Primer on Demand-Side Management

With an emphasis on price-responsive programs

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Chapter 1 - Overview of the Primer

The practice of Demand-Side Management (DSM) has evolved over the past three decades in response to lessons learned from implementation in different global settings, and also in response to the changing needs of restructured power markets.

The most notable change that is occurring today is the inclusion of programs that emphasize price responsiveness in the DSM portfolio. Traditionally, DSM programs were confined to energy efficiency and conservation programs with reliability-driven load management programs being used occasionally to manage emergency situations. Electric prices were taken as a given when designing such programs, hampering the eventual success of all such efforts.

This Primer has been written to introduce the new concepts of price-responsive DSM that are currently being investigated in a variety of different market settings. It highlights different criteria and taxonomies for classification and evaluation of DSM programs and recommends programs that will likely provide a better fit with the objectives, expected needs and outcomes of DSM initiatives in developing and transition countries. As defined in this Primer, such initiatives include both load shifting programs (that either clip peak loads or shift energy used in the peak period to off-peak periods) and efficiency programs (that reduce the total amount of energy).

The Primer illustrates the general concepts of DSM programs with examples that are drawn out of necessity from developed countries. These examples focus on the new crop of DSM programs where price responsiveness is a primary component of the DSM effort. Very few examples of price-responsive DSM programs currently exist in developing countries, even though there are exceptions that are noted in this document. While it may be true that many developing countries are a ways away from being able to implement such programs, there is nothing in principle that prevents electricity customers in developing countries from responding to time-varying prices in the same way as customers in developed countries. Price response is a feature of competitive markets globally, whether they be in developed or developing countries, and whether they are for electricity or other goods and services.

The purpose of the Primer is to provide successful examples of price-responsive DSM programs from the developed world and by discussing their workings, show that they can be also be applied to the developing world. Of course, before price-responsive programs can be implemented in the developing world, certain pre-requisites pertaining to metering and billing practices would have to be implemented. These are discussed in the report.

The Primer describes a variety of different cost-benefit tests that can be used to assess the efficacy of different typical DSM initiatives. The strengths and weaknesses of these different tests, both from a theoretical and practical perspective, are also discussed.

It also includes a discussion of how a DSM activity is likely to be judged from the perspective of the power enterprise, its customers, and society, as represented by the Energy Minister and the

Environment Minister. In other words, it discusses how each one of these constituencies will decide whether or not to implement a particular DSM program.

Finally, the Primer also includes a common "glossary" of the DSM nomenclature, highlighting how the DSM related expressions might have different connotations depending on the context or geography in which they are used.[1] It also presents a preferred nomenclature for DSM initiatives.

[1] There does not seem to be a common nomenclature. DSM programs are sometimes classified as economic or emergency. In other instances, DSM programs focus basically in load shifting. That seems to be the primary objective of organizations such as PLMA . Sometimes DSM is a synonym for DSR (Demand Side Response), focusing basically on load shifting, while efforts to rationalize overall consumption are not classified as DSM or DSR, and are indeed qualified as "Efficiency" programs.

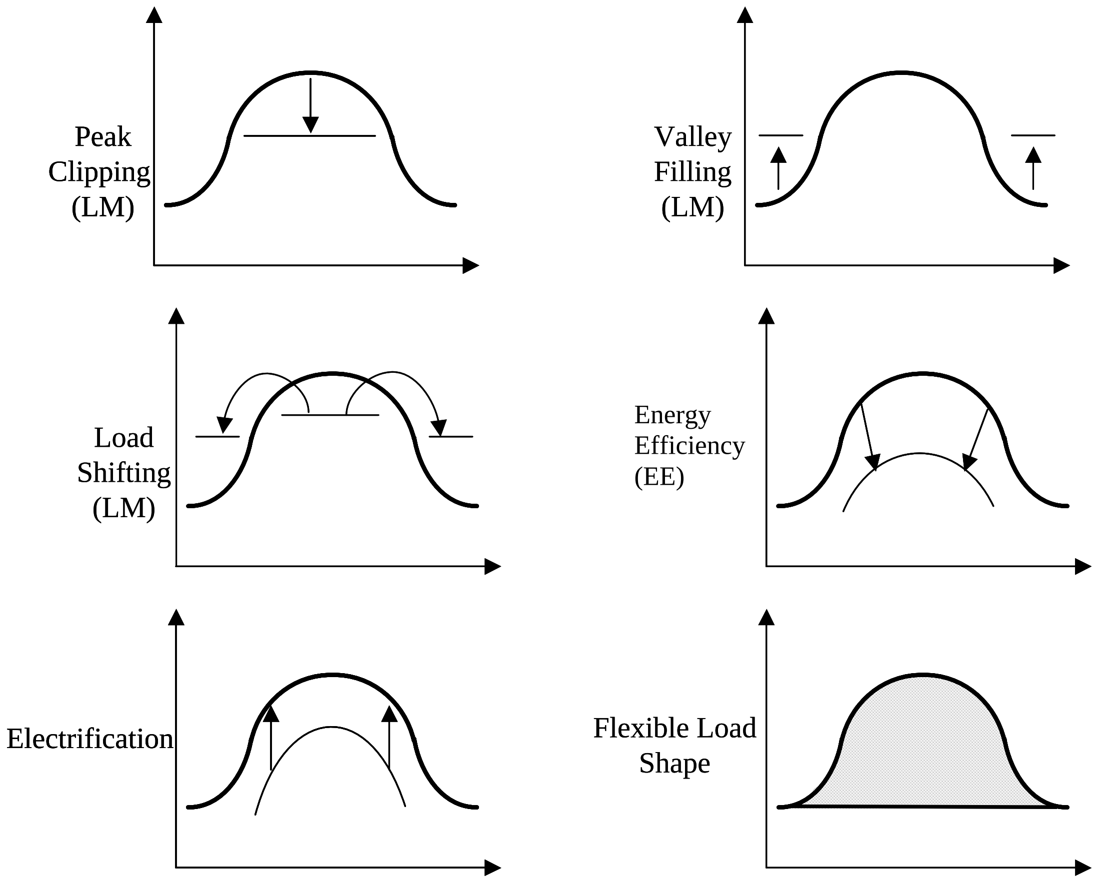
Chapter 2 - What is DSM?

DSM encompasses "systematic utility and government activities designed to change the amount and/or timing of the customer's use of electricity" for the collective benefit of the society, the utility and its customers. As such, it is an umbrella term that includes several different load shape objectives, including load management (LM), energy efficiency (EE) and electrification. These concepts were summarized in a number of reports published by groups such as EPRI and others in the 1980s and early 1990s. In 1993, EPRI put out a report that synthesized the key findings of these reports: see Barakat & Chamberlin, Inc. (1993).[2]

The following figure illustrates the six load shape objectives commonly associated with DSM. Peak clipping, valley filling and load shifting are classified as load management objectives. Energy efficiency involves a reduction in over all energy use and is sometimes referred to as energy conservation. Technically speaking, the two are different since the level of energy service (e.g., the level of lighting in a room) is preserved under energy efficiency but declines under energy conservation. Electrification involves load building over all hours and is often associated with customer retention programs from the perspective of the utility. It can also involve the development of new markets and customers. Flexible load shape involves making the load shape responsive to reliability conditions.

[2] Researchers at the Electric Power Research Institute (EPRI) coined the term DSM in the early 1980s, while working on a joint project with the Edison Electric Institute at a meeting in Chicago. For one of the early discussions of the concept, see the paper by Clark W. Gellings, Pradeep C. Gupta and Ahmad Faruqui, "Strategic Implications of Demand-Side Planning," in *Strategic Management and Planning for Electric Utilities*, edited by James L. Plummer, Eugene Oatman and Pradeep C. Gupta, Prentice-Hall, 1985.

Figure 2-1
Load shapes



2.1 The case for DSM

Governments worldwide are seeking to liberalize their power sector, to reduce costs associated with the generation and transportation/delivery of power, promote innovation, improve productivity and enhance international competitiveness. For instance, reform efforts appear to have realized the desired objective in Britain. Britain was able to double its labor productivity in the electricity industry between fiscal years 1990/01 and 1997/98. Prices rose initially, due to market power being exercised by the two large generators. However, once price controls were instituted and the number of generators increased, they declined in real terms, making consumers better off.[3]

In the aftermath of the Enron debacle in the US, and California's disastrous attempt at deregulating the power industry, policy makers in developing countries have become wary of

[3] See Chapter 6 in Newberry (1999) for a detailed discussion.

restructuring.[4] These failures should not deter them from continuing with the liberalization of their state-owned electric utilities, which are often the least efficient and often the most corrupt of the public enterprises.[5]

Liberalization does not mean privatization, but cash-starved governments often equate the two. Very few governments in developing countries can afford to keep on building power plants to meet the growing demand for power. For example, India anticipates the need for 100,000 MW of new capacity between now and the year 2012. This would require a capital outlay of $120-160 billion, and is beyond the means of the Indian government.

Privatization might provide a way out for cash-starved governments, assuming that the current turmoil in the US capital markets subsides, and power companies such as Calpine, Dynegy and Williams are able to stabilize their corporate finances. But it is premature to think of privatization without ensuring that electricity is efficiently priced. Investors would be reluctant to buy a state-owned company that is losing money since it would take a lot of management effort to turn it around, and even then the plan would be fraught with some risk that could only be overcome is substantial changes can be implemented in the existing legal, regulatory and commercial framework. A recent survey finds that two-thirds of investors rank self-sustaining retail tariffs and cash-flow discipline as the most important factors in screening privatization prospects.[6]

Governments should begin their liberalization program by focusing on pricing reform. As a general rule, prices should convey to consumers the cost of the resources that are used to make a product, and convey to investors the returns they can expect to get by making the product. Supposing an acceptance of the underlying assumption that electricity should be viewed as a "commodity" instead of a "public good," the principle stated above is equally applicable to electricity. When consumers do not see the real cost of electricity in their power bills, they over-consume energy, and that misdirects excessive capital and fuel resources to the power sector. This is especially true during peak periods, when the cost of producing electricity is much higher than during the off-peak periods, largely because electricity cannot be stored in large quantities economically due to technological reasons.

