechanisms to track allowed revenue toward fixed costs, and (b) greater use of customer charges which are graduated to reduce disproportionate impacts on smaller customers
2. To overcome concerns about potential revenue losses from “adverse selection” of voluntary rates (i.e., the selection of time-differentiated rate options by customers whose peak-period consumption is below-

average for their rate class, so they save money even without changing consumption), allow adjustments to standard flat rates to cover the cost and risk of serving the remaining customers

3. To provide utilities with a financial incentive to offer voluntary time-based rates, allow any net revenue gains to be shared between customers and shareholders
4. To overcome customer resistance to the increased complexity and price risk of time-based rates; offer simple, fairly priced optional rates combined with standard rates that include appropriate risk premiums for guaranteed prices; market the rates effectively; and possibly combine them with communication and control technologies that facilitate consumers' response to varying prices
5. To further mitigate the financial disincentives to utilities to offering voluntary rates in the presence of class-wide standard rates, move toward greater refinement of rate classes to reduce the variability of within-class usage patterns, where the ultimate solution would be customized pricing for individual customers based on actual usage patterns measured with advanced metering equipment[1]

Some of the above strategies would require potentially difficult regulatory decisions that could cause a range of bill changes as existing within-class cross-subsidies are removed. These changes would increase rate fairness, as customers whose cost to serve is below average would no longer subsidize other customers. In addition, the more efficient rates that could be offered through these strategies should increase economic efficiency and reduce overall resource costs to all consumers.

[1] Individualized pricing is analogous, for example, to supermarkets' standard practice of "metering" the actual items in each consumer's cart and charging them for the cost of those items. In contrast, the hypothetical analog to traditional utility pricing would be to charge an average "price per shopping bag," based on an estimated average cost for the typical bag, without regard to the actual items in the bag.

1. INTRODUCTION AND BACKGROUND

Today's electric power industry faces a number of important challenges as it adapts to evolving wholesale and retail markets. Robust wholesale power markets now operate in key regions of the U.S., and retail markets have been restructured in many states, giving consumers varying degrees of access to competitive energy providers. Two important challenges brought on by these evolving market structures involve: 1) maintaining reliability and efficient operation of the existing power system, and 2) ensuring adequate generation, transmission, and distribution resources in the future. A related challenge posed by potential climate change initiatives will affect the operation of existing resources and investment in future resources.

Specific industry concerns include:

- Increasing fuel costs and volatility
- Pending removal of rate caps in several states
- Technological advances and cost reduction in advanced metering and communications equipment
- Potential for supply disruptions
- Potential restrictions or additional costs imposed by climate change actions
- A perceived need for greater price-responsive demand through an improved alignment of retail and wholesale electricity markets
- Requests for special rates for distributed energy resources and specific technologies
- An apparent desire by consumers for more pricing choices to better fit their needs

Retail electricity pricing and rate design play a central role in each of these areas.

1.1 Linking wholesale and retail markets

Industry experts increasingly recognize the importance of improving the link between wholesale and retail power markets, because of its potential for improving the efficiency of electric power system operations and resource investments. Currently the two sides of the electricity market are largely disjointed. On the supply side, wholesale power costs vary substantially over time and location, sometimes changing dramatically from one day to the next due to unexpected changes in demand or availability of generating units. At the same time, on the demand side, most consumers face fixed retail rates, and thus have no incentive to use electricity differently on high-cost days than on low-cost days. As a result, consumers' demand for electricity remains largely independent of conditions in the wholesale market, which leads to inefficient and wasteful use of, and investment in, generation and transmission resources.

If instead at least some customers faced retail prices that reflected wholesale market conditions, then the resulting price-responsive demand (PRD) would provide a shock-absorbing effect that would reduce cost and improve reliability. PRD load reductions effectively serve as virtual resource capacity. In the absence of price-responsive demand, a larger cushion of reserve capacity is needed to guarantee reliability of the power system. Investing in and maintaining this extra reserve capacity is costly, raising energy costs for all consumers.

A number of utilities and states have been testing a variety of efficient pricing designs, spurred on in part by EPAct 2005, by the improving business case for advanced metering equipment needed to support more efficient pricing, and by a recognized need to expand the amount of PRD.

Increasing the amount of PRD through more efficient retail prices is generally viewed as producing a number of potential benefits, including:

- Lower overall energy costs due to avoiding high generation costs
- Reduced need for peak generation capacity
- Potentially reduced greenhouse gas emissions due to more efficient resource use
- Reduced market power on the part of generators during periods of low reserve capacity
- Reduced wholesale price spikes
- Improved overall market efficiency

1.2 Features of traditional retail rate design

Retail electricity rates have traditionally been characterized by three fundamental properties. First, they have been set at the same level for broad classes of customers (e.g., all residential customers) whose usage patterns can vary widely. Second, retail rates are typically set at a fixed level that reflects the broad average of the hourly costs to serve customers in the class over a year or season. Third, traditional retail rates focus largely on recovering utilities' historical embedded costs rather than reflecting forward-looking market costs.

The resulting static, averaged retail rates under traditional designs give consumers inaccurate information about the actual resource cost of generating and delivering power. When wholesale costs rise above the fixed retail price, the lack of price-responsive demand causes higher resource costs to be incurred than would otherwise be needed. When wholesale costs fall below the fixed price, consumers forgo consumption that they otherwise might use productively at lower prices to expand economic activity.

In addition, charging the same one-size-fits-all average price to customers with different usage patterns means that the average cost to serve some customers is less than the price they pay, while the average cost to serve others is higher than the class-wide price. This existing cross-subsidy of high-cost customers by low-cost customers presents a transition barrier which complicates efforts to improve pricing efficiency.

1.3 Efficient pricing

In contrast to traditional retail rates, retail prices that reflect expectations of changing wholesale market costs are efficient prices. Wholesale market prices have proven to be characterized by two key features—considerable volatility from day to day and hour to hour; and uncertainty about future values. The combination of features implies potential risk to energy providers and consumers, depending on how the risk is managed and allocated. At the same time, consumers demonstrate diverse preferences, or tolerance for risk. Efficient pricing thus has three basic properties—it reflects time-varying wholesale prices, reflects the relevant risk to providers, and offers choices that reflect diverse consumer risk preferences.

In competitive markets, efficient prices generally evolve naturally. Suppliers offer a range of products, at different prices, to diverse consumers who choose the best product and price for their situation. However, retail electricity prices have remained largely regulated by the states, and the priority of efficient pricing has generally lagged behind other issues, such as agreeing on utilities' total revenue requirements and allocating those total costs across different customer groups. In addition, metering technology costs have presented a barrier to more widespread adoption of meters capable of recording consumers' usage on a timely basis, which is needed to support pricing which varies hourly or daily.

1.4 What's new about today's markets?

Many different types of efficient electricity pricing have been discussed, debated and tested over the past 30 years or more. However, the vast majority of customers continue to face a single inefficient, fixed rate, with few or no alternative choices. A number of factors have converged in recent years to provide new opportunities, new incentives, and an increase need for more efficient retail electricity prices (rates). These factors include:

- Organized wholesale markets covering large regions of the U.S., which are providing transparent hourly prices
- Declining generating reserve margins and increasingly volatile wholesale market prices, which are focusing attention on the need for increased price-responsive demand
- Increasing deployments of advanced metering infrastructures (AMI), stimulated by declining AMI cost, and the "smart" metering standard in EPAct 2005

Electricity is an increasingly critical infrastructure for the post-industrial, information-based U.S. economy. Retail electricity revenues totaled nearly $300 billion in 2005.[2] Estimates of the potential benefits from increasing price-responsive demand vary widely.[3] Based on a number of analyses of time-of-use and real-time pricing programs, we estimate that economic efficiency could be improved by approximately 0.5 to 2 percent, which implies annual resource cost savings and enhanced consumer value of $3 billion to $6 billion.

1.5 Organization of the report

This monograph provides an overview of efficient electricity pricing in the context of evolving markets. Section 2 provides a framework for efficient electricity pricing, discussing the nature of electricity costs, and categories and examples of efficient pricing that enable prices that reflect those costs. Section 3 first describes how efficient pricing is implemented in retail access markets, then reviews barriers to efficient pricing in traditional markets and proposes strategies for overcoming those barriers. Section 4 offers conclusions.

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2 Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report."

3 See "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them," U.S. DOE report to U.S. Congress, February 2006.

2. FRAMEWORK FOR EFFICIENT ELECTRICITY PRICING

Efficient pricing has always been recognized as one of the fundamental principles of sound electric utility ratemaking, which have traditionally included the following:

- Fairness
  - to customers, in allocating costs of service across customer classes and minimizing cross-subsidies between groups of customers, and
  - to utilities and their shareholders, in recovering prudently incurred costs
- Efficiency—minimizing resource costs to achieve a given level of energy services, while ensuring the level of reliability desired by customers.[4]

However, efficient pricing has generally taken a back seat to the cost recovery and cost allocation objectives of electricity ratemaking.

Dr. Alfred Kahn, who once served as Chairman of the New York Public Service Commission, explained the fundamental rationale for setting efficient retail prices so as to signal marginal cost, which is to achieve an efficient allocation of society's limited resources.

> *At any given time, every economy has a fixed bundle of productive resources, a finite total potential productive capacity. Of course, that total can grow over time; but at any given time the basic economic problem is to make the best or most efficient use of that limited capacity. The basic economic problem, in short, is the problem of choice. A decision to produce more of any one good or service is, in these circumstances, ipso facto a decision to produce less of all other goods and services taken as a bunch. It follows that the cost to society of producing anything consist, really, in the other things that must be sacrificed in order to produce it; in the last analysis, "cost" is opportunity cost—the alternatives that must be foregone. In our economy, we leave the final decision about what shall be produced and what not to the voluntary decisions of purchasers, guided by prices on the one hand and their own wants or preferences on the other.*[5]

Understanding the nature of efficient electricity pricing first requires an appreciation for the nature of electricity costs.

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[4] Bonbright, Danielsen, and Kamerschen [1988] provide a comprehensive discussion of rate-making principles.

[5] Kahn [1988].

2.1 Electricity costs

The total cost of generating and delivering electricity to consumers may be separated into the following four fundamental categories of basic services:

- Customer services, which primarily involve communication with customers (as through billing). The costs of these services generally depend upon the number of customers and the passage of time (e.g., billing each month), and do not vary with customers' energy consumption.
- Distribution services, which are services associated with distribution facilities. In any subsystem of the distribution system, these costs depend on the number, location, and density of customers, and on-peak loads, which determine the sizing of certain distribution facilities.
- Transmission services, which are services associated with transmission facilities. The costs of these services may be divided into two broad categories: transmission facility-related costs and generation-related costs, which arise because of transmission losses and transmission constraints and are related to the locations of generators and loads.
- Generation services, which are the provision of electrical energy and ancillary services, such as regulation, operating reserves, reactive power, and blackstart. The costs of these services are related to customers' loads and locations.

Integrated utilities in regulated states must set rates to cover their costs for all of the above services. In states with restructured retail markets, distribution utilities set regulated rates to cover their customer and distribution services costs. In addition, regulators set default or provider-of-last-resort (POLR) rates to cover the cost of generation services for those customers that elect not to take service from a competitive provider. Competitive energy providers set prices that will cover their cost of providing generation services and which they believe will be attractive to consumers. Transmission facilities charges are also passed on to customers by their energy provider.

2.1.1 Marginal costs of generation services

The costs of providing customer, distribution, and transmission facilities services are largely fixed. However, the marginal costs of providing generation services vary substantially over time and locations. "Marginal costs" are defined as the changes in power system costs that are caused by a small (e.g., 1 MW) change in demand (or "load"). Marginal costs change over time because electricity is essentially non-storable and because loads change from hour to hour, and indeed, from minute to minute, so different generators with different fuel costs will be the marginal power source at different times. Marginal costs change by location because transmission losses and constraints make it more costly to deliver power to some locations than to other locations.

In principle, the marginal costs associated with changes in load levels are composed of two broad categories of costs. First is marginal energy costs (also called "marginal operating costs"), which are primarily the marginal fuel and labor costs of generating power. Second is marginal outage costs (also called "marginal reliability costs" or "marginal capacity costs"), which are the expected costs of the risk that a load increase will increase the chance of a generation-related power shortage. Marginal outage costs measure the reliability benefit, if any, that is due to a load reduction.[6]

Historically, the concept of efficient pricing has focused largely on utilities' internal marginal generation costs. In recent years, regional wholesale energy markets have been developed in which both regulated and independent generators bid their output into day-ahead and/or real-time energy and reserve markets, and are selected in order of their bids. In these markets, wholesale energy prices have emerged as transparent reflections of the hourly marginal costs of providing generation services.[7] Since consumers' usage decisions reflect their tradeoff between the value that they receive from electricity and the price they have to pay, efficient retail prices serve the role of matching customer value and resource costs. This condition ensures that society's resource costs are minimized while achieving consumers' greatest net value.

2.1.2 Wholesale market prices

In organized wholesale markets, market-clearing energy prices generally approximate marginal energy costs. During periods of relative shortage of generating capacity, they can also rise to levels that reflect marginal outage costs in addition to energy costs. For example, depending on the price of natural gas and the efficiency of peaking generation units, the highest wholesale price due to marginal operating costs might be in the range of $150 – $200/MWh. However, as shown in Figure 2.1 on Page 8, wholesale energy prices on occasion rise far above that level to reflect the marginal cost of maintaining reliability, or avoiding outages.[8]

2.2 Opportunities for improving economic efficiency

Retail rates that are fixed at one level frequently differ substantially from varying hourly wholesale energy market prices. These differences between cost and price suggest extensive foregone opportunities for improvements in economic efficiency, including reductions in resource costs. To illustrate these opportunities, Figure 2.1 shows two distributions of hourly wholesale energy prices for the PJM East region—one for Summer 1999 and one for Summer 2000—with hourly prices arrayed from high to low. Also shown is a horizontal line which represents an energy provider's expected cost to serve the total loads in the region, given the two distributions shown, including a risk premium to cover price and load uncertainty. This amount could serve as the basis for a flat seasonal retail energy price.