The problem is compounded when corrupt officials and politicians "sell" electricity illegally on the black market. For instance, power theft amounts to $300 million in New Delhi.[7] Up to 40 percent of the electricity vanishes as it passes through the industrial districts. People living in the wealthier districts tap another 10-15 percent to run their air conditioners. Such problems caused 350 million people to suffer prolonged blackouts after the entire Western grid collapsed. The Delhi Vidyut Board came under pressure to scuttle its privatization, just ten days after it was privatized, because it threatened to stop the illegal practices. At the national level, power theft in India amounts to $5.4 billion annually, or more than one percent of GDP.[8] The situation in Pakistan is similar on a percentage basis. According to the Asian Development Bank (2000),

[4] The experience of California is analyzed in Faruqui et al. (2001).
[5] See Malik (2002) and Sharma (2002) for a discussion pertaining to Pakistan and India respectively.
[6] The survey is posted on www.worldbank.org/energy.
[7] Devraj (2002).
[8] Sharma (2002).

power theft in Pakistan in 1999 amounted to $600-850 million annually, or more than one percent of GDP, as in the case of India.

Revenue insufficiency of their electric utilities has stymied governments in much of the developing world for years. The problem is not insoluble, but it can only be remedied in stages. First, governments, including the ministry of energy and appropriate electricity regulatory commissions, should reform rate design, encouraging consumers to shift their usage to less expensive periods. Second, they should reform the rate level, encouraging consumer to use less electricity if initially rates were lower than average costs, as they are in most developing economies. It is important that this sequence be followed, to minimize political complications. Thus, if consumers choose not to change their pattern of use in response to the new rate designs, their electricity bill would stay unchanged. Chapter 5 will further elaborate on this reasoning.

2.2 DSM continues to evolve in response to changes in industry structure

Over the past three decades, DSM activity in the U.S. (and to a large extent in Canada) has been characterized by five waves of programs. In many ways, this evolution of activity in the North America parallels developments around the globe. To provide a frame of reference on how DSM needs to evolve to changing utility structures in the developing world, these five waves that characterize the North American DSM experience are briefly described below.

First Wave: 1970s

The first wave took place from the mid to late 1970s and was triggered by the Arab Oil Embargo of 1973 and the Iranian Revolution in 1979. Both events served to raise the cost of energy and created a rationale for conserving energy. Thus, the focus of this wave of DSM activity was on designing and implementing energy conservation and load management (C&LM) programs. It was generally recognized that electricity prices did not reflect the new marginal costs and since prices were to be taken as a given for political reason, other ways had to be found to give customers an incentive for reducing usage. Programs were initiated to reduce loads on the presumption that it was less expensive to reduce loads through DSM than build new power plants. Because of the crisis mindset, this crop of programs was designed to achieve quick results. Not much time and budget went into monitoring and evaluating program impacts. There was a heavy reliance on “soft” measures such as information and audits. On the pricing front, time-varying rates were instituted for large commercial and industrial customers. And 16 experiments were conducted in the U.S. by utilities, in concert with the U.S. Federal Energy Administration (a precursor to the U.S. Department of Energy) with time-of-use (TOU) pricing for residential customers.

Second Wave: 1980s

The second wave took place during the 1980s. During the first part of the decade, there was a focus on achieving a comprehensive set of load shape objectives, including energy conservation, load management and strategic electrification, where the latter means expanding the uses of electricity to achieve other objectives such as economic development. It was expected that DSM programs would be regarded as playing a key role in utility resource planning. This led to the concepts of least-cost planning and integrated resource planning.

In the second half of the decade, concerns surfaced that large DSM expenditures on energy efficiency and conservation programs were resulting in revenue losses to the utilities. These concerns were justified, since DSM spending was lowering sales but the utilities had to cover their fixed costs regardless of the amount of electricity that was sold. Several "decoupling mechanisms" were devised to make the utilities whole by ensuring that they would recover their revenue requirement regardless of the amount of power sold. In other words, recognizing that utilities had large fixed costs, the mechanisms would ensure that sufficient revenues would be collected to cover these fixed costs, even if sales went down. This was achieved by raising electric rates by a small amount to cover the revenue deficiency created by lowered sales volumes. A series of cost-effectiveness tests were developed to ensure that programs would reflect the often-conflicting perspectives of the utility, its customers and society. Some experiments were carried out with real-time pricing (RTP).

Third Wave: Early 1990s

The third wave came in the early 1990s. It was brought on by new regulatory mechanisms for implementing DSM programs, comprised of the decoupling mechanism mentioned above, provisions for cost recovery and incentives to shareholders for investing in energy efficiency programs. The shareholder incentives involved raising the allowed rate of return to the utility in response to its performance on its DSM programs. DSM activity expanded rapidly in some states, but there was resistance in several others. There was a new focus on measuring the environmental benefits of DSM programs. The year 1993 was the high water mark for DSM spending in the US. Annual DSM spending reached $3.2 billion and represented 1.7 percent of utility revenues. DSM programs were in place in 447 utilities.

In the mid-1990s, competition from independent power producers, using natural gas-fired, modular combustion turbines, became a serious threat to the viability of vertically integrated utilities. They began to institute a wide range of cost-cutting measures and any programs that were placing an upward pressure on rates were eliminated or reduced in size. Many DSM programs, especially the ones that emphasized energy efficiency measures, fell in this category. Thus, DSM expenditures dropped dramatically as utilities geared up for competition.

Fourth Wave: Late 1990s

The fourth wave came in the late 1990s. Regulators were concerned that DSM expenditures were on the decline. They instituted a "public goods charge" to cover DSM expenditures. These were imposed as a charge on the sale of electricity by distribution utilities and had to be paid regardless of who was the ultimate power provider. DSM programs were administered by distribution utilities and often implemented by third-party energy service companies (ESCOs). Between 1989-99, utilities had spent a total of $14.7 billion on energy efficiency programs.

Fifth Wave: 2000 Onwards

The fifth wave began in the year 2000, and was triggered by price spikes in wholesale power markets. It got a boost in the year 2001, as California experienced a serious power crisis that spread quickly to cover all Western states. In this phase, there was widespread interest in implementing pricing reform rather than relying on traditional DSM programs. In particular, there was interest in dynamic pricing. This is a form of time-varying pricing that goes beyond static TOU pricing. Dynamic pricing is a form of pricing in which either the price for a period is unknown ahead of time, or the time when a known price will be called is unknown. It has been available to large customers for years, as real-time pricing (RTP). The digital revolution has now brought it to mass-market customers.

2.3 Lessons Learned

During the past three decades, DSM programs have had a significant impact on saving energy and scarce peaking capacity in the U.S. However, there is still a significant potential for saving energy. This potential can only be realized if the barriers that stand in the way can be overcome. One of these barriers is that actual savings often fall short of projections, creating a credibility problem for new programs. Another barrier is that free riders often join the program and are paid incentives even though they would have taken the same actions (e.g., purchase an efficient light bulb or air conditioner) even in the absence of the program. Finally, program costs often exceed expectations, rendering the programs cost-ineffective.

One of the key lessons learned from three decades of programmatic experience is that utilities will not implement DSM programs without an assurance of cost recovery, the availability of sales-revenue decoupling mechanisms and financial incentives for shareholders. In many situations, standards for appliances and building codes may be the cheapest way to achieve long-term efficiency gains.

Another lesson is that DSM can serve as a public policy tool to increase energy efficiency in restructured power markets if it is supported by a public goods charge on the distribution of electricity to cover costs of program implementation. However, if electricity is not priced properly to reflect the time variation in marginal costs, artificial financial incentives will be needed to support DSM. That approach is not sustainable over the long haul. Prices should reflect costs and be used to manage loads, since customers respond to dynamic pricing.
In the context of designing DSM programs, market pull strategies can play a key role.
It is important to create a self-sustaining process involving all members of the value chain, including the equipment manufacturer, wholesaler, retailer, installation and maintenance contractors and the end use customer. This process helps to transform the market infrastructure and is often referred to as market transformation.

Another lesson learned is that cash rebates should be used judiciously because of the huge expenses involved. Ultimately, they represent a transfer payment from non-participants to participants, since the cost of the rebates is going to be recovered from all customers. Evaluation studies have shown that rebates do influence customer participation rates in the short term.

Perhaps their best use is to stimulate market interest, and they can serve a catalytic function by jumpstarting the process. Rebates should not be included in a long-term portfolio.

While designing DSM programs, it is important to take a whole customer perspective. There are countless examples of DSM programs that failed because they focused on individual DSM measures, failed to understand the customer's perspective, and did not realize that people in different trades do not talk to each other.

It is important to distinguish new construction programs from those that involve retrofit applications. A "lost opportunity" is created when new buildings are developed with no thought about marginal energy costs. New construction programs ensure that new growth is energy efficient growth.

Building codes and appliance efficiency standards are a key part of a successful DSM portfolio and can be a powerful complement to utility activities. The state of California estimates that 2/3 of energy savings during the 1974-2000 period were due to codes and standards. Codes and standards have the broadest reach of any policy instrument and help transform the market infrastructure.

Finally, in the context of restructured power markets, it is important to note that the demand-side of the market has typically been neglected. This has been true in developed as well as developing countries. It is important that government agencies responsible for redesigning the market, including ministries and regulatory commissions, not neglect the role that can still be played by the electric utility in a restructured market. For example, the utility can design, implement and monitor the program while an independent contractor or government agency e does the program evaluation function. Alternatively, the utility can design the program and let someone else do the implementation. Or, finally, the utility can outsource the entire DSM function, inviting bids for portions of the DSM portfolio from various private sector organizations and act as a broker for DSM services to the customers.

2.4 Implications For Developing and Transition Countries

As part of the Johannesburg "Plan of Implementation," world leaders that had gathered at a summit on sustainable development in South Africa in the fall of 2002 made a commitment to removing market distortions by restructuring taxes and phasing out subsidies in energy markets.[9] It has committed to supporting efforts to improve the functioning, transparency and information about energy markets with respect to both supply and demand, with the aim of achieving greater stability and to ensure consumer access to energy services.

In the area of energy efficiency, the world leaders made a commitment to establishing domestic programs for energy efficiency with the support of the international community. This is expected to accelerate the development and dissemination of energy efficiency and energy conservation technologies, including the promotion of research and development.

[9] The "Plan of Implementation" was adopted at the World Summit on Sustainable Development in September 2002. This summit built on the framework that had been developed ten years earlier in Rio at the United Nations Conference on Environment and Development.

Utilities in developing and transition countries are often government-owned and insolvent. For instance, the typical utility in India and Pakistan, for example, only covers about 70 percent of its utility costs.[10] Revenue losses due to theft range between 20 to 40 percent.

There is a strong need for infrastructure investment in growing economies, but capital is scarce and often requires foreign exchange. It is estimated that India will need about 100 GW of new capacity over the next years, requiring a capital outlay of $120-160 billion.

One of the problems with subsidizing electricity prices is that it leads to over-consumption of electricity. In Pakistan, subsidies are estimated to represent 1 percent of GDP, and are a huge drain on the treasury. Subsidies contribute to the fiscal imbalance that is found in many developing and transition economies, in addition to making it less likely that consumers would invest in energy efficiency.

While privatization may provide a way out for many developing and transition countries, it is premature to think of privatization without ensuring that electricity is efficiently priced.

One way to implement self-sustaining tariffs is to allow prices to vary by time-of-day, since it does cost a lot more to serve peak loads than base loads. DSM provides a way for optimizing infrastructure investments, by ensuring that growth is efficient.

As developing and transition countries approach DSM, there are several pitfalls they should avoid. A case in point is the Dominican Republic, where poor customers pay a flat fee and there is no metering for a third of the customers. This essentially disengages a large portion of the market from the price mechanism for electricity. They have no incentive to use energy wisely or to reduce usage during peak times. When dealing with low to middle income customers, governments should not assume that customer demand will not be responsive to price. There is indeed evidence to the contrary, showing that when they have a tight budget, consumers tend to be more sensitive to price changes, especially in cases where expenses on a certain item make up a significant portion of their overall spending. For instance, in the Balkans, significant price response was observed when the sector was commercialized. In summary, people in all countries do respond to price signals. Restructuring and commercialization activities should be designed to maximize the opportunity of sending cost-reflective price signals to customers.

One of the recurring features of power markets in developing and transition economies is recurrent power shortages that expose customers to rotating blackouts and brownouts. Quantity-based rationing, such as that being carried out currently in China, ignores that different customers place a different value on electricity. A much better way is to implement time-varying rates that give customers the choice of buying peak power at a higher price or curtailing their usage if they do not want to pay the higher price.

China is in the process of reforming its power sector.[11] However, it appears that the government is interested in keeping the transition process smooth. It has placed a premium on price stability

[10] V. Ranganathan and D. Narasimha Rao, "Power Sector Reforms in India," *Management Review*, Volume 16, Number 1, March 2004.

over economic efficiency, and it does not want to be rushed to a new pricing structure. For example, Wang Mengkui, director of the power reform office at the State Council, has been quoted as saying, "We should moderately control the price during the initial stages of the bidding program to ensure a smooth transition to the new pricing mechanism."[12]

The consequence is that increasing power demand is creating electricity shortages and threatening the overall rate of economic growth when increase in electricity supply does not keep up with it. Factories have experienced production delays and rising electricity costs but are somewhat resilient because they can shift production to the middle of the night. However, retail businesses are less flexible. According to official sources, for each kWh that is not supplied, the economy loses 70 cents. This works out to a loss of $43.5 billion in China's GDP, since the power shortage this year amounts to 60 billion kWh.[13]

Recently, China has begun to implement price-based programs. TOU prices with large differences between peak and off-peak time periods have been implemented for large customers; interruptible tariffs that compensate customers for demand reductions during peak times have been introduced; and off-peak storage technologies like ice storage are being encouraged.[14]

Concern is sometimes voiced that time-varying price signals are likely to hurt the poor in society. However, there are intelligent methods for mitigating the impact on the poor. Two such methods include California's 20/20 program and Brazil's quota system based on bonuses/penalties. Additional methods are discussed in the concluding section of this Primer.

In the end, only those DSM programs should be implemented that are cost-effective from one of several perspectives. The key drivers of cost-efficacy are current and new electric rates, marginal costs, energy and demand impacts, and program costs. Trade-offs will have to be made between participants, utility, and society in designing the program. Results are likely to vary across regions and countries and also over time. A variety of tests for assessing cost-effectiveness are discussed in later in this report.

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[11] C. Zhang, *Reform of Chinese Electric Power Market: Economics and Institutions*, 2003, available at http://pesd.stanford.edu/docs/2003mtg_mrkt_rfm/China.pdf.
[12] http://ce.cei.gov.cn/enew/new_h1/fm00haq7.htm
[13] Matt Pottinger, "China sweats out power shortages," *The Wall Street Journal*, August 19, 2004.
[14] World Bank, "Demand-Side Management in China's Restructured Power Industry," unpublished report, August 2004.

Chapter 3 - Examples of Price-Responsive DSM Programs

This section surveys a new crop of DSM programs that emphasize price responsiveness, and are aimed at introducing a negative slope in the demand curve in order to let demand and supply balance out at a reasonable price of electricity during tight market conditions. This is not meant to suggest that there is no room for traditional DSM programs in developing and transition economies. They continue to be implemented, and a representative collection of such programs is described in a companion volume of case studies.

Programs involving demand response to price signals are not widely available in developing and transition economies at this time. Thus, the examples presented in this section come from developed economies. They fall into one of two categories:

- Load curtailment programs that pay the customer for reducing peak load during critical times

- Dynamic pricing programs that give customers an incentive to lower peak loads in order to reduce their electricity bills.

Both types of programs are largely designed to relieve peak capacity constraints but they could also be used to retain customers in a restructured market context.

3.1 Load Curtailment Programs

This sections focuses on load curtailment programs, while the next one discusses dynamic pricing programs. Load curtailment programs include traditional programs that are based on an up-front incentive payment and new market-based programs that involve a pay-for-performance incentive payment. The former include direct load control of residential air conditioners and water heaters, and curtailable and interruptible rates for commercial and industrial customers. The latter include programs that pay a certain amount of money for each MWh of electric load that is curtailed during critical time periods. These are sometimes also called demand bidding or buyback programs as well.

This section discusses the new crop of market-based programs. These programs introduce price responsiveness in restructured power markets and were developed in the aftermath of the California crisis. There are two types of market-based programs, one that deals with emergency situations by improving system reliability, and another one that deals with economic situations by mitigating the rise in wholesale prices. Full-scale programs of both types have been implemented in a variety of states, including California, New York, New England and Pennsylvania. The Canadian province of Ontario has implemented the emergency type of program. Programs of both categories are also operational in Australia and New Zealand.

Most commonly, these programs are implemented by the Independent System Operator (ISO, which is sometimes called the Independent Market Operator). The utilities can help in creating customer awareness. Energy service companies can act as aggregators that bid demand reductions during critical times. For this reason, they are sometimes also called curtailment service providers.

Large commercial and industrial customers are often the main participants in such programs. Sometimes, program participants include large multi-family dwellings. Program participants benefit if they have the flexibility in their business or technological processes to curtail peak loads during a few hours of the year. Some of them have cogeneration or stand-by generation that can be fired up on short notice for a few hours at a time.

Incentive payments are made to customers to induce them to reduce peak loads. Often times, the incentives are offered in two parts. The first part is a reservation payment expressed in dollars per kWh per month and the second part is expressed in dollars per MWh of load curtailed. The reservation payments are designed so that they would constitute less than 20 percent of the total incentive payment. In some variants, there is also a penalty for non-compliance. A pre-requisite for these programs is an agreed upon methodology for measuring customer base load (CBL), against which the curtailed amounts can be measured.[15]

In another variant of the program design, customers may bid "negawatts" of load reductions at pre-specified prices. It is not clear why these "demand bidding" programs have not proven very popular with customers. It is probably that customers do not have the time to systematically think about the financial opportunity created by demand bidding, since management focus is often diverted by higher priority issues dealing with running the business. It is also possible that customers are not certain their bids will actually be accepted.

The largest component of program cost is the incentive payment. Other elements of program cost include administrative costs associated with program management, some program evaluation cost and some marketing cost.

Experience with such programs indicates that it can be difficult to recruit customers into such programs even when the economic benefits are clear. Often, the programs have not been marketed well and thus failed to engage customers. One of the keys to success is the extent to which they are customer-friendly. They should explain in lay terms what the customer has to do in order to save money and what the risks are of not seeing those savings. If the savings look small in relation to day-to-day expenses and life priorities, it is hard to get the customer involved in the "distraction."

It is not enough to tell the customers that they should join the program because "it's the right thing to do!" Everyone knows demand response is a key part of the energy resource portfolio solution. Customers are suffering from information overload. They have become hardened to marketing. They are overwhelmed with too much information, and they just do not want to care anymore about what they should do.

One cannot expect customers to get "smarter." The ISOs and utilities have to position themselves as being the customer's partner in helping balance electricity demand with electricity

[15] E.g., in the state of New York, the CBL for a given hour is the average use during that hour on the five highest of the ten most recent like days.

supply in order to manage electricity costs. This concept of partnering has worked well in energy efficiency and should work well in load curtailment.

In the balance of this section, load curtailment programs in California and New York are surveyed.