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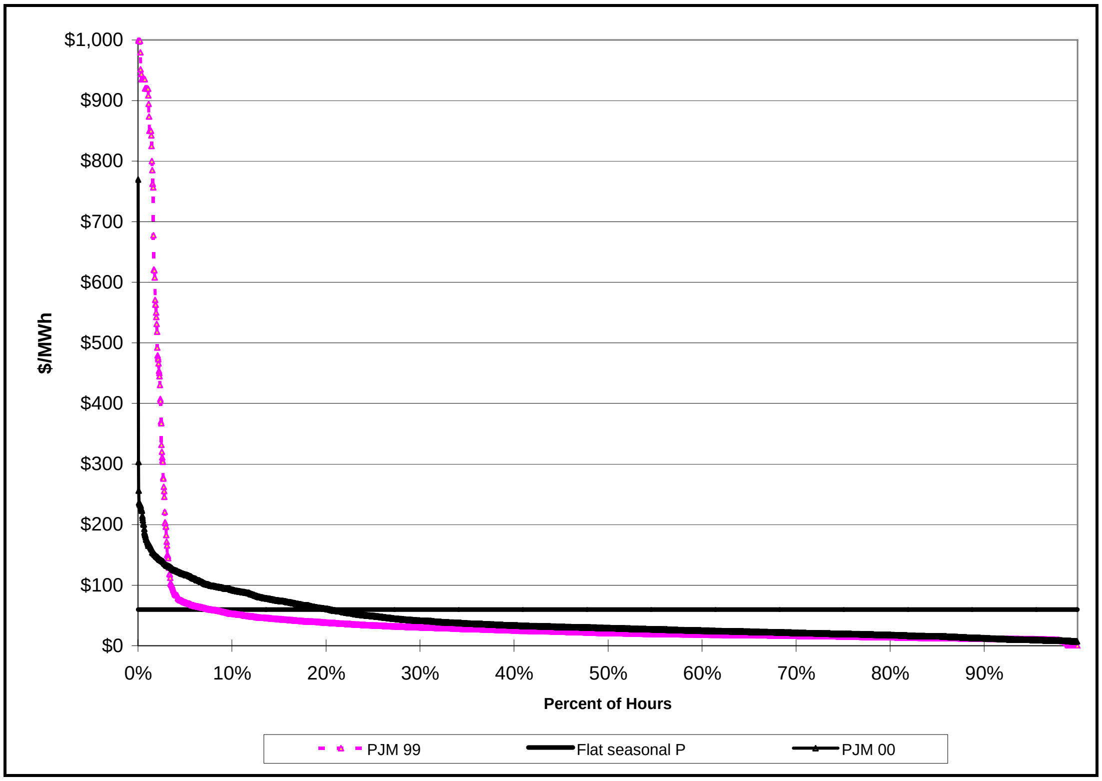
[6] A third category of marginal costs is marginal externality costs, which are costs imposed upon parties other than electric power market participants. Prominent among these costs are environmental and national security costs. Some of these costs have been "internalized" through utility investments required by various clean air and water requirements, and are already reflected in wholesale prices. Whether to include others, such as costs associated with carbon dioxide emissions, is a public policy decision.

[7] It should be noted that while the principle of electricity marginal costs has been known for some time, the actual marginal costs of electricity supply, which change frequently, are not easily observable. In fact, the estimation of location-based marginal prices (LMP) for multiple points in the region covered by a wholesale market is an enormously complex task, requiring specialized computer software and the collection of vast amounts of data on power system conditions at numerous locations. The ability to calculate LMPs in the time frame needed to operate day-ahead and real-time energy markets has only become available in the past decade.

[8] Several wholesale markets have capped energy prices at $1,000/MWh. However, energy prices have reportedly risen to levels in excess of $6,000/MWh on a few occasions in uncapped markets.

Figure 2.1 Distributions of wholesale energy prices PJM East – Summer 1999 and 2000



The two price distributions illustrate certain typical and important features of hourly wholesale energy costs. First, the distribution of prices is highly skewed, with prices taking on values of less than half of the average price in approximately 30 percent of the hours, remaining below the average price in 75 to 90 percent of the hours (depending on the year), and reaching relatively high levels only in the top 1 to 3 percent or so of hours. Second, conditions can vary widely from year to year, with a number of extremely high prices in one year and none the next. Finally, the highest prices often exceed the lowest prices by a factor of 10 or more.

This figure clearly demonstrates the disconnection between varying wholesale energy costs and fixed retail prices that prevails in most electricity markets today, and which represents a lost opportunity for significant gains in efficiency. For example, in an important but relatively small number of hours, the marginal cost of producing electricity far exceeds the incremental value that customers receive from consuming it, as reflected in the fixed price they willingly pay. If instead at least some customers faced retail prices that reflected those high market costs, and reduced their usage during these hours, the resulting avoided resource costs would far exceed customers' voluntarily foregone value of power. In addition, fixed retail prices give consumers no access to the relatively low-cost power that is available in a large fraction of all hours. If consumers had access to those low prices and responded by increasing usage during these periods, then they would experience additional value that would exceed the resource cost of generating that power.[9] In this era of global competition, lower energy costs can be critical to the economic viability and livelihood of many industries.

[9] Appendix A provides a formal discussion of the sources of gains in economic efficiency from such usage changes.

2.3 Properties of efficient pricing

As illustrated above, wholesale market prices have proven to be characterized by two key features—considerable variability from day to day and hour to hour; and uncertainty about future values. Both have implications for the design of efficient retail prices.

2.3.1 Efficient prices reflect time-varying costs

The time-varying nature of wholesale energy costs suggests that efficient retail prices should also vary by time. Since prices can vary by time in a number of different ways, a wide range of pricing strategies is possible for reflecting wholesale costs to varying degrees of accuracy. These may range, for example, from hourly real-time prices that reflect hourly variations in marginal costs nearly exactly, to seasonal flat prices that reflect seasonal differences in the average of expected hourly marginal costs over several months. Since the variability of marginal costs tends to be greatest in a relatively small fraction of hours in a year, as shown in Figure 2.1, rate structures whose prices are fixed most of the time, but are allowed to vary under certain cost conditions, may capture a relatively large portion of the economic efficiency benefits available from moving away from flat average pricing.

2.3.2 Efficient prices reflect the relevant risk to energy providers

Offering retail prices that reflect expected time-varying wholesale price patterns, but which are fixed over certain time periods, involves some degree of risk to energy providers due to the inherent uncertainty regarding actual future wholesale costs. For example, a retail energy provider may offer a flat price based on an expectation that wholesale prices over the next year will average $50/MWh (or $0.05/kWh). However, depending on a variety of factors, including fuel costs, weather conditions, and consumers' usage patterns, the provider's actual wholesale costs might average $45/MWh or $55/MWh.[10] Thus, fixed retail energy prices of all types necessarily include a risk premium whose magnitude depends on the nature of the price structure (e.g., the premium is larger for prices that are fixed for longer time periods). The nature of the risk premium also depends on the structure of the retail market, a matter to be discussed in Section 3.

2.3.3 Efficient prices acknowledge diverse consumer risk preferences

The mirror image of the risk to energy providers from offering retail prices whose values are fixed over certain time periods is that consumers face risk from retail prices that vary over time. Efficient pricing recognizes that consumers vary in their preferences regarding the risk associated with prices that vary (i.e., price risk). Some customers are more willing than others to take on energy price risk in order to obtain lower expected electricity prices (i.e., through smaller risk premiums). Others are willing to pay a substantial premium to avoid as much risk as possible from price volatility.

[10] Retail energy providers typically hedge their price risk by owning generation capacity or entering forward contracts for blocks of power at fixed prices. However, forward contract prices build in market participants' risk perceptions, and owning generation entails its own financial risk.

Traditional "one-size-fits-all" retail rates impose the same inherent risk premium on all consumers in the rate class. In principle, the premium for such service is relatively high due to the long-term fixed price commitment made by the utility.[11] By contrast, efficient pricing allows a range of retail price structures which allow customers to trade off cost minimization vs. protection from peak wholesale prices. Efficient pricing, given diverse customer needs and preferences, implies an efficient portfolio of optional price structures, where each price structure is based upon a combination of expected wholesale market prices and sound risk fundamentals.

2.4 Categories of efficient time-based pricing

This section describes a range of categories of efficient time-based price/rate structures. As suggested by the foregoing discussion, these rates vary by the degree of price risk passed on to consumers, and thus by the amount of risk premium that is built into the prices by energy providers. The categories range from rate structures in which prices vary on an hourly, daily, or longer time-period basis. Specific examples from each category are introduced, including a brief description, principles for setting the prices, and examples of implemented versions of the price structures, where available. Section 3 then discusses strategies for implementing efficient pricing in traditional and retail access markets.

2.4.1 Hourly pricing

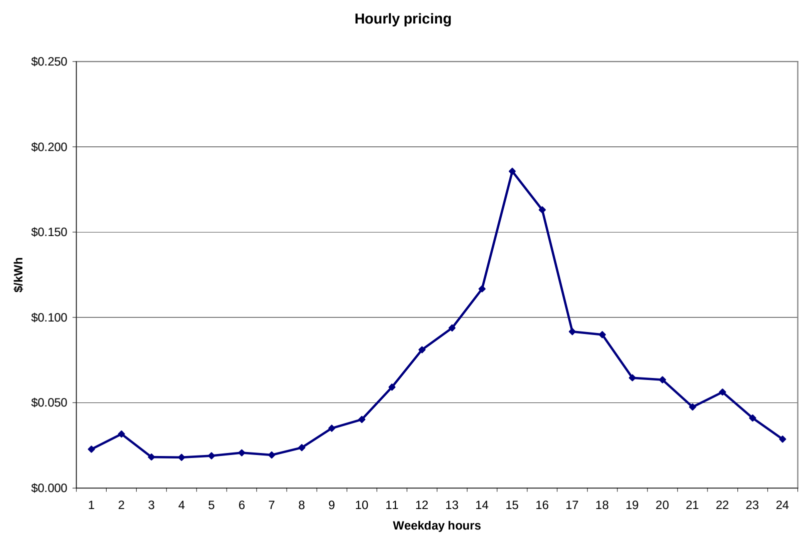
In these price structures, retail energy prices to consumers vary hourly to reflect changes in wholesale energy prices or regulated utilities' internal system marginal costs. Prices are typically announced a day ahead or an hour ahead, though in some cases they can be based on real-time market-clearing prices. In traditional markets, particularly those that lie outside of the footprint of an organized wholesale market, the hourly prices are often based on a utility's calculation of its marginal generation costs, including marginal reliability, or capacity costs when warranted by reserve conditions. In retail access markets, the most straightforward form of hourly pricing involves a simple indexing or pass-through of wholesale market prices with a small retail markup. Because of the variability of marginal costs and wholesale energy prices, hourly pricing is often offered in conjunction with financial contracts through which customers manage their risk of price uncertainty through guaranteed fixed prices on some fixed portion of their load. The following examples illustrate several versions of hourly pricing. They are distinguished largely by the methods of hedging price risk and/or guaranteeing revenue stability, which tend to differ in retail access and traditional markets:

1. **Basic hourly pricing**. Basic hourly pricing represents the direct pass-through of hourly wholesale energy prices (with little or no markup) to retail consumers. Most examples of basic hourly pricing are found in retail access markets. For example, competitive providers offer hourly indexed pricing to some large customers who are interested in the lowest possible price, with no risk premium, and are willing to take on the risk of varying prices that are indexed to wholesale market prices. Second, some states with restructured retail markets have mandated hourly pricing as the default rate for generation services for customers above a certain size. This requirement has the combined features of: 1) relieving distribution utilities of the requirement to take on and charge for managing price risk, 2) providing customers with an incentive to choose a competitive provider who offers such risk management through various fixed and variable-price offerings, and 3) providing incentives for customers who remain on the default rate to

[11] The degree of risk borne by the utility varies, depending on whether it owns its own generating assets, and the terms and duration of its fuel and power supply arrangements. In addition, regulated utilities' risk is often reduced through practices such as fuel adjustment mechanisms and frequent rate cases. Thus, regulated fixed rates may not in fact carry risk premiums of the type employed by competitive retail providers, but instead pass the risk of unexpected cost increases onto customers.

respond to hourly prices. Finally, one utility, Commonwealth Edison, has offered a pilot hourly pricing rate to residential customers in Chicago through a community agency.[12] Figure 2.2 illustrates a prototypical profile of hourly prices on a summer weekday.

Figure 2.2 Hourly pricing

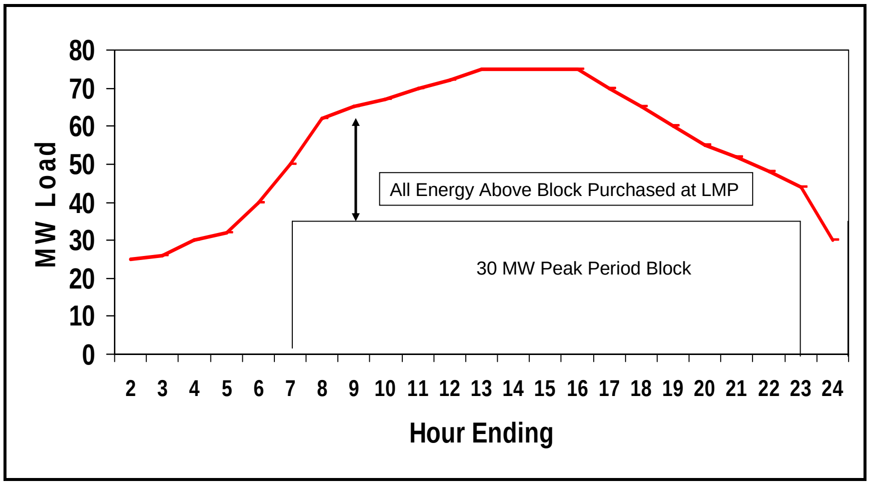


2. **Block and index pricing offered by competitive retail providers**. In these combined contracts, customers pay hourly prices indexed to the relevant wholesale energy market (e.g., PJM, NYISO, ISO-NE, ERCOT), but enter a forward contract at a fixed price for a fixed block of load, typically for a wide peak period, which operates as a financial contract for differences. The combined contract acts to ensure that customers effectively pay no more than the fixed price for the fixed block of power, regardless of the level of the hourly indexed prices. They pay hourly prices for usage in excess of the contract block loads, and are credited at hourly prices for load reductions below the contract level. Prices for fixed blocks of power carry a smaller risk premium than the alternative of open-ended fixed prices since they remove quantity risk to the energy provider and may be linked to available forward contract prices in the wholesale market. Block and index pricing is illustrated in Figure 2.3. *(See next page.)*

   Examples of this price structure are products offered by Constellation New Energy, Pepco Energy Services, and other retail providers in restructured markets with retail competition. It appears that current forms of this price structure are relatively inflexible, in that the blocks of power that may be purchased are typically quite broad, corresponding to typical wholesale market trading products. These blocks may be satisfactory for large industrial customers whose load profiles are relatively flat, or customers that are comfortable with a relatively low block compared to their typical peak usage level. As markets develop, some providers may offer narrower customized blocks that are priced so that consumers with a more distinct load profile may "stack" blocks of different lengths to make them correspond more closely to their typical load profile.