3.1.1 Load Curtailment Programs in California

In June 2002, the California Public Utilities Commission (CPUC) initiated a proceeding on advanced metering, demand response (DR) and dynamic pricing.[16] This proceeding serves as a policymaking forum to develop price-driven DR as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. DR gives customers the ability to reduce or adjust their electric usage in a given time period, or shift that usage to another time period, in response to a price signal, a financial incentive, or an emergency signal.

The rulemaking proceeding is being conducted in coordination with the California Energy Commission (CEC) and the California Power Authority (CPA). Three working groups (WG) were formed to implement the proceeding, with WG1 dealing with policy issues, WG2 with large commercial and industrial customers (>200 kW demand) and WG3 with small customers (residential and small commercial and industrial customers with <200 kW demand). The primary focus is on dynamic pricing programs, such as critical-peak pricing and real-time pricing and contractual demand reduction. Traditional reliability-based emergency programs, such as interruptible rates and direct load control, were considered in a prior CPUC proceeding that is now closed.[17]

The WG1 vision statement sets a goal of reducing five percent of system peak demand by 2007 through price-based DR programs. The target for 2003 is 330 MW and it rises to 880 MW in 2004. The utilities are required to include these estimates in their procurement filings under R.01-10-024.

In 2001, the California Independent System Operator (ISO) implemented an emergency demand relief program that paid participating customers $20/kW-month of contractual capacity as a reservation payment during June through September and $500 for each curtailed MWh of energy. This program was called once that year, on July 3, 2001, and produced 162 MW of load relief. For customers who wanted the flexibility of saying “no” to a curtailment call, the ISO created another program that paid a lower incentive of $ 350/MWh and had no reservation payment for capacity relief. These emergency programs were discontinued when the state’s investor-owned utilities (i.e., the distribution companies), the CPUC, and the CPA began pursuing their own programs.

[16] CPUC R.02-06-001.
[17] Order Instituting Rulemaking, R.02-06-001, Policies and Practices for Advanced Metering, Demand Response and Dynamic Pricing, June 10, 2002, California Public Utilities Commission.

The ISO currently operates an ancillary services program directed at customers who are capable of moving large blocks of power. These customers, such as a rock crushing plant or a facility that could self-generate most of its power needs, are regarded as proxy generators, and given higher incentive payments.

The ISO has also recently instituted a voluntary load reduction program (VLRP). This program provides no financial incentive to the customer, and the amount of load they reduce is entirely up to them. This program helps the customer reduce the probability of incurring an involuntary load reduction. In addition, it gives them a leading position in their industry, since they can be held as a role model for their peers. The program is triggered when the ISO declares a Stage I alert. In 2001, a variety of voluntary load reduction programs were able to induce a drop of 5,000 MW (or 6 percent) in statewide peak load, significantly reducing the probability of outages.

The CPA manages a contracted demand reserves program. This five-year program began on July 1, 2002. It encourages businesses to reduce power usage when supplies are low. Between 500 and 1,000 megawatts of power are made available through the program. Participants are paid a monthly reservation fee for making a predetermined capacity amount available. When the state needs additional energy via reduced usage, participating businesses are notified up to 24 hours in advance that use will curtailed during a specific time period the next day. An Internet-based computer system records and monitors the reduction as it occurs and calculates the additional amount each business will be compensated for its actual reductions.

Key Issues

A key issue facing California is how to value the benefits of DR in a soft market characterized by excess capacity. Other key issues have to do with recruiting sufficient number of customers into the programs. The utilities have done extensive program marketing and it seems that a large number of customers are now aware of the DR programs. However, awareness and familiarity with the technical assistance programs are low. Participation rates very widely across programs and utilities. Through May 2004, close to 400 accounts (about 150 customers) are on demand bidding programs, of which 90 percent are in the service territory of Southern California Edison (accounting for about 60 MW of load). Only 45 accounts are on Critical Peak Pricing (CPP), (to be explained below in Section 3.2.2) of which 90 percent are in the service territory of Pacific Gas & Electric Company. The CPP participants stand to benefit without reducing their peak loads. Level of DBP participant commitment is uncertain.
Most non-participants cited inability to shift load as the major reason for declining to participate in the programs. Secondary factors included lack of financial motivation and uncertainty about the future state of the DR programs.

Awareness and interest levels are low for the transitional incentive programs. It is unclear whether this is due to low interest in the programs or a lack of familiarity with them. The programs may be perceived as carrying a high “hassle and risk” factor. Even enhanced automation that reduces power use during high-priced periods has had little uptake, despite coming with free site-specific services. In addition, it has been difficult to engage large customers who believe they know their load better than anyone.

The load curtailment programs are still fairly new and adoption takes time, as with any new product. However, there is fairly strong evidence that this crop of load curtailment programs may not make a major contribution to the state's ambitious overall DR goals.

3.1.2 Load Curtailment Programs in the Northeast

The New York, New England and PJM ISOs operate several load curtailment programs. In 2001, the New York ISOs emergency demand response program (EDRP) and day-ahead demand response program (DADRP) had a combined total of 308 participating customers who provided 450 MW of load relief against a signed-up capacity of 846 MW. It paid participants an average of $514 per MWh. The PJM programs had 50 participants in 2001 and provided 62 MW of load relief, against a capacity of 220 MW. The New England ISO had 101 participating customers who provided 14 MW of load relief, against a capacity of 63 MW. While most of these programs focus on large customers, the PJM has filed a program with FERC that would include non-hourly customers in mass markets.

The programs in New York have grown over time and include, besides the EDRP and DADRP programs, a program called Installed Capacity Special Case Resource (ICAPSCR). In the summer of 2003, the NYISO paid out $7.2 million in incentive payments to over 1,400 program participants, thereby reducing peak load by 700 MW. Two events were called that year, on August 15 and 16, following the blackout on August 14 that affected significant portions of the East Coast and the Midwest. The EDRP program had 1,323 participants, the largest number among all programs. The DADRP had 27 customers who were paid $100,000 to deliver 1,752 MWH of load relief. The ICAPSCR program had 213 customers with 815 MW of registered load. They were paid an average amount of $1.25 per kWh statewide; in load-congested areas like New York City, payments averaged $11.25 per kWh.

On August 15, 2003, New York's load curtailment programs are credited with providing reliability benefits of more than $50 million. On August 16, they are credited with providing an additional benefit of $3.5 million. Overall, the benefits created by these programs exceed their program costs by a factor of 7:1.

Postscript

While these load curtailment programs operate for only a few hours a year, they involve operating procedures and technologies that can be used year round. What needs to be explored is their possible use as complements to dynamic pricing programs discussed in the related case study. It may be possible to combine the technology and operational infrastructure that has been installed by customers to respond to the RTO/ISO programs with year round time-of-use and dynamic pricing signals from the local distribution company to expand the net benefits provided by the programs.

In 2001, the California Energy Commission conducted a pilot program that targeted Silicon Valley businesses. The program installed a portfolio of hardware and software technologies valued at $5 million in these businesses, including 1,000 pager-enabled automatic load controllers and interval meters for recording loads every 15 minutes. The program, approved by the California ISO as a demand relief program, has a potential for reducing 57 MW of peak load. However, only 6 MW actually enrolled in the ISO's program that year. The hardware and software infrastructure associated with this program can be used to respond to real-time pricing signals year round, once the state public utilities commission has authorized such signals.

A significant barrier to the design and management of programs offered by RTOs and ISOs is that these organizations are not set up to interact with hundreds, let alone thousands, of retail customers. They do not have the day-to-day relationship that the distribution companies have developed with these customers over a period of several years. One way to overcome this barrier is for a third-party to enter the market as a load aggregator. Such entry has been observed in the northeast. Another issue that bears on their success is the role of price caps in cannibalizing the benefits of load curtailment. In other words, the value of load curtailment is based on the avoided costs of not having that load, and that depends on the magnitude of wholesale market prices. If these prices are artificially capped, that reduces the value of load curtailment.

3.2 Dynamic Pricing Programs

Dynamic pricing programs are designed to lower system costs for utilities and bring down customer bills by raising prices during expensive hours and lowering them during inexpensive hours, as discussed further below. Their load shape objective is to reduce peak loads and/or shift load from peak to off-peak periods.

Such programs can be implemented at any stage of power sector reform. There are successful examples of power sectors that have not been deregulated and are served by vertically integrated electric utilities, and successful examples where the sector has been fully deregulated.

The electric utility is most often the primary party responsible for program design, implementation, evaluation and monitoring. Since these programs involve the implementation of new metering and billing systems, they are often conducted in close coordination with providers of such systems. In some cases, the programs involve the installation of end-use controlling equipment, such as smart, price-sensitive thermostats. Thus, they may involve the installers and manufacturers of such equipment.

Such programs can be targeted at any class of customer, ranging from the residential class to the commercial class to the industrial class. Most often, they begin with the industrial class of customers, and within a particular class they begin by targeting the largest customers.

The market implementation mechanism is the rate design itself. This is often accompanied by an educational campaign to inform customers about the benefits of dynamic pricing. In some cases, technical assistance may be provided to assist customers in benefiting from the incentives that are implicit in the rate design.

This section discusses several dynamic pricing programs, including time-of-use (TOU) pricing, critical-peak pricing (CPP) and real-time pricing (RTP). Brief definitions of these rates and some other related rates are provided below.

Time-of-Use Pricing (TOU). This rate design features prices that vary by time period, being higher in peak periods and lower in off-peak period. The simplest rate involves just two pricing periods, a peak period and an off-peak period. More complex rates also have one or more shoulder periods.

Critical Peak Pricing (CPP). This rate design layers a much higher critical peak price on top of TOU rates. The CPP is only used on a maximum number of days each year, the timing of which is unknown until a day ahead or perhaps even the day of a critical pricing day

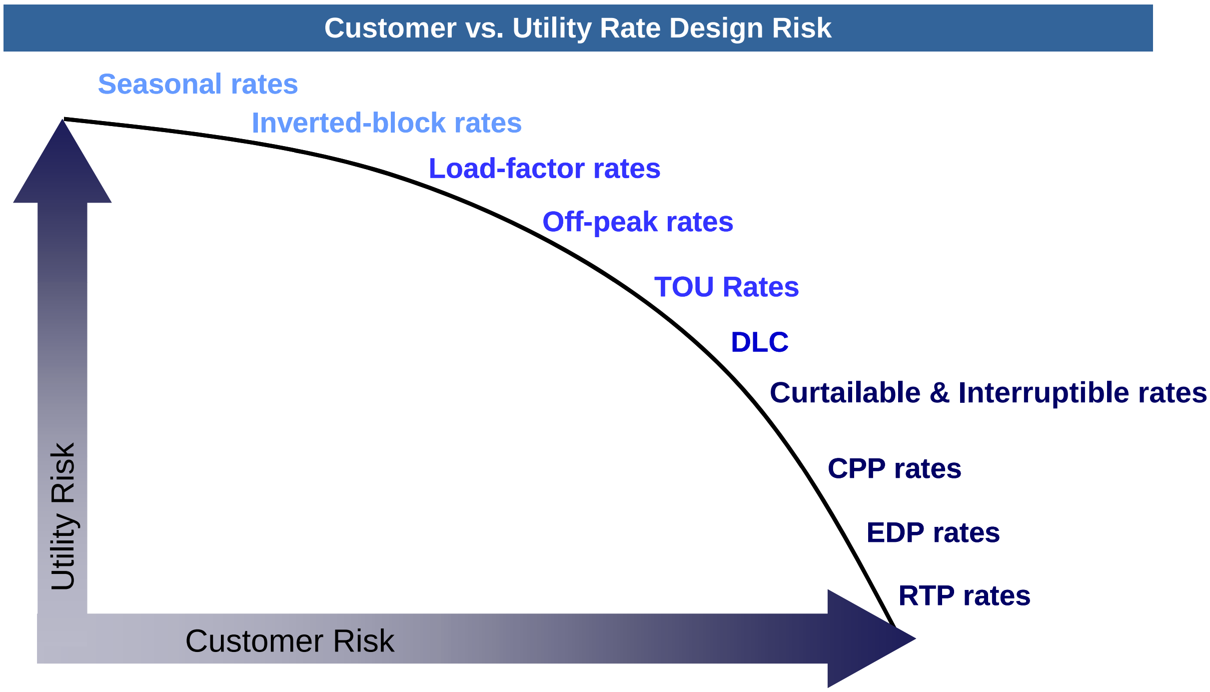
Extreme Day Pricing (EDP). This rate design is similar to CPP, except that the higher price is in effect for all 24 hours for a maximum number of critical days, the timing of which is unknown until a day ahead

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

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

Each of these rates exposes customers and utilities to varying amounts of risk. For example, RTP rates are riskiest from the customer's viewpoint since the utility simply passes through the wholesale costs to the customer. These rates have minimal risk to the utility. CPP rates carry less risk to the customer, since they know the prices ahead of time and the time for which these prices will be in effect is limited. The utility-customer risk trade-offs associated with the rates are show in Figure 3-1.

Figure 3-1
The Utility-Customer Risk Trade-Off Frontier



3.2.1 Time-Of-Use Pricing (TOU)

TOU pricing is commonplace in developed economies at all stages of market restructuring. Electricite de France (EDF) operates the most successful example of TOU pricing. Currently, a third of its population of 30 million customers is estimated to be on TOU pricing. This pricing design was first introduced for residential customers in 1965 on a voluntary basis, having been first applied in the country to large industrial customers as the Green Tariff in 1956.

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

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

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

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

PSE placed about 300,000 customers on the rate, but they could opt-out to the standard rate if they so desired. There was no additional charge to participate in the rate. The rate was designed to be "revenue neutral" for the average customer, i.e., if customers made no changes to their energy use patterns, their bill (and the utility's revenue) would stay unchanged. During the first year of the program, less than half of one percent elected to opt-out of the rate. Customer satisfaction with the rate was high. In focus groups, customers identified several benefits of the TOU rate besides bill savings, including greater control over their energy use; choice about which rate to be on; social responsibility; and energy security. PSE also provided a web site to customers where they could review their load shapes for the past seven days.

PSE had a rate case settlement in June 2002. Under the terms of the settlement, the program became an opt-in program for new customers. The peak/off-peak rate differential of the TOU rate was reduced from 14 mils to 12 mils per kWh.[18] A monthly fee of $1 a month, about 80 percent of the estimated variable cost of providing TOU meter reading, was levied on participating customers. Finally, each quarter PSE would notify customers of their savings (or losses) on the program, and it would switch all customers to the lower-cost rate (flat or TOU) in August 2003.

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

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

Media coverage was very negative and featured interviews with customers claiming that they had shifted as much almost half of their load from peak to off-peak periods, only to find out that they had lost money. Customers felt cheated, even though the amount of the loss for the average customer was 80 cents per month. PSE was left with no alternative but to pull the plug on a

[18] A mil is a thousandth of a dollar.

program that had become the most visible national symbol of a utility's commitment to time-varying pricing, and agreed to refund the increased amounts to participating customers.

Lessons Learned from the PSE TOU rate

Five lessons can be drawn from PSE's TOU program. First, customers do shift loads in response to a TOU price signal, even if the price signal is quite modest. According to an independent analysis, customers consistently lowered peak period usage by 5 percent per month over a 15-month period. Since PSE is a winter peaking utility, load reductions were somewhat higher in the winter months and somewhat lower in the summer months.

Second, it is important to manage customer expectations about bill savings. Third, customers should be educated on the magnitude of bill savings they can expect from specific load shifting activities. A variety of means can be used for providing this information to them, including letters, refrigerator magnets, a company web site that provides a listing of load shifting activities and associated savings estimates and a personal web site customers can consult for tracking their load shapes and savings.

Fourth**,** it is desirable to conduct a pilot program involving a few thousand customers before offering a rate to hundreds of thousands of customers. The pilot should allow before/after measurements on customers who get the rate treatments, as well as customers in a statistically representative control group. It should also feature multiple sets of TOU prices, rather than a single combination of prices, in order to allow estimation of demand curves for electricity use by TOU period. This information would allow the company to estimate the impact of future rates that are not included in the small pilot.

Finally, and most importantly, any program should make a majority of the customers better off, or it should not be offered.

Developing a TOU rate

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

The sidebar brings out the type of information that is needed to develop a TOU rate.

SIDEBAR 1
DEVELOPING A TOU RATE INVOLVES SEVERAL STEPS

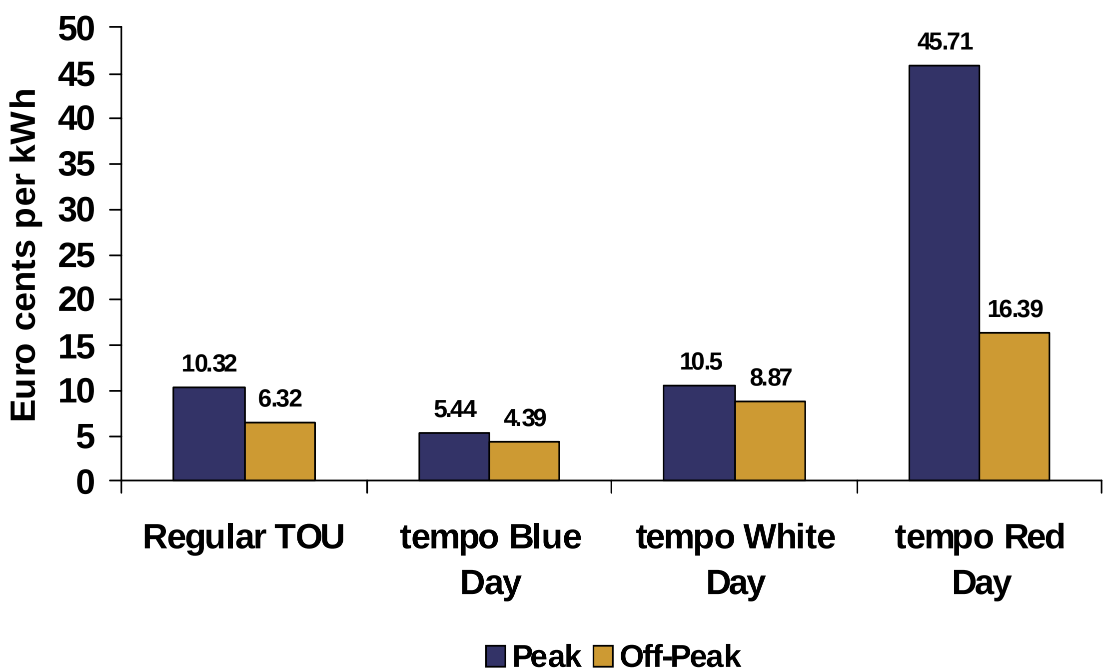
Existing Flat Rate	
Per-Customer Class Revenue Requirement	$ 100
Monthly Usage	1,000 kWh
Average Price	$ 0.10 /kWh
Revenue Neutral TOU Rate	
Estimate Peak Usage	200 kWh
Estimate Off-Peak Usage	800 kWh
Set Peak Price = Peak Marginal Cost	$ 0.2 /kWh
Set Off-Peak Price = Off-Peak Marginal Cost	$ 0.075 kWh
Given Class Revenue Requirement	$ 100
Given Monthly Usage	1,000 kWh
TOU Rate with Load Shifting	
Estimate Price Elasticity	-0.2
Estimate New Peak Usage	160 kWh[19]
Estimate New Off-Peak Usage	840 kWh
Estimate New Monthly Usage	1,000 kWh
Estimate New Monthly Bill	$ 95
Estimate Bill Savings = Revenue Loss	$ 100 – 95 = $5

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

3.2.2 Critical Peak Pricing (CPP)

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

Figure 3-2
EDF's *tempo* and standard TOU rates



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

- Consulting the Tempo Internet website: www.tempo.tm.fr
- Subscribing to an email service that alerts them of the colors to come
- Using Minitel (a data terminal particular to France, sometimes called a primitive form of Internet)

- Using a vocal system over the telephone
- Checking an electrical device (Compteur Electronique) provided by EDF that can be plugged into any electrical socket. A picture of this device appears at the end of the paper.