[12] All major utilities in Illinois are required as of January 1, 2007 to offer residential real-time pricing.

Figure 2.3 Block and index pricing



3. **Two-part RTP at regulated utilities.** The form of hourly pricing most common in traditional markets is usually referred to as two-part RTP, in reference to the two linked tariff contracts that characterize the product. Under this price structure, which applies to bundled service, customers' total bills are composed of two parts: 1) a base bill that is calculated by applying their standard tariff to a fixed customer baseline load (CBL) that represents their historical usage profile (typically for the year prior to joining RTP), and 2) hourly prices applied to differences between their actual and CBL usage (i.e., they pay RTP prices for usage in excess of their CBL, and are credited at RTP prices for load reductions below their CBL).[13] Examples of two-part RTP programs are those offered by Georgia Power Company, Duke Power Company, Progress Energy, and others. Two-part RTP can be viewed as a mechanism for regulated utilities to transition to efficient pricing, while maintaining the recovery of embedded revenue requirements allowed by standard tariffs. For example, revenue recovery is addressed by the portion of the two-part contract by which RTP customers pay their standard tariff for their historically based CBL. This means that the utility will receive essentially the same revenue from each customer under RTP that it would have received had the customer remained on the standard tariff and consumed at his historical level.[14] This provision reduces utility and regulatory concerns about differential customer bill impacts, since each RTP customer's base bill remains at its historical level. The second portion of the contract, in which consumers pay hourly prices for usage in addition to their CBL and receive credits for usage reductions below their CBL, provides economic incentives to customers to respond to hourly price changes. These changes in consumption patterns can potentially provide economic benefits to both RTP customers and the utility (see Appendix A), thus providing incentives for the utility to offer the rate and

[13] The total bill under two-part RTP may be characterized equivalently as the bill for total usage in each hour at hourly RTP prices, plus a series of hourly financial adjustments that are based on the differences between the hourly prices and the fixed standard tariff rates for the amount of the CBL in each hour (e.g., for each kWh in the CBL, the customer pays an amount equal to the difference between the standard tariff and hourly price during low-price hours, and receives a credit equal to the difference between the hourly price and standard tariff rate during high-price hours).

[14] Alternatives to two-part RTP for collecting regulated utilities' revenue requirements have included a variety of one-part RTP designs, in which hourly wholesale energy prices are marked up by an amount estimated to be needed to recover the additional class-wide revenue requirements. However, these program designs have generally proven unpopular with customers due to the potentially large price markup and the risk of price uncertainty, and unsuccessful for utilities because of revenue attrition due to participation largely by customers with favorable load profiles who achieve bill reductions without having to respond to prices.

customers to participate. While two-part RTP provides efficient hourly price signals to participating customers about the marginal cost of energy, it does not address any existing inefficiencies or inequities (e.g., within-class cross-subsidies) that may be present in the standard class-wide tariff. The primary differences between two-part RTP in traditional markets, and block and index pricing in retail access markets, are that the CBLs under two-part RTP are normally set by the utility to reflect the customers' usage patterns, and the rate applied to the CBL is the standard bundled tariff rate, rather than a market-based price reflecting forward energy prices in the wholesale market. The following price structure offers a way to narrow these differences.

4. **Unbundled RTP with self-selected baseline load**. Since it is largely the costs of generation services that vary hourly, it is logical that hourly RTP prices in traditional markets be designed to recover only those costs, with other tariff components used to recover transmission and distribution facilities costs. This condition suggests a form of RTP in traditional markets that is analogous to the block and index products offered in competitive retail markets. That is, utilities could unbundle their costs and tariffs into components for distribution and transmission facilities services, and for generation services, and apply hourly pricing only to the generation services portion of RTP customers' bills.[15] For example, the rate for T & D services could remain some combination of demand and energy charges applied to the customer's actual consumption. For generation services, the customer would face hourly prices tied to wholesale market costs or utilities' estimated marginal cost for energy and reliability. Risk management would be provided through a CfD (see Appendix A) at a fixed contract price (based on forward market prices or the utility's estimate of expected prices in a future year) for fixed blocks of load, as with block and index pricing. Importantly, the amount of the fixed block could be selected by consumers based on their risk preferences, rather than established by the utility at historical levels.[16] Given the selected fixed blocks, the unbundled RTP product would operate the same as the block and index product in competitive markets or two-part RTP in traditional markets in terms of providing customers with an incentive to respond to hourly prices, while at the same time protecting them against price risk. Georgia Power offers a limited version of this price structure as a "price protection product" for its two-part RTP customers whose usage has expanded beyond their historical CBL, and who wish to reduce their risk of price uncertainty on their exposed load. This price structure also addresses a concern that has been expressed about the fixed-CBL feature of two-part RTP, in which the CBL is established permanently at the time that a customer selects RTP. If the customer's usage expands beyond the CBL in future years, then that consumption is billed at RTP energy prices alone. Some concern has been expressed that utilities will under-recover incremental distribution services costs that may arise due to that growth in usage, and thus require cost recovery from other consumers.[17]

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[15] All utilities in retail access states have unbundled their tariffs to separate generation services from other services. Some utilities in traditional markets have also unbundled their costs and tariffs.

[16] Note that the reason for basing the CBL on customers' historical usage under two-part RTP is to recover from each RTP customer essentially the same amount of revenue toward allowed T & D and generation costs as under the standard tariff, before any changes in revenue caused by customers' response to RTP prices. Under unbundled RTP, the utility would generally receive the same revenue from RTP customers toward T & D costs as they would if the customers remained on the standard tariff. Thus, so long as the utility's generation revenue requirements are reasonably consistent with expected wholesale market costs, the utility should be indifferent to whether the customer opts to set a high or low CBL. Only if the utility's allowed revenues to cover generation costs are substantially *higher* than expected wholesale market prices (due to high historically incurred generation costs), or *lower* than expected wholesale market prices (due to heavily depreciated generation assets) will the utility and the customer want to have a CBL that differs from historical usage patterns. In these cases, a fixed adjustment to the consumer's bill could be made using an historical CBL for the amount of the difference between allowed revenues toward generation costs and expected market prices.

[17] Georgia Power Company's RTP tariff has a provision for direct recovery of distribution system costs that are unambiguously caused by expansion of an existing RTP customer's facility.

The hourly prices in all of the above rate structures give consumers incentives to respond to prices that directly reflect wholesale market conditions. The lack of price guarantees implies no need for risk premiums, and therefore the lowest expected cost of power. Furthermore, the various types of financial hedging arrangements give consumers the opportunity to protect themselves against unexpected price variability, which might otherwise make them unwilling to accept hourly pricing.

2.4.2 Daily pricing

In these structures, prices are fixed across blocks of time, but the price for at least one of the blocks (or certain hours within the block) has the potential to vary daily, either on a regular or occasional basis. The varying price may be announced on a day-ahead or hour-ahead basis. Examples of daily pricing are the following:

1. **Day-type time-of-use rate**. Under this rate structure, multiple TOU price profiles (e.g., low, medium, and high) are established in advance to reflect expected wholesale prices by time period on different price day-types. The applicable price profile is announced a day ahead of time. An example is the Tempo residential tariff offered by Electricité de France, which consists of three TOU price profiles, with limits on the number of times that the medium and high prices may be called.
2. **Variable peak rate**. A fixed off-peak price is established, but the on-peak price is determined on a daily basis to reflect energy market prices, and is announced a day ahead of time. This price structure may be thought of as a simplified version of hourly pricing, in which hourly prices are averaged into pricing periods. It has been proposed by ISO-NE for application as a default rate for large customers in Connecticut.
3. **Critical peak pricing (CPP).** One of the price structures of most active recent interest for mass-market customers, this price structure typically consists of a base TOU rate plus a pre-specified critical price that is considerably higher than the TOU peak price. When combined with CPP, the corresponding TOU peak price can be offered at a discount relative to a standard TOU rate, because the peak price does not have to cover the expected cost of the highest-cost hours. The utility can announce a critical day on a day-ahead or same-day basis, in which case the critical price applies during all or part of the peak period instead of the normal TOU price. The rate typically contains a restriction on the number of times that the critical price may be called. Gulf Power Company in Florida offers a permanent CPP/TOU rate through its GoodCents Select program. Several CPP pilots have been completed or are underway in various states, including California, Idaho, Colorado, Missouri, New Jersey, and Washington, DC. Two possible variations on the CPP/TOU design are suggested in the following examples.
4. **Variable CPP**. In this variation on CPP, multiple critical prices are pre-established (analogous to the day-type TOU rate), with the appropriate price announced that best corresponds to actual market conditions on the critical day. This design would address two practical issues in implementing a CPP rate, which are setting the critical price level and establishing the criteria to be used for calling a critical event. That is, if a single CPP price is set very high, then it may send an accurate price signal on rare, very high-cost days that may not occur in every year (see Figure 2.1). The utility will have little incentive to call it on a moderately high-cost day on which costs are lower than the critical price, but some load response would still be valuable. In contrast, if a single CPP price is set at a moderate level, then it may send a reasonably accurate price signal on the high-cost days in most years, but will be too low on the rare but important days when demand response is most valuable. Multiple critical prices would make the rate appropriate under a wider range of conditions. Figure 2.4 illustrates the features of a variable CPP/TOU rate. A standard CPP/TOU rate would have the same form, except with only one critical price value.

5. **CPP linked to a standard tariff**. In this variation, the critical price feature is simply added to a standard non-TOU rate. This design would offer the benefit of not having to first design and offer a new TOU rate in conjunction with the critical price option. This can help address potential bill impact and revenue erosion problems that can arise from voluntary TOU rates (see Section 3.2), and may simplify the option for consumers. Like CPP/TOU, the critical price, or prices, which would apply during a pre-determined peak period, could be announced on a limited number of days, and would depend on wholesale market conditions. Also like CPP/TOU, the standard tariff price would be discounted to account for the fact that it does not have to cover the cost of the highest-cost hours, as well as to provide an incentive for consumers to choose the rate.

6. **Peak-day rebate.** This pricing concept operates similarly to CPP linked to a standard tariff, although it also has features more commonly associated with a demand response program than a pure retail price structure. Under this design, the choice of facing and responding to a given critical event is voluntary. That is, customers remain on their standard tariff, even during critical events, but have the opportunity to receive a rebate payment for any load reductions below an estimated baseline load level designed to reflect their typical usage pattern. The economic incentive to reduce load in response to either the CPP price or peak-day rebate is essentially equivalent. However, the different features may affect consumers' likelihood of selecting each option.[18] This type of program has been tested in a pilot program by Anaheim Public Utility in California.[19] It is somewhat analogous to the buy-back, or split-the-savings, programs that some Midwest utilities offered to their largest customers in the late 1990s during periods of high wholesale market costs, and to current ISO-sponsored demand response programs. A potential advantage of this approach is that customers' participation and load response is voluntary. This may appear more attractive to customers than a TOU/CPP plan whose prices differ considerably from their existing rate, leading to uncertainty about bill impacts. A potential disadvantage relative to a straightforward retail price structure is that a baseline load level must be calculated for each customer for each occurrence of a critical event. This implies the need for additional resources, as well as the potential for gaming (e.g., some methods for calculating baseline loads may allow customers to modify their usage in ways that result in higher rebate payments) and free-riders (e.g., baseline load calculations may allow some customers to receive payment for apparent load reductions that they would have made regardless of the critical event).

[18] Letzler [2006] discusses psychological aspects of consumers' potential perceptions of the relative risk and reward of the alternative products.

[19] See Wolak [2006].

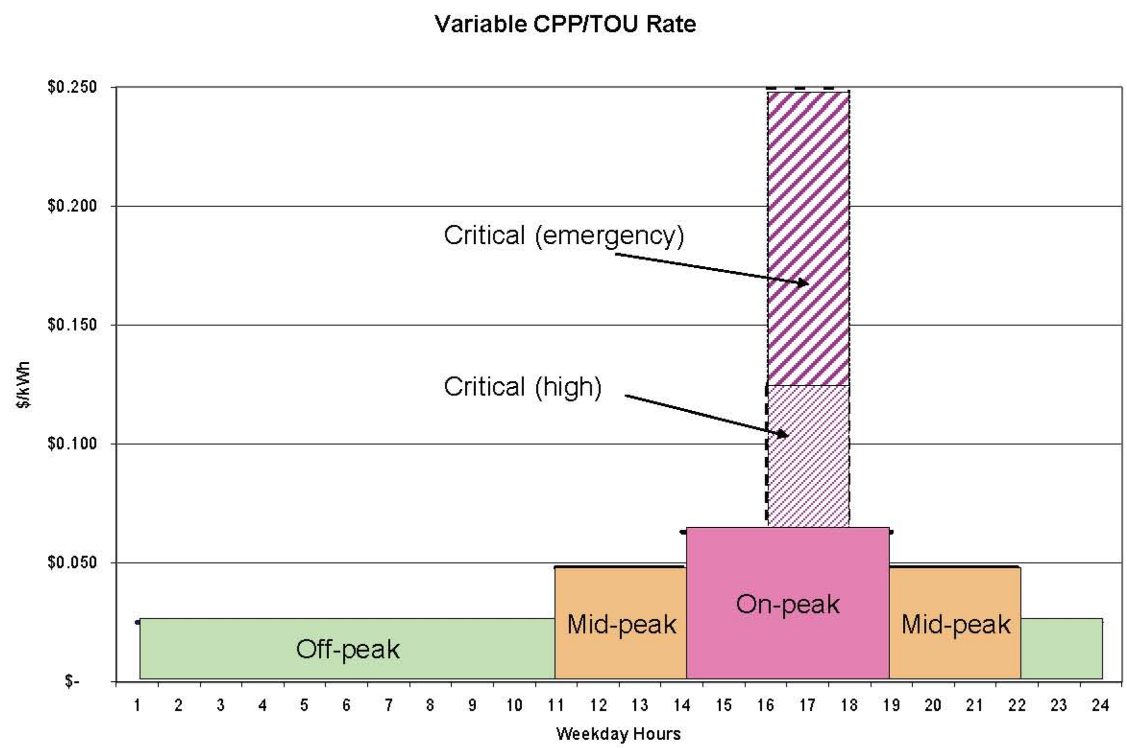
Figure 2.4 Variable CPP rate

Summer hours and prices:

	Hours ending	Price ($/kWh)	
On-peak	14 - 19	$	0.063
Mid-peak	11 - 13; 20 - 22	$	0.048
Off-peak	1 - 10; 23 - 24; and all weekend	$	0.025
Critical	(see below)		
High		$	0.125
Emergency		$	0.250

Critical events:

- Events may last from 1 to 6 hours during On-peak period
    - Critical (high) announced by 4 p.m. of previous day
    - Critical (emergency) events announced with 1 – 2 hours notice
- No more than 15 events per season
- No more than 30 emergency hours



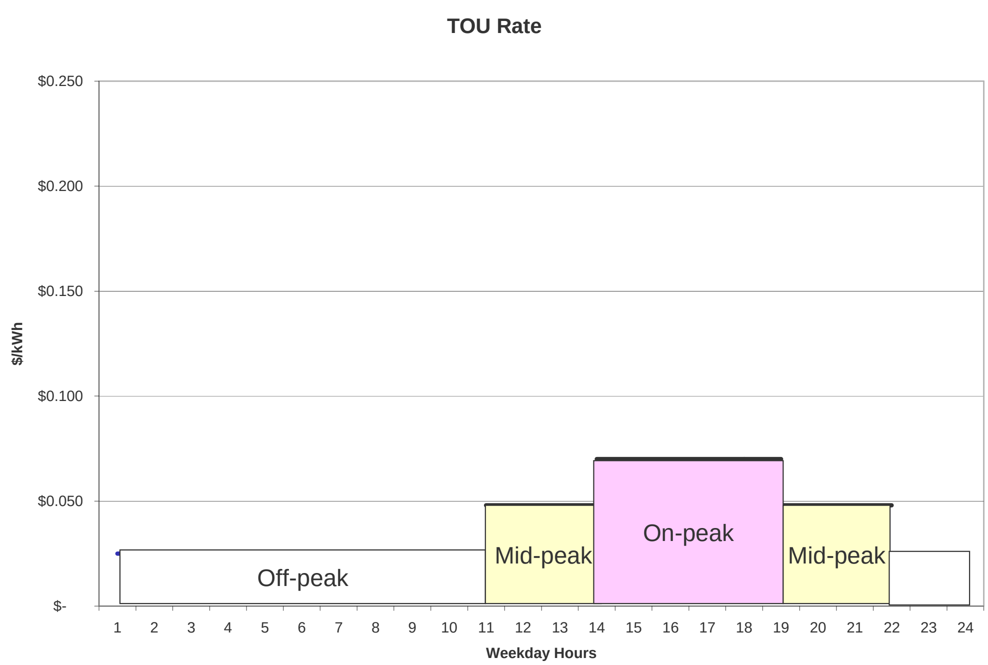
2.4.3 *Fixed time-of-use pricing*

In this price structure, prices are fixed within each TOU pricing period. Pricing periods may be defined according to time of day (e.g., on-peak, mid-peak, and off-peak), day of week (e.g., weekday and weekend), and/or season. Demand charges as well as energy prices may vary by time of day. TOU rates represent one of the oldest forms of efficient time-based pricing in the industry, and are relatively common as standard tariffs at many utilities for large commercial and industrial customers. Because TOU rates are fixed and announced months in advance, they signal customers about general differences in costs by time period. TOU rates provide an incentive for customers to shift load from peak to off-peak periods. (Appendix A illustrates how TOU customers can benefit from modifying usage in both peak and off-peak periods.) However, they do not provide incentives to respond differently to actual power system conditions as they evolve in the short term, such as on a day of unusually high wholesale costs. Furthermore, standard TOU rates at many utilities are not necessarily designed efficiently to reflect forward-looking marginal costs, but rather historical embedded costs. Figure 2.5 illustrates a set of hypothetical TOU energy prices under the same conditions that underlie the Variable CPP/TOU rate shown above. Note that the prices shown are illustrative of the cost of generation services only. The complete tariff would also include a charge for distribution services, which for residential customers might be on the order of $0.02/kWh.

Figure 2.5 TOU rate

Summer hours and prices:

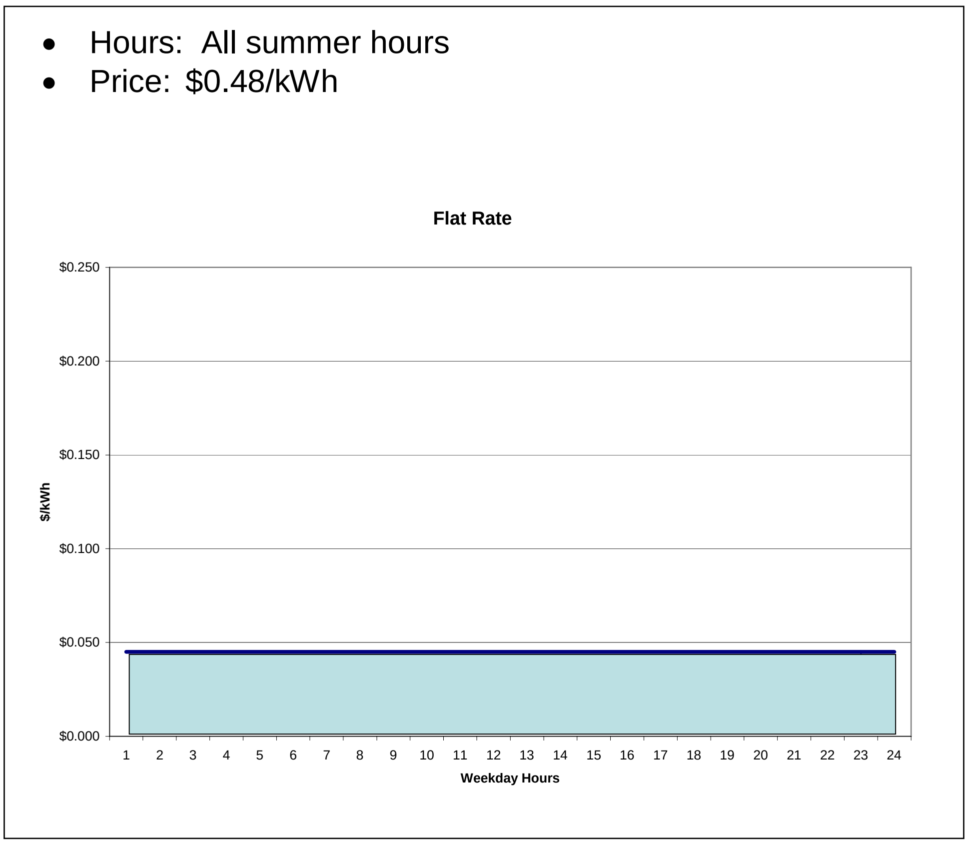
	Hours ending	**Price ($/kWh)**
On-peak	14 - 19	$ 0.070
Mid-peak	11 - 13; 20 - 22	$ 0.048
Off-peak	1 - 10; 23 - 24; and all weekend	$ 0.025



2.4.4 Seasonal flat pricing

In this structure, prices are fixed within a season (e.g., summer, non-summer) but may vary between seasons. The prices represent average differences between power costs in the designated seasons. Because they are announced months in advance, they provide customers with signals regarding differences in expected power system costs by season, and may thus provide weak incentives about, for example, the cost of air conditioning or space heating. However, they do not signal changes in actual power system conditions as they evolve in the short term. Figure 2.6 illustrates a flat seasonal price under the same conditions underlying the TOU and Variable CPP/TOU rates shown above.

Figure 2.6 Flat seasonal rate



2.5 Other forms of efficient pricing

The frequent differences between varying wholesale costs and fixed retail prices also create conditions that appear to call for specific pricing practices targeted to certain technologies or situations. Examples of these are discussed in this section. As we will see, most of these situations involve potential uneconomic behavior or investments that are driven by existing inefficient retail rates. In most cases, the use of efficient pricing has the potential to resolve the issue and provide incentives for economic behavior and investment.

2.5.1 Electric vehicle charging rates

The acceptance of electric vehicles (EVs) may well depend in part on the existence and design of relatively low electricity rates which make the cost of charging the vehicles competitive with the cost of standard and hybrid alternatives. Traditional retail rates that reflect average costs over all time periods are too high to meet this objective. Providing arbitrary discounted prices that are low enough to support EVs would be inefficient if they were less than the actual cost of electricity generation, and would be unfair to other customers who would have to subsidize them. However, as illustrated in Figure 2.1, generation costs are actually much lower than average in many hours of the year, particularly in overnight hours. Thus, attractive and efficient EV charging rates may be set by either limiting charging time to off-peak hours, by contract or control technologies, and setting efficient retail prices for that time period which reflect the typically low wholesale market costs during that period, or offering an efficient TOU rate.

2.5.2 Rates related to distributed generation

Distributed generation (DG) generally refers to power generation technologies that are owned by consumers rather than by utilities or other energy suppliers. These technologies range from large generators owned by large industrial customers to small units owned by individual residential customers (e.g., solar power units that sometimes generate more electricity than needed by the household). Distributed generation raises a number of pricing-related issues for utilities and regulators, including the following:

Incentives for economic DG. Fixed retail prices that often exceed hourly wholesale costs can give some retail customers an incentive to invest in DG that appears economic at the averaged retail price, but which is actually more expensive than the wholesale cost of generating power in most hours. Efficient prices that reflect actual wholesale costs provide incentives to customers to invest only in DG that is actually economic when compared to wholesale power costs (e.g., co-generation whose cost is low due to the customer's dual use of power and process steam), or that has other value, such as providing backup power to ensure reliability.

Sell-back rates. If DG consumers produce more power than they need, can they sell power back onto the grid, and at what price? For small customers with basic monthly metering, these questions generally involve issues of net metering, or the process by which consumers may be credited for energy generated on site that exceeds their purchased energy. In principle, the prices that consumers are paid for excess power sold back onto the grid should reflect the value of that power to the system at the time that it is sold back. Fixed retail rates and the lack of hourly metering typically rule out that approach. In addition, since retail rates reflect not only average wholesale energy costs, but also a portion of fixed distribution services costs, crediting customers at their retail rate for net sales to the utility has the potential for substantial overpayments, or subsidies. If DG customers' retail rates were unbundled to distinguish generation services from delivery services, and modified to reflect time-varying usage and prices, then utilities would have less concern about net metering, and consumers would receive more appropriate and efficient price signals than those provided by standard rates. A barrier to this solution is the cost of hourly metering equipment.

Standby rates. DG customers who wish to purchase power from a utility to replace power from DG equipment during periods of maintenance or occasional outages can potentially impose significant costs on their energy supplier if these purchases are unrestricted. For example, the supplier might have to make sufficient distribution system and generation capacity investments to ensure that they are available at any time needed by the DG customers. As a result, utilities often impose relatively severe standby rates to discourage DG. However, if restrictions are placed on the customers' right to purchase replacement power, or if rates are reformed to ensure recovery of the fixed costs of transmission and distribution facilities, then the potential standby power costs to utilities may be largely avoided. Efficient pricing principles suggest that standby rates for customers with distributed generation should reflect the potential cost that such customers impose on the system. For example, these costs can be high if the customer has the right to consume unlimited backup power, regardless of market conditions, in case their generation fails, thus requiring the utility to maintain sufficient reserve capacity to cover such an occurrence. However, utilities' cost exposure may be limited by the use of contracts that restrict the amount of backup power that the customer has a right to purchase, and by charging prices that reflect market costs at the time the power is purchased. Thus, standby rates need not automatically reflect the highest-cost scenario, but can reflect the expected costs and conditions implied by standby power contracts. Some utilities have been able to replace complex and potentially inefficient standby tariffs to co-generators and self-generators with a version of two-part RTP.[20]

2.6 Pros and cons of alternative time-based price structures

The alternative efficient time-based price structures described in Section 2.4 are characterized by different features that generally relate to the extent to which they reflect variations in wholesale power costs, and which may affect their attractiveness to both consumers and energy providers.

Figures 2.7 and 2.8 illustrate the degree of linkage between hourly wholesale energy costs and several of the time-based price structures. These figures plot prototypical hourly wholesale prices for two five-day periods that might be characterized as a low-cost and a high-cost summer week (five weekdays), and illustrate how several different retail energy price structures reflect those wholesale costs. For example, the flat seasonal rate reflects an average across all low-cost and high-cost hours in the season, but conveys no information about how costs differ across days or time periods. The TOU rate reflects average differences in expected costs during peak, shoulder and off-peak periods of each weekday, but does not differentiate between days on which wholesale energy costs in any of those time periods are low, moderate, or extreme. The variable-CPP rate illustrates how the availability of the critical price feature can reflect periods of unusually high wholesale costs on short notice and provide incentives to consumers to reduce consumption during those critical periods. (The version shown has the flexibility of sending either of two alternative critical values. A traditional CPP rate would only have the ability to send one critical value on any of the high-cost days.) Finally, the wholesale price curve itself illustrates how hourly retail prices that are indexed to wholesale prices can match the pattern of wholesale costs exactly.

[20] See Glyer and Locke [1998].