The tempo rate was preceded by a pilot program, in which prices were quite a bit higher than those that were ultimately implemented. The rates associated with the tempo program and with EDF's standard TOU rate are shown in Figure 3-2.

Critical Peak Pricing With Enabling Technologies

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

Two utilities, GPU in Pennsylvania and American Electric Power in Ohio, conducted small-scale pilot programs in the 1980s using a two-way communication and control technology called TransText. The TransText device allows for the creation of a fourth critical price period in which the retail price of electricity rises to a much higher level (e.g., 50¢/kWh in the GPU pilot). The number of hours during which this price can be charged is small (e.g., 100-200 hours) and the customer knows what the critical price will be ahead of time, but does not know when the price may be called.

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

The GPU experiment produced similar results, showing elasticities of substitution that ranged from -0.31 to -0.40, significantly higher than the elasticities associated with traditional TOU rates, which have averaged –0.14 in a range of studies.

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

Gulf Power is seeing results similar to those of the GPU experiment. Peak-period reductions in energy use over a two-year period have equaled roughly 22 percent compared with a control group, while reductions during critical-peak periods have equaled almost 42 percent. Diversified coincident peak demand reductions have exceeded more than 2 kW per customer. This voluntary program has been in place for less than a year, and Gulf Power has already signed up more than 3,000 high use customers. It hopes to attract 40,000 customers over the next 10 years, representing about 10 percent of the residential population. Participating customers pay roughly $5/month to help offset the additional cost of the communication and control equipment. In a recent survey, the program received a 96 percent satisfaction rating.

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

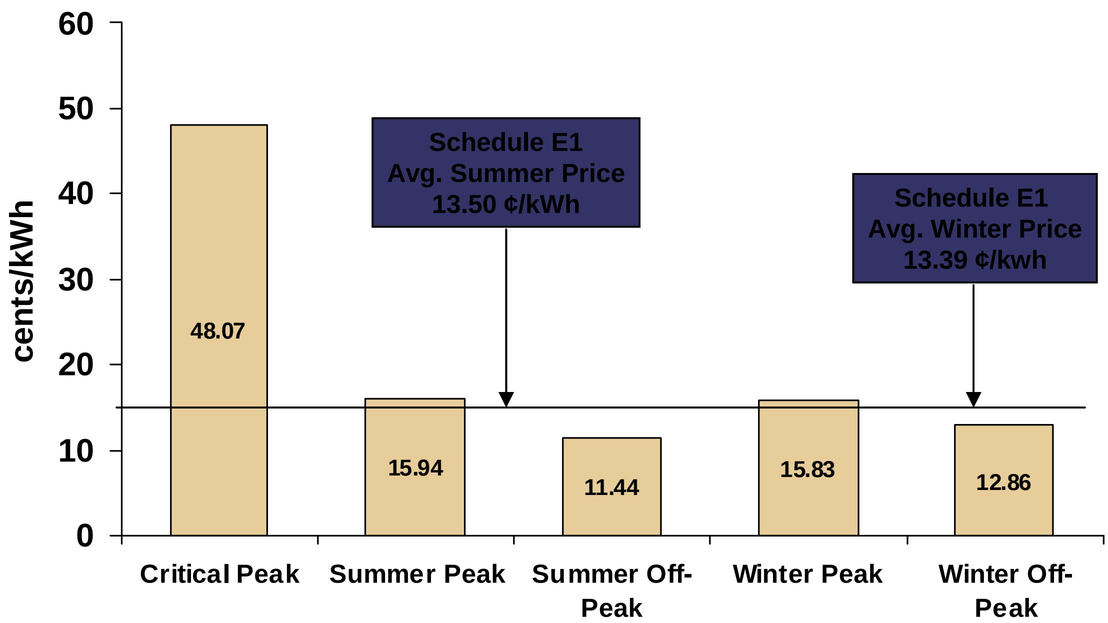
California's Pricing Experiment

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

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

Figure 3-3 shows the CPP tariffs that are being used in the California experiment.

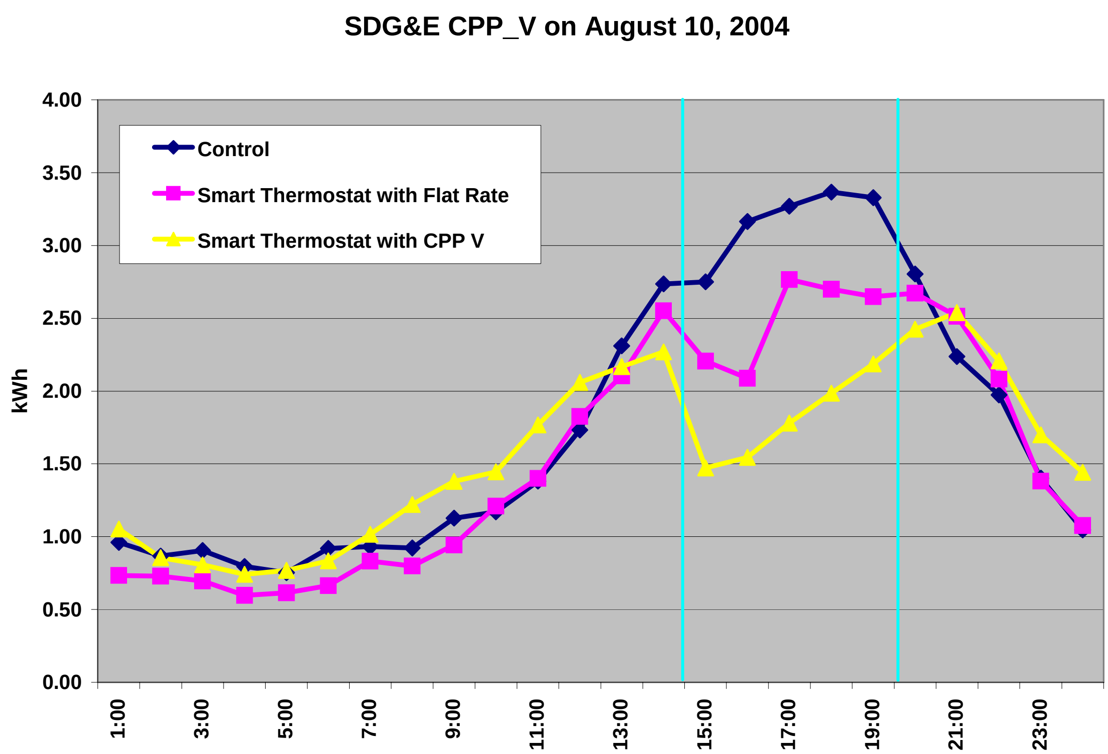
Figure 3-3
Critical-peak pricing (CPP) tariff



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

Figure 3-4 shows the changes in customer load shapes caused by the CPP tariff in customers who were located in the San Diego Gas and Electric service area. The black line shows the usage of the control group of customers. The grey line shows the usage of customers who were equipped with a smart thermostat that received a communication signal from the utility during critical hours, which raised the set point of the thermostat. Their tariff was unchanged from that of the control group. The difference between the two lines is noticeable and suggests that remotely controlling the thermostat lowers peak usage. The white line shows the usage of customers who were equipped with a smart thermostat and who also were placed on the CPP tariff. They show a greater drop than customers who had the smart thermostat but who were not placed on the smart thermostat.

Figure 3-4
Changes in Customer Load Shapes



3.2.3 Real-Time Pricing (RTP) for Residential Customers

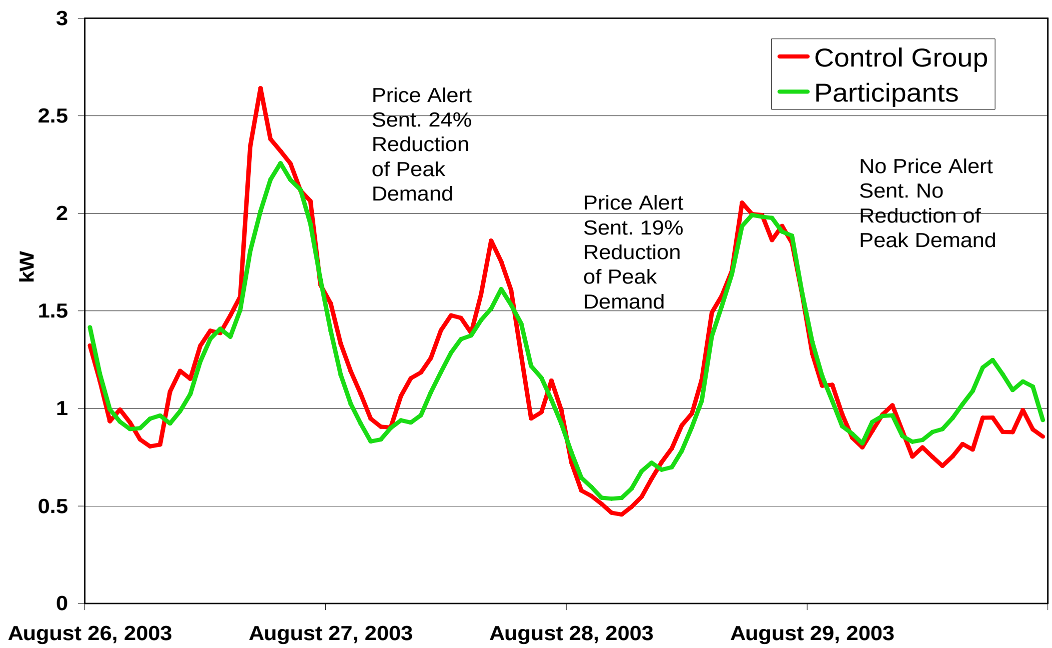
The Chicago Community Energy Cooperative (Co-op) has implemented a market-based RTP pricing plan for residential customers, in conjunction with the local electric utility, CommEd. The utility provides the rate and the metering/billing system while the Co-op provides customer notification (via a Web site,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

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

In the first year of the program, 750 customers were enrolled. Of these, 100 are in a control group. The summer of 2003 was mild in terms of both temperatures and prices. For example, the number of days with a maximum temperature higher than 90 degrees was 10 versus a historical average of 18. The maximum price was 12.39 cents/kWh, versus a price of 38.11 cents/kWh during the crisis years of 2000-02.