Figure 2.7 Alternative time-based rates – low-cost summer week

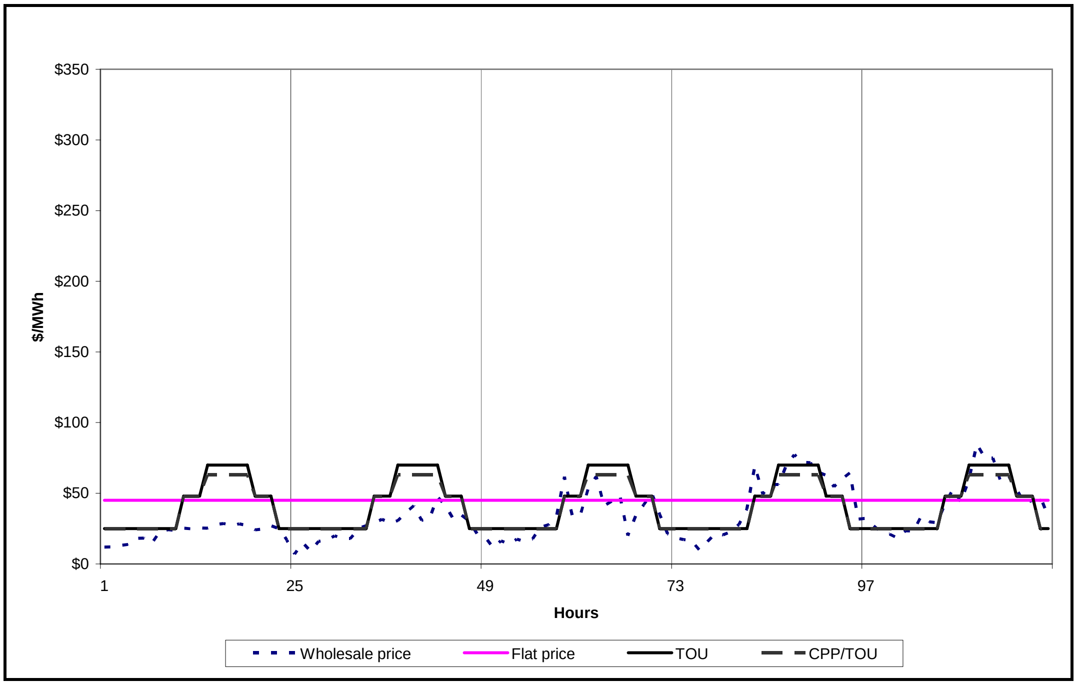
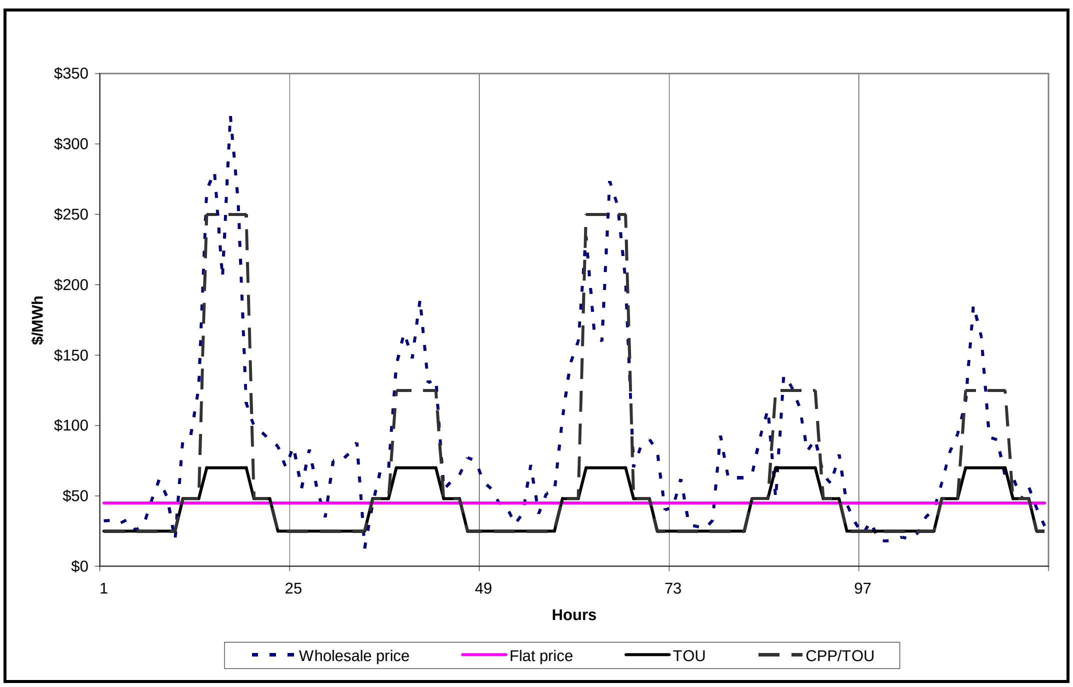


Figure 2.8 Alternative time-based rates – high-cost summer week



The various lines in the figures illustrate a number of important positive and negative features of retail price structures that reflect hourly wholesale costs to varying degrees. First, the substantial variation in hourly wholesale prices illustrates why many consumers might view hourly pricing, while accurate, as too complicated or risky without some type of risk-management feature.[21] Second, the widely varying hourly prices illustrate why providers need to include a risk premium in guaranteed retail rates. Third, the TOU rate reflects the broad differences between the hourly prices in certain time periods. It is predictable and relatively straightforward for customers to understand. However, it provides relatively inaccurate price signals to consumers on a daily basis. For example, TOU peak prices typically exceed wholesale energy costs on many days, but give consumers too low of a price signal on the important days of unusually high wholesale costs.

Fourth, the CPP prices illustrate several useful properties of a price structure that involves fixed prices much of the time, but contains some prices which can vary on a daily basis to reflect wholesale market conditions. In particular, the availability of the critical prices means that the non-critical peak TOU price can be offered at a discount relative to the traditional TOU rate, as shown in Figure 2.7. In addition, the variable-CPP rate shown in the figure illustrates the potential value of designating at least two alternative critical price levels, which may be implemented under different sets of wholesale price conditions to provide price signals that are more accurate than a single critical price.

Finally, the critical price levels also illustrate the potential magnitudes of the rebate payments that would be offered to customers under a peak-day rebate program for load reductions below a baseline level. That is, as described in Section 2.4.2, a CPP rate and a peak-day rebate provide similar price signals to consumers on a short-notice basis about cost conditions in the wholesale market. However, they have different implications for consumers and energy providers. For example, consumers may view rebate programs as having less downside risk of facing occasional high critical prices as under CPP rates. For energy providers, billing under CPP is more straightforward than under a peak-day rebate and does not require calculating baseline loads from which to measure load reductions.

2.7 History and future of efficient retail pricing

Various efforts to improve the efficiency of retail pricing have been made at different points over the past 30 years. These include a number of residential TOU pilot programs undertaken in the 1970s, the development of several RTP programs in the early 1990s, and the investigation of advanced metering and communication technology combined with TOU/CPP over the past 10 years. Appendix B provides a brief summary of the history of these efforts. Many of the regulatory barriers that have always limited the adoption of more efficient retail pricing remain, as described in Section 3. However, two important new factors are intensifying interest in efficient pricing. These are the opportunities provided by more widespread installation of advanced metering technologies, and the perceived critical need to improve the link between wholesale and retail energy markets. The next section discusses strategies for introducing more efficient retail rates, given differences in evolving power market structures.

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[21] The residential real-time pricing rate offered by Commonwealth Edison and implemented by the community agency in Chicago offers a counter-example that suggests that at least some consumers are willing to accept hourly pricing if it is marketed effectively.

3. STRATEGIES FOR IMPLEMENTING EFFICIENT PRICING

This section discusses efficient pricing of generation services under the two general forms of retail market structure: 1) markets that have been restructured to give consumers access to competitive retail providers, and 2) traditional markets consisting of utilities whose prices remain regulated by the states. Section 3.1 discusses efficient pricing in retail access markets, including regulated default or provider of last resort (POLR) pricing, and pricing by competitive providers. Section 3.2 discusses barriers to efficient pricing in traditional markets. Section 3.3 illustrates the barriers posed by standard class-wide flat rates through a stylized scenario of universal advanced metering combined with individualized electricity pricing for all consumers. Section 3.4 proposes strategies for overcoming existing barriers to efficient pricing in traditional markets.

3.1 Efficient pricing in retail access markets

Two distinctly different types of pricing co-exist in retail access markets. One is default/POLR service, which represents the prices received by consumers who do not choose a competitive provider, or for whom a competitive supplier is not available. The other is retail pricing by competitive providers. The types of pricing plans offered in competitive retail markets provide useful models for efficient pricing in traditional markets.

3.1.1 Default pricing

Default rates have often been determined legislatively as part of an original restructuring plan. In many cases, these rates were set at fixed discounted levels without regard to wholesale market prices, and thus make little contribution toward efficiency. Expiration of these below-market rates is causing rate shock because of the recent rise in wholesale energy costs due to high natural gas prices. Expiration of these rates provides an opportunity to introduce and encourage more efficient pricing. Setting efficient default rates which reflect wholesale market costs (for example, through periodic bidding processes for portions of the default load) is important for efficient wholesale and retail market operation. [22] Such rates give consumers an incentive to accept and respond to those efficient prices, or choose a service option that controls price risk (at a cost) to a level the customer is willing to accept.

For example, some states such as New York and New Jersey have required that default rates for customers above a certain size are hourly rates indexed to wholesale market prices.[23] These rates are designed to remove the distribution utilities from providing risk-managed pricing, and to encourage those consumers who are unwilling to accept the risk of basic hourly pricing to move to a competitive provider who will provide products that involve less price risk. In addition, they give consumers who remain on the default rate an incentive to respond to hourly prices.

[22] Oppenheim [2001] provides a discussion of default service pricing.

[23] Barbose, et al. [2006] discuss default pricing for large customers in several states.

3.1.2 Competitive retail pricing

Competitive retail providers sell generation services to customers who continue to receive customer and delivery services from their local distribution utility. The pricing plans offered by competitive providers represent useful illustrations of efficient pricing as it has evolved to date in the face of competition. As noted above, the retail energy prices offered by competitive providers are necessarily tied to wholesale market prices, and reflect their estimate of the expected cost to serve different types of customers. Reviews of websites and discussions with several competitive providers suggest that they offer the following types of pricing plans, which were described in Section 2:[24]

- **Hourly indexed pricing**. This pricing plan offers hourly retail prices that are indexed to wholesale energy prices. This product is typically selected only by large customers, particularly industrial customers who are interested in the lowest possible prices and prefer not to pay the risk premium inherent in fixed prices.
- **Block and index pricing**. Some customers who select hourly pricing choose to manage their price risk through financial hedges in the form of contracts for differences on a portion of their load. These take the form of contracts for fixed blocks of power at fixed prices, with differences between actual hourly usage and the fixed block level charged at hourly indexed prices. Prices for fixed blocks of power carry a smaller risk premium than open-ended fixed prices since they remove quantity risk to the energy provider and may be linked to available forward contract prices in the wholesale market. Furthermore, the fixed prices on the fixed blocks of power limit consumers' exposure to hourly indexed prices on the portion of their load covered by the block contracts.
- **Flat pricing**. Most customers who choose competitive providers appear to prefer the certainty of fixed prices, either annual or seasonal, and are willing to pay the corresponding risk premium (one retail provider estimated that 70 percent of commercial and industrial customers choose a fixed price). Competitive providers appear to develop customer-specific fixed prices for large customers based on historical information on each customer's usage pattern. For smaller customers, providers may base price offers on knowledge of certain customer characteristics, such as retail business type.
- **TOU or CPP pricing**. In principle, competitive providers could design and offer TOU or CPP pricing plans. However, it appears that few customers ask for them, and such plans appear to represent a small or nonexistent market share.

Demand response services. Given the dominance of fixed prices at both regulated utilities and competitive providers, regional ISOs such as PJM, NYISO, and ISO-NE have designed and offered demand response (DR) programs, in which participating consumers can receive payments for load reductions below a baseline level. Competitive retail providers can facilitate their fixed-price customers' participation in relevant DR programs by bidding their load reductions into the ISO markets.

Effects of wholesale market structure

Designing each of the above retail pricing products requires estimates of future wholesale energy prices. However, in cases where capacity markets also apply, competitive providers need to recover the cost of charges for capacity costs. These costs could in principle be recovered through some form of demand charge that approximates the structure of a capacity charge. However, discussions with some competitive retail providers

[24] Detailed and comprehensive information from competitive providers is difficult to obtain due to its proprietary nature. However, some information has been provided in public presentations such as a conference presentation on hourly and block and index pricing by a representative from Pepco Energy Services (Kumm [2006]).

suggest that customer resistance to demand charges generally leads providers to recover capacity costs by spreading them out across consumers' total expected usage, in the form of an adder on the energy price. As a result of this competitive response to customer preferences, the structure of the wholesale market appears to not necessarily affect the type of retail pricing offered.

3.2 Efficient pricing in traditional markets

As described in Section 2.1, marginal costs of generation services can vary substantially by time and location for all types of energy providers. To reflect those costs, regulated utilities in traditional markets may in principle design and offer any one or a combination of the efficient price structures summarized in Sections 2.4 and 2.5. Different price structures may be most appropriate as default or optional rates for particular customer classes, such as TOU or some version of CPP to mass-market customers, and RTP to large commercial and industrial customers. And voluntary versions of these rates could be offered as well.

However, a number of technical, institutional and financial barriers have combined to delay widespread offers and acceptance of efficient pricing in traditional markets. This section describes a number of those barriers. Section 3.3 illustrates one of those barriers through an example of customized pricing for individual consumers in the presence of advanced metering. Section 3.4 suggests strategies for overcoming barriers.

3.2.1 Barriers to efficient pricing

The barriers to efficient retail pricing in traditional markets include technology issues and various concerns on the part of all relevant parties, including regulators, utilities and consumers, including:

- Technology issues, including the lack of hourly metering, and communication and control systems to support time-based pricing and short-notice price changes
- Regulatory concerns about metering costs and bill impacts on consumers from any change in current class-wide rates
- Utility financial disincentives, including:
  - the "throughput" problem of under-recovery of allowed revenue toward fixed costs that occurs if the fixed costs had been expected to be recovered through volumetric energy charges, and consumers facing time-differentiated energy prices reduce overall consumption
  - potential revenue losses from "free riders" who obtain immediate bill reductions under voluntary time-varying rates due to their favorable load patterns
  - questions about how utilities can share in the potential benefits (or at least avoid harm) from customers' load changes under time-varying prices, including the timing issue of matching near-term revenue reductions during high-price periods with future avoided capacity costs that do not translate into immediate cost savings
- Apparent lack of consumer interest in time-varying prices, with most consumers seeming to prefer the simplest flat rates

Advanced metering

Metering and billing costs have traditionally represented one of the largest barriers to utilities offering more efficient, time-varying price structures, particularly to smaller customers. Any time-varying price structure requires recording customer electricity usage on an hourly or at least TOU period basis, and it has been difficult to justify the cost of the required metering solely on the basis of economic benefits from more efficient pricing to small consumers. However, the calculus of the business case for hourly metering appears to have changed dramatically in recent years. Improvements in the technology and cost of advanced metering infrastructure (AMI) have resulted in a number of utilities deciding that AMI can be largely justified on the ground of improved operations, even without the additional potential benefits from improved retail pricing.

The nature of the cost savings and other potential benefits from AMI depend on conditions specific to individual utilities.[25] However, AMI offers substantial potential operating cost savings to utilities in many business and processing functions. In addition, estimates of the potential benefits that can be derived from efficient pricing facilitated by AMI can provide additional support for the business case for AMI. While the total cost of AMI investment remains high, the terms of the debate about whether pricing alone can justify the investment have changed dramatically. If the potential advantages to be gained from improving the quality of the interface between distribution utilities and customers are determined to exceed the cost, then one of the largest barriers to offering new forms of pricing to consumers will have been lowered considerably.

Recovery of fixed delivery costs

One of the barriers to utilities offering time-varying pricing, particularly for smaller customers, has been their concern about recovering fixed costs (e.g., distribution services costs) in addition to generation services costs, given the traditional rate design practice of volumetric (per kWh) pricing for small customers. That is, fixed costs are typically recovered by spreading them over an anticipated level of sales to the average customer (particularly for small customers). If consumers' actual usage differs from the planned level, then the utility may under-recover or over-recover its fixed costs. Several studies of pilot TOU and CPP programs have shown that consumers who face TOU or CPP rates often reduce their overall consumption by as much as 5 percent.[26] This reduction relative to expected levels of sales could result in utilities falling short in their recovery of fixed delivery costs. Possible strategies for addressing this issue are discussed in Section 3.4.