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

Figure 3-5
Impact of RTP on Chicago Residences



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

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

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

3.2.4 Real-Time Pricing (RTP) for commercial and industrial customers.

Utilities in the southeastern U.S. have implemented RTP rates for about 2,000 customers on a day-ahead or hour-ahead basis. These companies include Georgia Power, Duke Power and the Tennessee Valley Authority. The Georgia Power program is discussed in detail below.

Before describing the Georgia Power program, we note that RTP rates are also used by ESKOM, the state-owned utility in South Africa, for its largest customers, including the fabled gold mines. ESKOM has 1,400 MW of load on day-ahead RTP. These customers drop their load by 350-400 MW for up to three consecutive hours when faced with high prices. While RTP is set up on a day-ahead basis, customer response is not used to optimize the dispatch of the power system. Electricity prices are based on the Pool Output Price, and do not change in response to changes in customer demand that may be induced by RTP. The utility is not aggressively marketing the program for this reason. It hopes that once a competitive energy market has been created, with a functioning Power Exchange, RTP will then be able to play its proper role in system operations.

If RTP had been implemented in California during the summer of 2000, much of the power crisis that developed in May 2000 would have abated within a month, rather than persisting for a year. If only a small proportion of the total customers had bought power on RTP, statewide peak demand would have dropped by 2.5 percent, or 1,250 MW. During the peak hours, this would have lowered wholesale market prices by 20 percent. The state's power costs for the summer would have dropped by 6 percent.[20]

RTP at Georgia Power

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

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

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[20] Faruqui, Ahmad, Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, "Getting out of the Dark," *Regulation*, Fall 2001, pp. 58-62.

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

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

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

Setting the Customer Baseline. When Georgia Power began its RTP program, it based a customer's baseline usage, or CBL, on an 8,760-point hourly load profile. However, customers often found this CBL confusing, and therefore frustrating. In response to these customers, Georgia Power now offers 360-point CBLs (with 24 average hourly weekday loads per month and six average 4-hour weekend day loads, for a total of 30 CBL points per month), and two-point CBLs. The two-point CBLs simply average usage levels during the peak and off-peak periods.

The majority of customers (basically, the high-load-factor customers) now select the two-point CBL. If the two-point CBL does not seem appropriate based on a customer's usage profile, Georgia Power will usually use a 360-point CBL. Only a very few "unique loads" use the 8,760-point CBL today.[21]

[21] Our source noted that customers who can "really respond a lot" are typically on the higher point CBLs.

Price Protection Products. Georgia Power offers customers a variety of products that allow customers to influence their exposure to RTP price risk. One product, the adjustable CBL, allows customers to temporarily adjust their CBLs. For example, if customers want to lower their exposure to price volatility, they would increase CBLs. (Customers wanting to raise their CBLs must be on the RTP rate for a year, so that Georgia Power can determine how high the CBL can be raised.) Customers wanting to expose more loads to real-time prices—presumably because they believe it will be a cool summer—can lower their CBLs. Of the roughly 1,650 customers on RTP, 600 currently have adjustable CBLs. About 60 percent of the incremental energy sold on the RTP rate (i.e., usage above baseline) is now protected by this product.

Georgia Power also offers a variety of financial products to limit customers' exposure to RTP price volatility. These products include price caps, contracts for differences, collars, index swaps, and index caps.[22] Georgia Power has sold these Price Protection Products, or PPPs, for three years. It currently has 250 contracts with about 90 customers. (Customers have multiple contracts to cover different time periods.) Georgia Power believes that offering these products has probably not increased the number of customers on the RTP program, but it has increased customer satisfaction. The utility has examined whether offering the PPPs has dampened price responsiveness, and has found no evidence of this.

Lessons Learned. Our research shows that Georgia Power's experience highlights a number of lessons that have also been seen at other utilities. First, RTP can deliver substantial peak savings, despite the fact that many customers are not very responsive to price. When the hourly price reached $6.40/kWh, Georgia Power saw 850 MW of load reduction (out of 1,500 – 2,000 MW of incremental, or above-baseline load) from its RTP customers. Georgia Power also believes that customers have responded to the availability of low off-peak prices by expanding their facilities and business operations in Georgia. In other words, the rate has served to bring economic growth to the state and been a form of strategic electrification while also being a form of load management.

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

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

Georgia Power has also found that manufacturers with highly energy-intensive processes, such as chemical and pulp and paper companies, are generally the most price responsive customers. It

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[22] Georgia Power's price-cap product guarantees that average RTP prices over a specific time period will not go above the cap. Its contract for differences gives a fixed price guarantee on the average RTP price. The collar has a cap and floor on the average RTP price over a specific time period. The index swap is a financial agreement that ties the RTP price to a commodity price index. If the commodity price index increases, so does the RTP price. If it decreases, so does the RTP price. The index cap is a financial agreement that ties an RTP price cap to a commodity price index. As the commodity price increases or decreases, so does the price cap.

also learned that some commercial customers would respond to price. Office buildings, universities, grocery stores, and even a hospital (that changes chiller use based on hourly prices) are all responsive to real-time pricing.

Georgia Power states that the major lesson it has learned is that education is the key to a successful RTP program: Customers understand RTP the first time it is explained to them, but the utility needs to go back in a year or two and review the program with them. There are a couple of reasons for this: First, there is always turnover in staff. Second, customers tend to just "ride" the rate during a period of low prices, and then begin to pay attention to it again when prices increase. Georgia Power now holds annual, statewide meetings with all its customers to keep them informed about the RTP program. The meetings are well attended, and the utility believes its education program has paid off in customer satisfaction.

3.3 Customer Response to Dynamic Pricing Programs

As brought out in the next section, a primary driver in assessing the cost-effectiveness of dynamic pricing programs is the response of customers to such programs. This can be expressed as the change in customer load shape that occurs across the 24 hours of a peak day. Analytically, it is useful to decompose this change in load shape into two effects. The first effect is a pure change in the shape of the curve, with energy consumption during the day, as represented by the area under the curve, being held constant. This arises from the customer's decision to substitute lower-cost off peak electricity consumption for higher cost peak consumption. The second effect is a change in the level of consumption, which arises from the customer's decision to lower (or raise) electricity consumption as a whole in response to a rise (or fall) in its price compared to the price of other goods and services.

It is customary to measure these two effects by two parameters that are called elasticities. One is the elasticity of substitution and the other is the price elasticity of (overall) electricity consumption. The elasticity of substitution measures the rate at which the customer substitutes off-peak electricity consumption for peak usage in response to a change in the ratio of peak to off-peak prices. The latter measures the rate at which the customer changes overall electricity consumption in response to a change in the daily price of electricity, which can be expected to change as peak prices rise and off-peak prices fall. Both elasticities are negative and often very small in value but in the presence of sharply higher prices during peak periods on selected days, they can still produce substantial reductions in peak energy consumption.

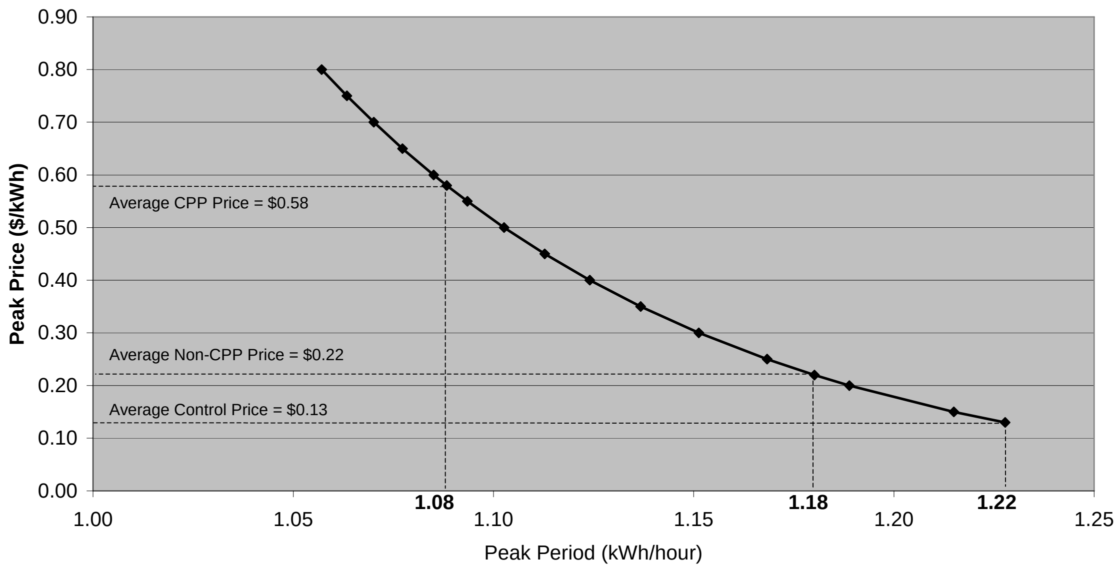
Table 3-1 presents recent estimates of these two elasticities and associated impacts on peak electricity consumption (where available) for two types of dynamic pricing rates, critical-peak pricing (CPP) and real-time pricing (RTP). It is based on a number of recent studies that are cited below the table. The reader may wish to consult other surveys of the elasticity literature to obtain additional perspectives. Several earlier studies are cited in Chris S. King and Sanjoy Chatterjee (2003) and Ahmad Faruqui et al. (1991).