Class-wide rates, revenue attrition and customer bill impacts

Traditional retail rate-making establishes class-wide retail rates that apply to all customers in a broadly defined class (e.g., residential, small commercial and industrial). This practice, combined with the diverse range of customer types within each class, particularly for the case of mass-market customers, creates problems for offering voluntary time-based pricing products to the entire rate class. That is, traditional flat rates are set at levels needed to recover the average cost of serving the average customer in the group. However, the actual cost of serving some customers is higher than the cost of serving other customers, since costs vary by time of day, and customers differ

[25] Plexus Research, Inc. [2006].

[26] See King and Delurey [2006].

in terms of their fraction of usage in high-cost time periods. Furthermore, that fraction typically cannot be measured due to the lack of hourly metering.[27]

If an alternative time-based rate is offered in addition to the standard rate, then some customers (i.e., those with lower than average usage during peak periods) can achieve bill savings (implying reduced revenue to the utility), without having to change their usage pattern, by selecting the rate.[28] These customers are thus more likely than the average customer to select it. This outcome is known by several different terms, including an adverse selection, instant winner, or free-rider problem.

Note that the potential problem to the utility is revenue loss. However, from the customer perspective, it can be argued that the lower average price to the instant winners is fairer than the class-wide flat rate, since the cost to serve their load is below average. The utility's revenue loss may in principle be contained to the interval between rate cases, since the standard flat rate can be increased in the next rate case to account for the different mix of customers on the standard and voluntary rates. However, the implied need to increase the rate for non-TOU customers creates a potential regulatory problem.

Utility benefits from efficient pricing

Competition forces competitive retail providers to offer a range of pricing products, each of which is based on expected wholesale prices and the risk of offering fixed retail prices. In contrast, regulated utilities need economic incentives to offer alternatives to standard class-level tariffs. The various barriers discussed in this section illustrate that in many cases they face financial disincentives. However, given appropriate design and treatment of the various barriers, the benefits to be derived from customer response to time-varying price structures such as TOU, CPP and RTP can in principle be shared between participating customers and utilities. This is the case if the rate design matches retail prices with expected wholesale market costs, and if appropriate tracking accounts are used to deal with the timing issue of short-term revenue reductions and longer-term capacity cost savings associated with consumers' price-responsive load changes. Utilities may also achieve benefits from efficient pricing if it allows them to meet effective competition for new customers and load from other utilities within or outside of the state.

Customer resistance

Consumers appear to reveal mixed signals regarding alternatives to flat prices. On the one hand, evidence seems to suggest a strong preference for simple flat prices on the part of most consumers, and a general lack of interest in price structures that make it more expensive to buy electricity during peak periods of the day. This preference seems to be confirmed by the reports from competitive retail providers on the large share of their customers who prefer fixed prices. On the other hand, nearly every customer survey undertaken in association with residential

[27] Residential rates at some utilities have a declining-block structure in which the rate for an initial level of consumption is set at one level, in part to recover fixed costs, and the rate for usage beyond that level is set at a lower level that reflects average energy costs. Other utilities use an inclining-block structure in which rates rise at succeeding levels of usage. To the extent that high usage (particularly in the summer) tends to be associated with high levels of peak period consumption, inclining block rates may produce higher average bills for consumers with greater than average on-peak consumption, and therefore high-cost usage patterns. In general, however, a lack of time-based rates implies a range of differences between customers' average price paid and the average cost to serve them.

[28] The presence of disparities between customers' average price paid (i.e., bill divided by consumption) and the utility's average cost to serve them also occurs with more complicated rate designs such as combined demand charges and energy rates. These disparities are generally smaller in the case where the standard tariff consists of time-of-use rates, because customers with greater peak-period usage shares pay higher prices.

TOU and CPP pilot rate programs reports strong customer satisfaction with those rates on the part of participants.[29] In addition, the modest success to date of programs such as Gulf Power's CPP rate and Commonwealth Edison's residential RTP rate suggests that at least some consumers are willing to accept time-varying prices and the associated price uncertainty if well-designed products are available.

It is possible that further education, marketing and consumer experience with price structures other than flat pricing will produce greater consumer acceptance. One interesting new paper argues that the customer acceptance of CPP may depend on how the rates are designed and presented to customers, such as emphasizing the opportunities for saving money during critical periods rather than the possible downside of facing occasional high prices.[30]

Before turning to a discussion of strategies for improving the efficiency of retail pricing in traditional markets, we first illustrate one of the key barriers through an example of an alternative world in which all consumers are billed according to the actual or expected cost of their individual consumption pattern, as recorded by an AMI system. The properties of the types of pricing that would logically arise in this world illustrate the barriers provided by class-wide pricing and suggest strategies for improving the pricing efficiency.

3.3 Idealized world of individual customer pricing

Consider the case of a stylized electricity world in which all consumers have advanced meters which record hourly consumption, and are charged prices that reflect their actual consumption profile rather than a class-average profile. These conditions are analogous to the case of, for example, supermarkets, which charge customers for the specific items in their shopping cart, rather than setting a single average "price per shopping bag" that would charge the same average price to consumers of luxury items as to consumers of bargain items.

Consumers could be offered any of the price structures described in Section 2.4. The simplest approach would be to charge each consumer hourly prices that directly reflect the actual cost to serve them. However, most small consumers would want more price certainty. For those customers, TOU and CPP rates which reflect the expected cost of serving each customer's historical usage pattern in different time periods could be offered. For customers who wanted the simplicity and certainty of a flat price, customer-specific monthly, seasonal or annual prices could be offered, which would be based on the expected cost to serve each individual customer (e.g., based on each customer's historical usage pattern), and would include a risk premium to compensate the supplier (utility or third party) for bearing the risks incurred in making a fixed price commitment. Customers could also be offered fixed-bill products with an appropriate risk premium. The greater the simplicity and certainty of the price structure to the customer, the greater the administrative cost and risk to the provider, and thus the greater the risk premium. The implied continuum of price structures, shown in Figure 3.1, from hourly pricing to customer-specific flat prices and fixed bills, represents the range of examples of efficient pricing that can be offered in today's markets.

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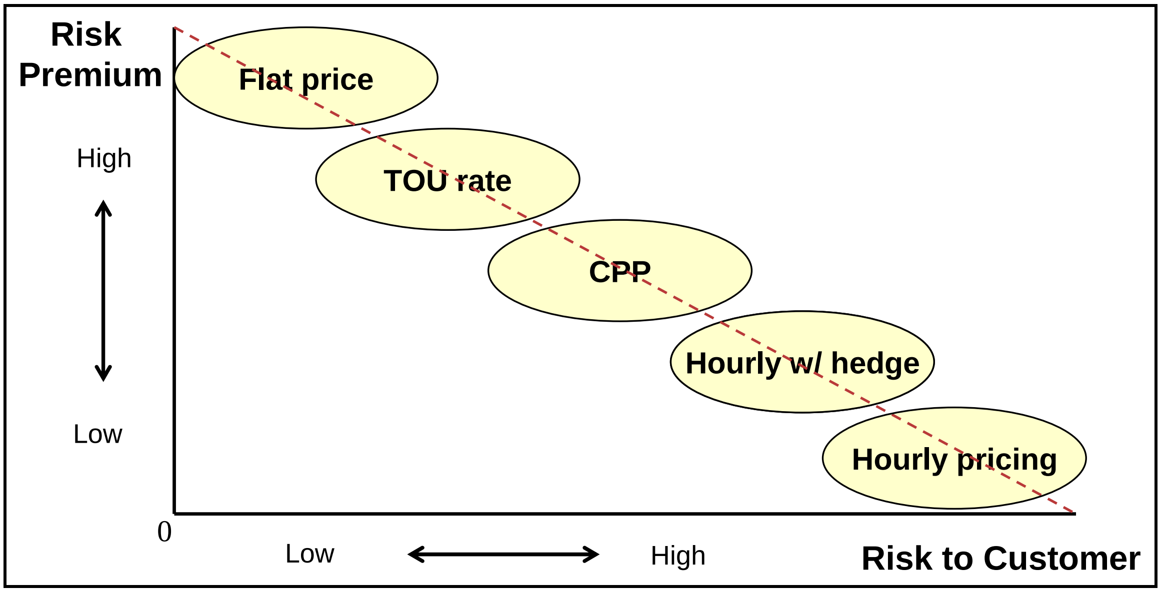
[29] Momentum Market Research [2004], Star [2006] and Voytas [2006] report broad customer satisfaction in the California SPP, Community Energy Cooperative and AmerenUE pilot CPP and RTP programs.

[30] See Letzler [2006].

Figure 3.1 Risk premiums and risk-based retail pricing



This idealized pricing approach essentially represents an extension of the actual current pricing practice of competitive energy providers. That is, those providers have an incentive to offer individual contract prices to customers, where the prices reflect the anticipated cost to serve each different customer. That is, under competition, individualized pricing minimizes the danger of losing customers whose cost to serve is lower than average and would face a higher bill under prices that apply to a broader class of customers. Under traditional regulation, individualized pricing would reduce utilities' risk of revenue loss that they currently face from offering efficient pricing to broad classes of customers. Customer-specific pricing is practical for large customers. However, the extra administrative costs may be too high for smaller customers, where prices are generally set for groups of customers, sometimes based on certain easily observable characteristic (e.g., type of retail establishment).[31]

3.3.1 Insights on efficient price signals

One important insight about customized retail prices which are based on individual consumers' actual consumption patterns is that even fixed prices like flat or TOU pricing can provide implicit dynamic price signals to customers of the actual time-varying cost of power. This is the case because future fixed-price offers will be based on consumers' actual usage pattern during the current contract period. For example, a consumer with a customized flat price contract who routinely consumes substantial power during high-cost peak periods will face a higher follow-on price offer than a consumer who is careful about limiting consumption during peak periods and on days that are announced as critical for power costs.

[31] It should be noted that utilities who offer fixed-bill products for mass-market customers create customer-specific offers to thousands of customers based on analysis of each customer's historical monthly usage pattern.

That is, even though these consumers' current flat price does not vary by day or time period, their price offers in future periods will depend on how they use energy today. This implicit efficient price signal provided by customer-specific flat pricing is likely not as strong as an explicit hourly or CPP price structure.[32] However, as consumers gained experience over time and the determinants of the price offers were explained and publicized, the implicit price signals could become stronger. Finally, it is important to note that it is the customer-specific feature of the price structure that provides the implicit price signal. Traditional class-wide flat rates provide no such signal to consumers because changes in their usage pattern have no discernable effect on their future rates.

3.3.2 Illustration of a barrier to efficient pricing

This idealized pricing framework illustrates one of the key barriers to moving toward more efficient pricing in regulated retail markets. That is, as described in the previous section, regulated utilities typically establish class-wide rates based on the cost of serving the average customer in the class. These rates effectively charge some customers within the class more than the cost of the energy that they consume (e.g., those consumers who tend to use less energy than average during high-cost periods), and some customers less than the cost of the energy that they consume. As a result, any mandatory change from class-wide fixed rates, such as from a flat price to a TOU or TOU/CPP price structure, will cause bill increases to some customers and bill reductions to others. These potential bill changes can lead to complaints by customer groups and concerns on the part of regulators.

Alternatively, if the TOU rates are offered as voluntary options to class-wide flat rates, then the customers most likely to select the option will be those who will receive immediate bill reductions due to their advantageous usage pattern.[33] These potential bill reductions mean reduced revenue to the utility, which in turn implies the need to recover additional revenue through the class-wide flat rate, thus presenting another barrier to more efficient pricing. Of course it can be argued that these rate shifts are appropriate, as those customers who achieve lower average prices through the TOU rate cost less to serve than the average customer, and those remaining on the flat rate and receive a rate increase cost the utility more to serve than average. Methods are also available to address the revenue effects resulting when voluntary rates are offered, such as restricting the voluntary rates to only some types of customers in order to minimize revenue losses. However, that adds to the complexity of pricing and may not completely solve the problem.

3.4 Strategies for encouraging efficient pricing

Available strategies for overcoming each of the barriers described in Section 3.2 are available. Some are straightforward, while others may require creativity and political will on the part of regulators. Possible strategies include the following:

- **Advanced metering**

The barrier created by the lack of availability of advanced metering appears to be falling. Utilities in some states (e.g., Pennsylvania) have installed AMI equipment for all customers, and those in other states (e.g., California) are planning to do so. The business case for AMI appears to be improving. In cases where the business case is close, then accounting for the potential benefits to be derived from efficient pricing can help make the case. With the advance of technology in all areas and the expansion of communication networks, it is difficult to imagine utilities continuing to use a decades-old technology as the primary link with their customers.

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[32] Technical details on the nature of this implicit dynamic price signal may be found in Glyer [2000].

[33] Since customers' usage by time of day is typically not metered, they have imperfect information about their share of usage in peak periods. However, they can develop reasonable estimates depending, for example, on whether they are typically home and using air conditioning during summer weekday afternoons.

- **Recovery of fixed delivery costs**

Several options are available for addressing fixed-cost recovery concerns. One approach is to shift toward recovering a larger portion of fixed costs through customer charges or demand (per maximum kW) charges rather than volumetric ($/kWh) rates. Demand charges are typically unpopular, particularly for small customers. Increasing customer charges typically raises justifiable fairness concerns about disproportionate impacts on customers in the lower usage ranges in a rate class. To address this issue, some utilities have adopted graduated customer charges which vary with typical levels of historical usage (i.e., small monthly charges for small customers and larger monthly charges for large customers), and thus help reduce differential impacts of increased customer charges.

Another approach is to take into account a forecast of customers' change in overall consumption in establishing the portion of the rate needed to recover fixed delivery costs. However, that approach can appear overly complicated and require tracking and analysis to ensure that appropriate revenues are recovered. Yet another approach is to set up a balancing account to track revenues toward fixed costs and make adjustments in future rates to recover shortfalls or return excess revenue. This approach has been used in some states to address a different incentive problem—utilities' resistance to encourage energy efficiency activities on the part of their customers which may reduce sales and thus the recovery of allowed fixed costs. Various decoupling mechanisms have been adopted to guarantee utilities recovery of fixed costs and thus remove that disincentive.[34] Similar approaches could be used to guarantee recovery of allowed fixed costs after offering time-based rates.

- **Class-wide rates, revenue attrition and customer bill impacts**

Aside from the metering issue, the traditional practice of class-wide flat rates, particularly for mass-market customers, arguably presents the greatest set of barriers to efficient pricing. As described in Section 3.2, these barriers consist on the one hand of potential revenue losses to utilities, and on the other hand potential differential bill impacts on consumers (i.e., some increases and some reductions), which in turn present consumer and regulatory concerns. The most effective strategy for overcoming these barriers would be for regulatory agencies to acknowledge both the importance of efficient pricing and the detrimental effects of cross-subsidization of customers within broadly defined rate classes. They could then allow the rate and revenue adjustments that would be needed to overcome the revenue shifts and reductions that would otherwise occur if utilities offered voluntary time-based rates.

For example, one typical approach that has been used to date to address the free-rider, or adverse selection, problem of customers with low peak-period consumption choosing voluntary time-based rates, and therefore causing revenue losses to the utility, has been to increase the voluntary rate with the objective of collecting the anticipated revenue losses. However, that strategy makes the voluntary rate less attractive and greatly reduces market acceptance. An alternative strategy would be to set the voluntary rates based on the (lower) expected cost to serve the customers most likely to volunteer, and to recover the resulting lost revenue through an increase in the standard rate. This strategy can be justified on the basis of a higher average expected cost to serve the customers remaining on the standard tariff. However, it may require political will to resist consumer complaints in the transition.

[34] See Kushler, et al. [2006].

A more general approach would be for regulators and utilities to accept the benefits of transitioning to more finely defined rate classes that would reduce the degree of heterogeneity of usage patterns and costs-to-serve within rate classes. An example is the practice used by some utilities to differentiate residential customers by ownership of major end uses such as electric space and water heating, which contributes to major differences in usage patterns, and thus expected costs to serve. The primary downside of more rate classes is the additional cost and complexity of conducting the load research, cost allocation and rate design needed to establish rates for each class.

The ultimate approach, which is feasible after installation of AMI systems, is customized pricing of the type described in Section 3.3. That is, each customer would face prices for generation services that reflect their actual or anticipated usage pattern (based on historical metered usage). The default rate could be hourly pricing, with optional fixed prices of various types (see Figure 3.1) which reflect an appropriate risk premium for any price guarantees. If individualized pricing were deemed too expensive, then multiple categories of prices could be established based upon features of customers' usage patterns, such as ranges of the percentage of usage in the on-peak period. With customized pricing, cross-subsidization is kept to a minimum, and there is no issue of revenue loss from customers choosing any voluntary rate or switching from one rate to another.

- **Utility benefits from efficient pricing**

The economic benefits to be obtained from efficient pricing, as illustrated in Appendix A, derive not from the prices themselves, but from consumers' load changes in response to the prices. Those load changes cause changes in both costs and revenues to the utility (as well as changes in bills and value to consumers). With well-designed rates, cost reductions will exceed revenue reductions (as in peak periods) and revenue increases will exceed cost increases (as in off-peak periods). The result can be an increase in net revenue to the utility. Under regulation, this increase can in principle be shared between utility shareholders and all customers, as is done under various financial incentive mechanisms.

- **Customer resistance**

The first strategy for overcoming customer resistance to efficient time-based pricing is to at least offer fairly priced voluntary rates that have straightforward designs and do not impose undue restrictions on consumers (e.g., requiring a certain amount of load response). As discussed in Section 3.2, at least some customers have demonstrated willingness to select time-based rates when they have been offered, and most customers who have participated in pilot TOU and CPP programs have expressed strong satisfaction. With time, effective marketing can overcome the inertia generated by consumers' "status quo bias" toward their existing rate offering, and the availability of easy-to-use control technologies may entice substantial portions of customers to select rate plans with time-varying prices.

Finally, as pointed out earlier, efficient pricing does not require all customers to face hourly pricing, only that customers are given choices of alternative price structures that reflect both wholesale energy costs and the risk of offering guaranteed prices. Consumers who are interested in the lowest possible prices and are able to tolerate price risk can choose hourly pricing or hourly pricing with some form of risk management (e.g., block and index, price caps, etc.). Other consumers who prefer price certainty and are unwilling to bear price risk have the option of choosing fixed prices, which contain a built-in risk premium based on anticipated wholesale price variability.

4. CONCLUSIONS

Industry experts increasingly recognize the importance of improving the link between wholesale and retail power markets. Efficient pricing that better links the two markets has the potential for improving the efficiency of electric power system operations and the industry's resource investments. Currently the two sides of the electricity market are largely disjointed, with varying wholesale prices on the supply side and fixed "one-size-fits-all" retail rates for all customers in a rate class on the demand side.

An efficient pricing outcome would have energy providers offer a range of price structures that are based on wholesale market prices but reflect different degrees of risk premiums and price guarantees, and have customers choose the price structure that best balances their relative preference for low prices and risk management.

The beneficial properties of efficient electricity pricing have been recognized for decades. However, efficient pricing in regulated states continues to face a number of barriers. Perhaps the greatest barrier aside from metering costs is the traditional practice of establishing class-wide standard tariffs at fixed rates that often bear little relationship to wholesale market prices. Class-wide rates contain built-in cross-subsidies among customers with different usage patterns, which present financial disincentives for utilities to offer choices of alternative voluntary price structures.

Current market developments appear to offer new opportunities to introduce more efficient rates. These include:

- The advent of organized wholesale power markets that provide transparent hourly prices, which can be used as the basis for retail prices
- An improving business case for advanced metering infrastructure, and increasing deployment of such systems for all customers
- Expiration of rate freezes on default rates in retail access states, which offer new opportunities to offer price structures that reflect wholesale market prices
- The requirements imposed by EPAct 2005, which has renewed regulatory interest in efficient pricing

We have identified several strategies that can be used to overcome remaining barriers to efficient pricing that continue to exist even given the above developments. These strategies include:

1. To overcome concerns about potential revenue losses from adverse selection of voluntary rates by consumers who expect to achieve immediate bill savings, offer fairly priced voluntary rates but allow adjustments to standard flat rates to ensure that they adequately cover the cost and risk of serving the remaining customers
2. To overcome concerns about fixed-cost revenue recovery due to reduced consumption under voluntary time-based rates, move toward greater use of graduated customer charges to recover fixed costs or revenue adjustment mechanisms to track allowed revenue toward fixed costs
3. To provide utilities with a financial incentive to offer voluntary rates, allow sharing of net revenue gains resulting from customer load response under time-based rates
4. To overcome customer resistance to complexity and price risk of time-based rates, offer simple, fairly priced optional rates combined with standard rates that include appropriate risk premiums for

guaranteed prices; market the rates effectively; and possibly combine them with communication and control technologies that facilitate consumers' response to varying prices

5. To further mitigate the financial disincentives to utilities to offering voluntary rates in the presence of class-wide standard rates, move toward greater refinement of rate classes to reduce the variability of within-class usage patterns, where the ultimate solution would be customized pricing for individual customers based on actual usage patterns measured with advanced metering equipment

Some of the above strategies would require potentially difficult regulatory decisions that could cause a range of bill changes as existing within-class cross-subsidies are removed. These changes would arguably increase rate fairness, as customers whose cost to serve is below average would no longer subsidize other customers. In addition, the more efficient rates that could be offered through these strategies should increase economic efficiency and reduce overall resource costs to all consumers.

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APPENDIX A. CUSTOMER BENEFITS FROM EFFICIENT PRICING

Benefits from TOU and CPP pricing

In discussing the potential value and customer acceptance of time-based pricing such as TOU and CPP, it is useful to examine how consumers and utilities can benefit compared to traditional flat rates. Figures A.1 – A.3 demonstrate through a series of stages how a TOU rate changes the timing of the revenue collected from consumers and how they can benefit by responding to TOU prices. Figure A.1 illustrates the existing conditions during on-peak and off-peak periods under a flat rate (P_F). The left panel (On-peak) shows marginal costs (MC_P), as reflected in wholesale prices, averaging considerably higher than the flat rate, while the right panel (Off-peak) shows marginal costs averaging less than the flat rate. Thus, the utility collects excess revenue during the off-peak hours that is used to cover the revenue shortfall during the peak period.

Figure A.1 Flat rate – differences between cost and revenue by TOU period

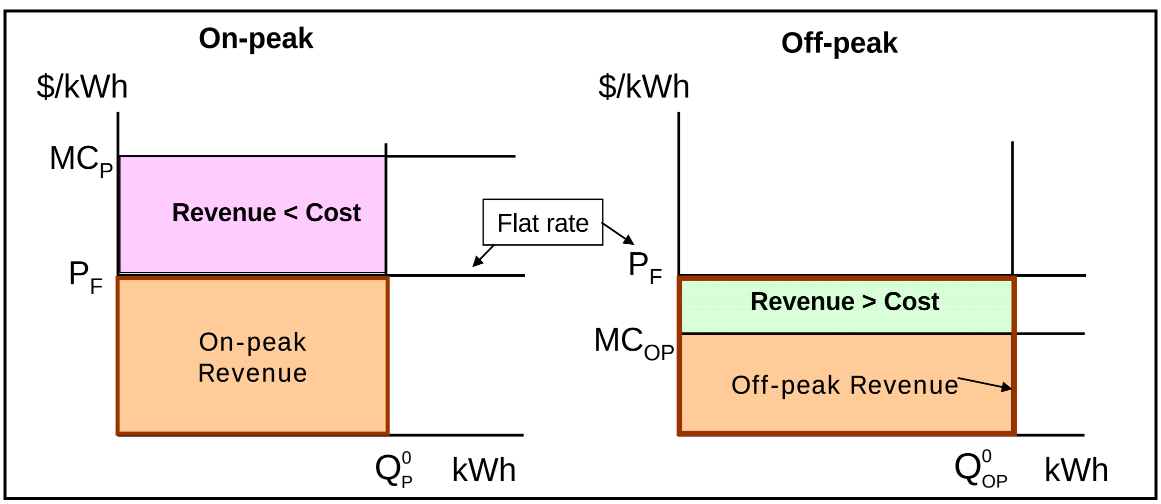
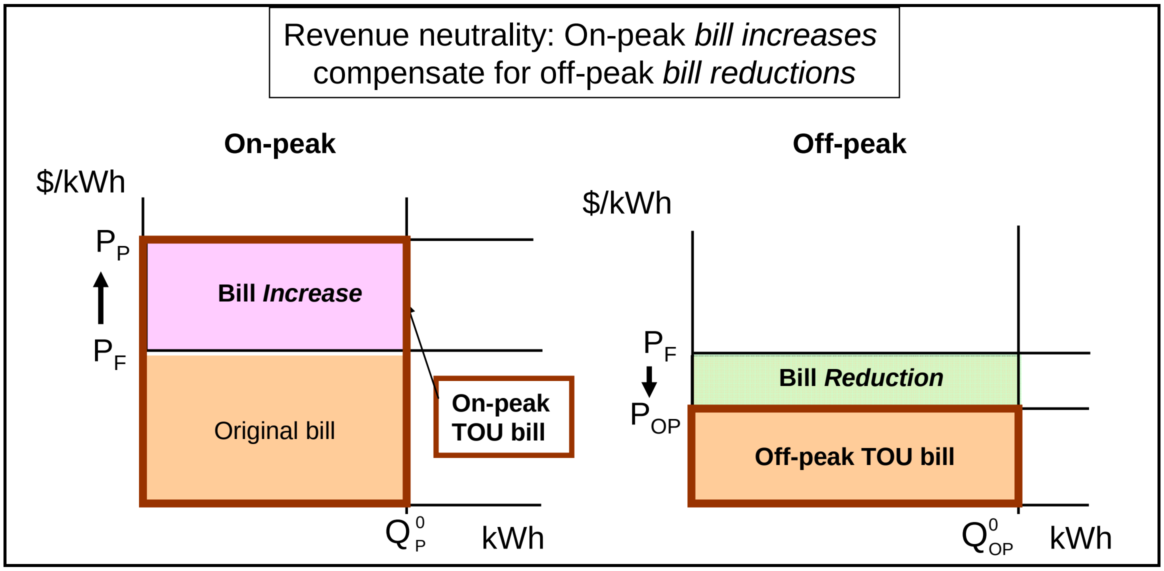


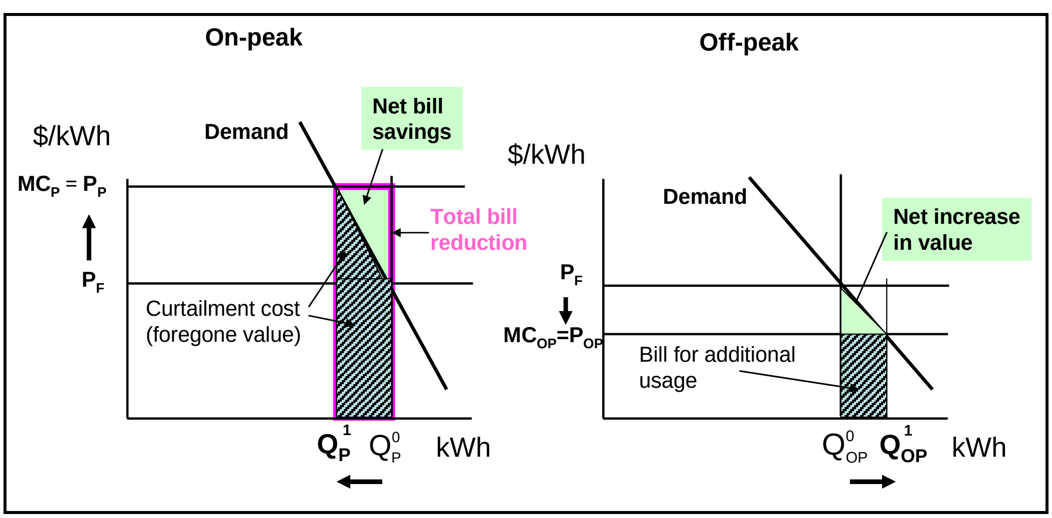
Figure A.2 shows the timing of bill changes induced by a revenue neutral (at average baseline usage) TOU design. The higher price during the on-peak period (P_P), combined with the lower price during the off-peak period (P_{OP}), relative to the flat price, imply peak-period bill increases and off-peak bill reductions. For the average customer usage pattern, these bill changes offset each other completely, leaving no net annual bill change (i.e., revenue neutrality) before accounting for any load response. However, in practice, the typical range of usage patterns in the residential class implies that some customers (e.g., those with a greater than average share of peak-period usage) will experience overall bill increases, while others (e.g., those with a less than average share of peak-period usage) will see bill reductions even before undertaking any load response.

Figure A.2 Revenue-neutral TOU rate – bill changes by TOU period



Finally, Figure A.3 illustrates how customers can benefit in both on-peak and off-peak periods if they change their usage pattern in response to the TOU prices. Economists traditionally measure changes in consumer benefits due to a response to a price change as changes in consumer surplus, which represents the difference between what consumers are willing to pay for a certain amount of a product (as reflected in their demand curve) and the market price that they actually have to pay. A conventional downward sloping demand curve reflects the value that consumers attach to a product or service; it implies that consumers are willing to purchase more of a product as its price falls, or less of it as its price rises. The right panel of Figure A.3 shows that the average customer who purchased Q^0_{OP} in the off-peak period at the flat price, P_F, increases consumption to Q^{TOU}_{OP} at the lower off-peak TOU price. In so doing, his bill goes up for the additional usage, but the total additional value that he experiences from the additional usage implies a net increase in value, or benefits equal to the triangular area under the demand curve and above the off-peak price, P_{OP}.

Figure A.3 Consumer benefits from price response



The left panel shows that during the peak period the average customer, who purchased Q^0_P in the peak period at the flat price, reduces consumption to Q^{TOU}_P at the now higher TOU peak price, P_P. By reducing consumption, he reduces his bill by the tall rectangular area outlined in bold lines. However, this curtailment in usage comes at a cost; the consumer loses some value from the foregone consumption (e.g., experiences some discomfort after raising the air conditioner thermostat setting on a hot day), as indicated by the hatched area under the demand curve. The net result is again a gain in value, equal to the bill reduction less the foregone value.

The same left panel could be used to illustrate the effect of an occasional critical price event under CPP pricing. In this case, the TOU on-peak price would be replaced by the critical price, and the average of wholesale prices in the period would represent a considerably higher level. Consumers would still benefit by reducing usage so long as their bill savings exceeded their curtailment cost. The consumers' load curtailment also benefits the power system, as costs to the utility are reduced by the amount of the wholesale price for the amount of the curtailment.

This series of figures demonstrates an important fact about the potential economic benefits to be derived from moving from flat to time-varying pricing which provides a closer link between wholesale and retail prices—the potential benefits come when consumers modify their consumption in response to the time-varying prices. If consumers do not respond to TOU or CPP pricing, then the price changes only serve to shift revenue from one period to another. Fortunately, many years of research indicate that at least some portion of customers will respond to time-varying prices if given the opportunity.[35]

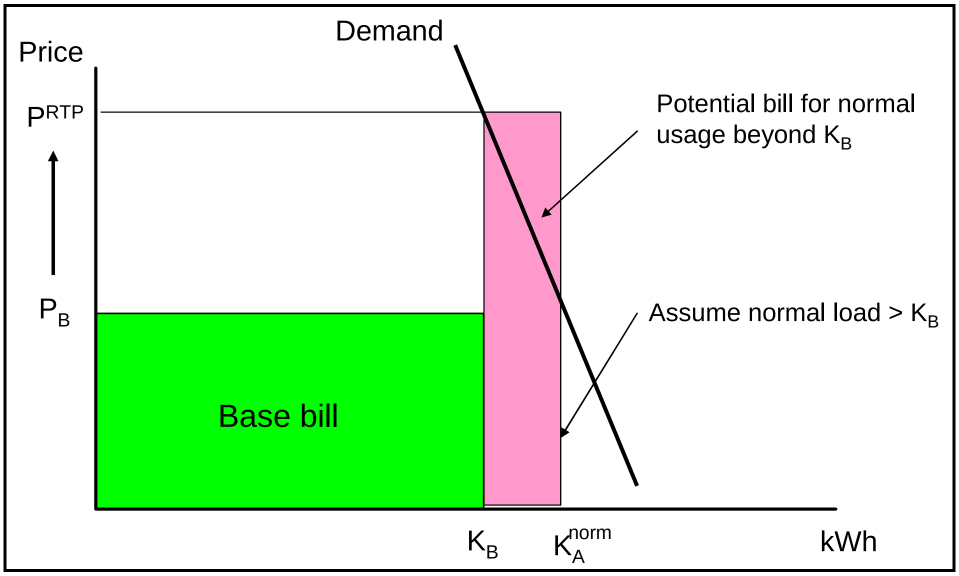
Benefits from two-part RTP

Two-part RTP effectively offers customers a financial contract for differences (CfD), which guarantees a fixed energy price for a fixed, customer-specific baseline level of usage (CBL). Under this design, customers pay market-based RTP prices for their entire load, but then also receive a financial adjustment to their bill, based on the CfD, that ensures that they pay no more than the guaranteed price (which under regulation is typically the standard tariff rate) for their baseline load. An equivalent characterization of this design is that customers pay the fixed price for their baseline load, and then pay RTP prices for any usage in excess of the baseline level, and receive credits at RTP prices for usage reductions below the baseline level.

Figures A.4 – A.6 illustrate how consumers can benefit by responding to prices under two-part RTP, whether those prices are higher or lower than the fixed prices they would otherwise face under their standard retail tariff. Figure A.4 illustrates the case in a particular hour of the RTP price reflecting low wholesale costs, where quantities are shown on the horizontal axis and prices on the vertical axis. The RTP customer's baseline load is shown as K_B, and the contract price (e.g., standard tariff rate) for that base load as P_B. The customer's price-responsive demand is shown by the sloping line passing through the point represented by the above combination of contract price and quantity. Under conditions of moderate RTP prices in which the customer's actual usage equals the baseline level, the customer's energy bill in that hour will equal the darkly shaded area labeled "Base bill."

[35] See Christensen Associates [2001] and Christensen Associates Energy Consulting [2005] for evidence.

Figure A.4 RTP customer benefits from price response at low hourly price

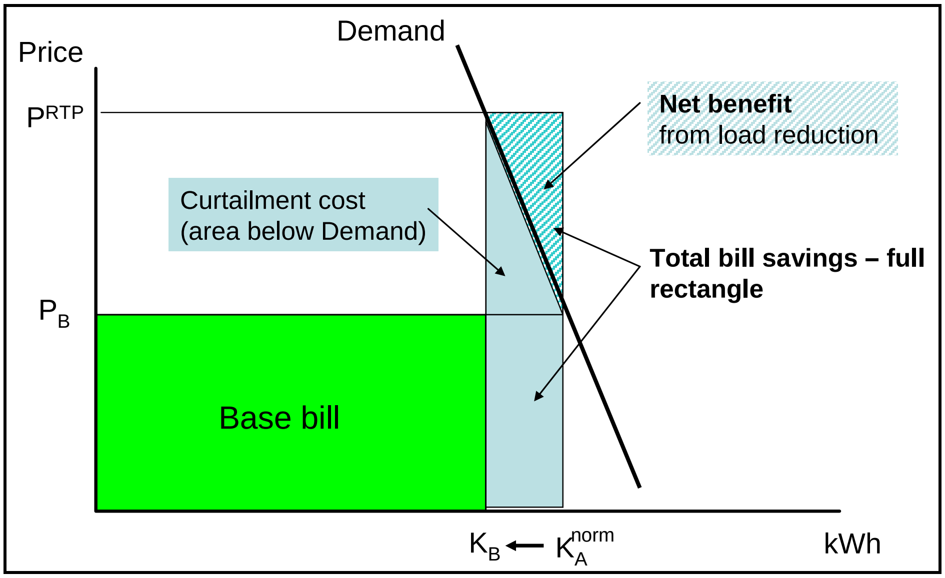


In a period in which wholesale market costs are low, producing a retail price of P^{RTP} in Figure A.4, the RTP customer increases consumption to K_A^{low} (i.e., the point where the sloping demand curve intersects the RTP price). The customer incurs a bill increase for the incremental usage ($K_A^{low} – K_B$), shown by the lightly shaded rectangle. However, by taking advantage of the low price, the customer receives positive net value beyond the amount spent on the increased consumption, which is shown as the triangular area under the demand curve and above ^{PRTP}.[36] This incremental net value represents, for example, the value of the additional product that the customer is able to produce in this time period, over and above the cost of the additional electricity. In other words, it signifies the reason that the customer was willing to increase consumption at the lower price in the first place.

Figures A.5 and A.6 illustrate, in two steps, how RTP customers can also benefit from reducing consumption when RTP prices are high. Figure A.5 shows the potential bill increase that a customer would face for usage beyond the baseline load if he did not respond to the high price. That amount is shown by the tall shaded rectangle. Figure A.6 shows how the customer can benefit by curtailing consumption in the face of the high price from the level that he would have normally consumed, K_A^{norm}, to the baseline level, K_B (i.e., the point where the sloping demand curve intersects the RTP price). By curtailing usage to this level, the customer avoids the entire potential bill increase. In doing so, however, the customer incurs a curtailment cost equal to a foregone amount of value, which is shown as the lightly shaded area under the demand curve. Comparing the bill savings with the curtailment cost implies that the customer's net overall benefit from responding in an hour of high prices amounts to the indicated upper-triangular area with diagonal hash lines.

[36] Demand curves represent points of incremental value to consumers, showing how much of a product they are willing to consume at a given price level.

Figure A.5 Potential bill increase at high RTP price – no price response



In these examples in which the RTP price is assumed to exactly equal the wholesale market price, the utility is indifferent to the customer's load response to either low or high RTP prices. In the low-price case, the revenue that the utility receives from the incremental load exactly covers the incremental cost. In the high-price case, the foregone revenue at the high RTP price is matched by the avoided cost that the utility would have incurred to procure the amount of the load change. However, if the utility applies a markup to the wholesale price, then it can earn net revenue on incremental sales. And if the customer's load curtailment allows the utility to sell power for which it has physical or financial contracts at a price that exceeds the RTP price (say at a real-time price that exceeds the day-ahead price on which the RTP price was based), then it can benefit from customers' load reductions at high prices as well.

APPENDIX B. BRIEF HISTORY OF EFFICIENT RETAIL PRICING

Despite the long recognition of the principle of efficient pricing that reflects the marginal cost of generating electricity, the practice of incorporating marginal cost-based pricing in utility rate-making has been slow in implementation.

1950s and 1960s

The period of the 1950s through the early 1970s was characterized generally by declining electricity costs, which provided little urgency for pricing reform. With marginal costs less than average costs, there was for the most part only academic interest in efficient, marginal cost-based pricing, with concern expressed that pricing at marginal cost would not recover sufficient revenue to cover utilities' total costs.

The 1970s Energy Crises

The situation changed dramatically during and after the two energy crises of 1973-74 and 1979-80. A series of factors combined to produce marginal costs that exceeded average costs by a considerable amount. These included higher fossil fuel prices, double-digit inflation and interest rates, rising construction costs, particularly for nuclear plants, and an apparent end to economies of scale in power plant construction.

The increased pressure on electricity prices led to new interest in setting retail prices to reflect marginal costs, and to thus encourage more efficient use of energy and less need for costly new capacity. This interest led to the quickened development of academic theory on electricity marginal costs. It also encouraged the National Association of Regulatory Utility Commissioners (NARUC), the Edison Electric Institute, and the Electric Power Research Institute (EPRI) to collaborate in drafting a comprehensive *Electric Utility Rate Design Study* to assess appropriate methods for estimating marginal costs and the "feasibility and cost of shifting various types of usage from peak to off-peak periods." This multiyear study resulted in multiple volumes of reports on marginal costs, time-of-use pricing, load management, and related topics.[37]

At around the same time, the Federal Energy Administration, the predecessor of the Department of Energy, funded a series of residential time-of-use pricing experiments to assess how customers would respond to peak and off-peak prices. Mitchell, Manning, and Acton [1978] reported that by 1977, state rate proceedings in California, Michigan, New York and Wisconsin led to the first use of TOU rates for very large customers. For example, a Pacific Gas and Electric (PG&E) tariff moved large customers from old declining-block demand and energy charges to new seasonal demand and energy prices that differed by peak, shoulder, and off-peak periods.

Not long after, Congress passed the Public Utility Regulatory Policies Act (PURPA) in 1978, which required state regulatory commissions to consider the cost effectiveness of retail rates designed to reflect differential costs of serving various types of customers, and the variation of costs by time of day and season, as well as provision

[37] See Faruqui and Malko [1981] for a summary of the TOU pricing studies.

of interruptible service rates for large industrial consumers. PURPA led to considerable expansion of load research metering to establish the costs of serving different customer classes, and to more widespread and explicit use of marginal costs in retail rate design. Interestingly, EPAct 2005 modifies various sections of PURPA to further require utilities and state commissions to assess the potential value of advanced metering equipment and of time-based rate and demand response programs.

Late 1980s and 1990s

The global movement toward restructuring and/or deregulation of regulated industries such as railroads, airlines, and telecommunications also encompassed the electric power industry, producing new trends in electricity pricing. A series of EPRI pricing conferences during the 1990s carried themes such as “Pricing in Competitive Electricity Markets,” “Market-Based Pricing,” and “Pricing in Transition.” Utilities saw competition in various forms, including competition from other fuel types such as natural gas, competition for large customers from other regions within or outside of the state, and, in states that allowed retail competition, for all customers.

One effect of competition and industry restructuring was cost unbundling into customer, wires (delivery), and energy services. In addition, one of the pricing mechanisms used to address competition was real-time pricing, in which hourly prices are based on anticipated marginal costs, typically for the following day. PG&E is generally credited with starting the first RTP program in the U.S. in the mid-1980s. However, the prices in that program far exceeded marginal costs because of that program’s one-part design: all RTP revenue requirements were recovered solely through the RTP energy charge. To get efficient energy prices, Niagara Mohawk instituted, in 1988, the first two-part RTP design, in which hourly prices reflected hourly marginal costs, and revenue recovery was achieved through access charges on a baseline level of usage. This was followed in 1992 by a similar two-part design at Georgia Power Company, which has since grown into the largest RTP program in the U.S.

Post 2000

A series of factors have combined in recent years to intensify interest in dynamic retail pricing that reflects marginal costs and demand response programs that encourage peak load reductions through payments that reflect marginal costs or market prices. These include:

- A series of extreme wholesale price spikes in 1999 in the Midwest and Eastern U.S., in which prices in a few hours rose to levels of around $8,000 per MWh
- The California crisis of 2000-2001, in which wholesale prices repeatedly rose to their capped level, leading to financial crises and rolling blackouts
- A recognition that organized wholesale energy markets (e.g., PJM, New York ISO, ISO New England, and California ISO) need some degree of responsive demand to operate efficiently

Much of the discussion of responsive demand in organized wholesale markets has taken place in the three regions in the Eastern U.S. in which retail competition has been initiated. Since the distribution divisions of the remaining utilities provide only default service to consumers who have not selected a competitive energy provider, there has been relatively little focus on innovative rate design on the part of those utilities. In fact, some states, such as New Jersey, have required that default service for consumers above a certain size be priced at hourly market prices. This gives consumers an incentive to select an alternative provider who will offer a less risky product. As a result of the lack of emphasis on efficient retail pricing for regulated utilities, efforts to promote responsive demand have focused on demand response programs organized by the regional ISOs.

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