Table 3-1 Elasticities and Impacts Associated with Dynamic Pricing						
Rate	Technology	Region	Segment	Elasticity of Substitution	Overall Price Elasticity	Impact on Peak-Period Electricity Consumption
CPP*	None	California	Residential	-0.09	-0.03	-14%
CPP	Smart thermostat	California	Residential	-0.08	-0.04	-27% (Two-thirds from technology)
CPP	None	California	Small commercial and industrial (<200 kW)	Not available	Not available	-6% to –9%
CPP	Smart thermostat	California	Small commercial and industrial (< 200 kW)	-0.02	Not available	-14% (More than 80% from technology)
RTP*	None	Georgia	Large commercial	0 to –0.53 (avg. 0.21)	Not available	-17%
RTP	None	Georgia	Large industrial	0 to –0.31 (avg. –0.18)	Not available	-17%
RTP	None	England & Wales (E&W), East U.S.	Pulp and Paper Manufacturing	-0.15	Not available	Not available
RTP	Self-Generation	E & W, East U.S.	Pulp and Paper Manufacturing	-0.30	Not available	Not available
RTP	None	E & W, East U.S.	Non-Electric Intensive Manufacturing	-0.04	Not available	Not available
RTP	Self-Generation	E & W, East U.S.	Non-Electric Intensive Manufacturing	-0.07	Not available	Not available
RTP	None	New York	Large commercial (> 2 MW)	0	Not available	Not available
RTP	None	New York	Large government/educational (>2 MW)	-0.30	Not available	Not available
RTP	None	New York	Large industrial (> 2 MW)	-0.11	Not available	Not available

*CPP refers to Critical-peak pricing; RTP refers to Real-time pricing.
Sources: Steven Braithwait and David Armstrong, "Potential Impact of Real-Time Pricing in California," California Energy Commission, January 14, 2004; Charles River Associates, *Impact Evaluation of the California Statewide Pricing Pilot: Final Report*, February 11, 2005; Christensen Associates, "Electricity Customer Price Responsiveness—Literature Review of Customer Demand Modeling and Price Elasticities," California Energy Commission, September 29, 2000; Charles Goldman, Catherine McDonough and Bernie Neenan, "Does RTP deliver Demand Response? Case Study of Niagra Mohawk's RTP Tariff," EPRI, *2004 AESP/EPRI Electricity Pricing Conference: What's Working and What's Needed*, Report Number 1008530, 2004.

Often, demand curves are used to show how customers change their electricity consumption by time period in response to changing prices. The demand curve in Figure 3-6 shows how energy use in the peak period varies with peak-period price, other things equal. It is based on analysis carried out with residential customers in California. The curve shows the combined impact of the elasticity of substitution and the price elasticity of overall electricity consumption. By convention, a number of factors are held constant along the curve. These include weather, the saturation of air conditioning and the off-peak price. If any of these factors change, the demand curve will shift to the left or right, depending upon the nature of the change in the underlying factors.

Figure 3-6
Peak Period Demand Curve



The demand curve shows that at a price of 13 cents/kWh, electricity use is 1.22 kWh/hour during the peak period that spanned the hours from 2 pm to 7 pm on weekdays that were not holidays. At a price of 22 cents/kWh, electricity consumption falls to 1.18 kWh/hr.

One way of summarizing price impacts when price changes are large is the arc elasticity. Arc elasticity equals the percentage change in energy use relative to the average of the new and old values for both quantity and price, as depicted in the following equation:

$$\text{Arc Elasticity} = [(Q_2 - Q_1) \div (Q_2 + Q_1)/2] \div [(P_2 - P_1) \div (P_2 + P_1)/2].$$

In the example, a rise in the price of 51.43% produces a drop in electricity use of 3.33%, yielding an implicit arc own-price elasticity of demand of -0.065 (= -3.33%/+51.43%). When the price increases to 58 cents/kWh, corresponding to the average CPP peak-period price on CPP days, demand falls to 1.08 kWh/hr. Thus, a rise in the price of 126% from the initial average value of 35 cents/kWh produces a drop in electricity use of 12%, yielding an implicit arc own-price elasticity of demand of –0.096.

Figure 3-7 shows the demand curve for off-peak electricity use. It shows that a reduction in the price of off-peak electricity from the control group value of 13 cents/kWh to an average off-peak price on CPP days of 9 cents/kWh increases hourly energy use from 0.783 kWh to 0.798 kWh. That is, a 36 percent decrease in price induces a rise in demand of 2%, yielding an implicit arc own-price elasticity of off-peak demand of -0.05, a value slightly higher than that observed for peak period usage for the Non-CPP rate.

Figure 3-7
Off-Peak Period Demand Curve

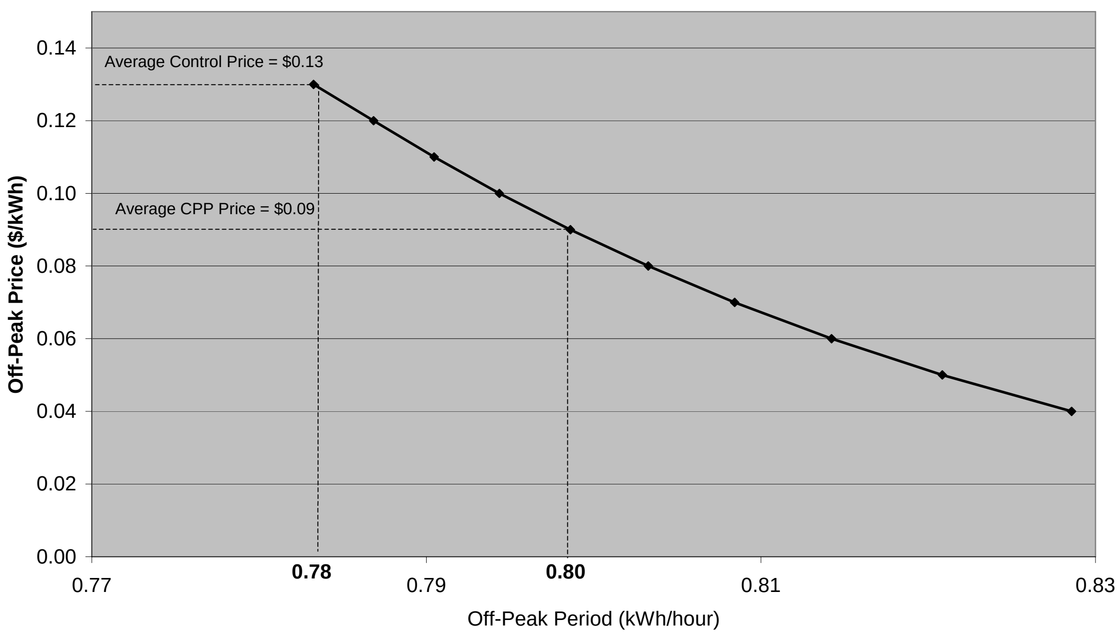


Figure 3-8 shows the influence of central air-conditioning on the demand curve for peak-period electricity use. The demand curve for customers without central air-conditioning has a much steeper slope than the average statewide demand curve, indicating a lower degree of price responsiveness. For customers with central air-conditioning, the demand curve is more flat indicating that as the saturation of central air-conditioning increases, price responsiveness also increases.

Figure 3-8
Peak Period Demand Curves, Default and CAC Variations, California

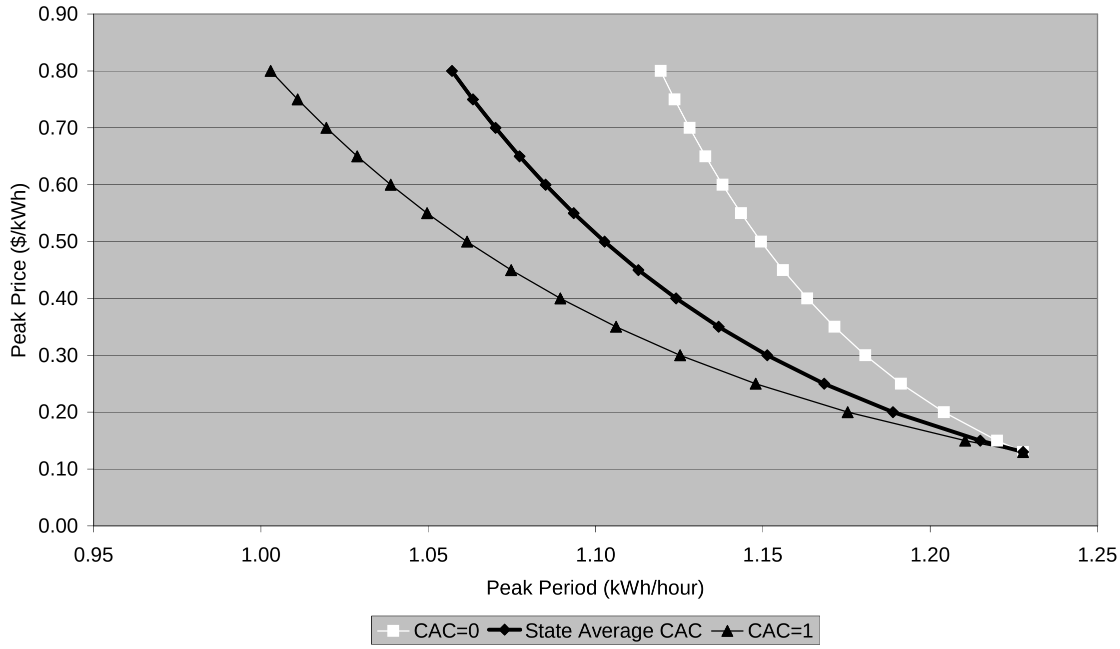
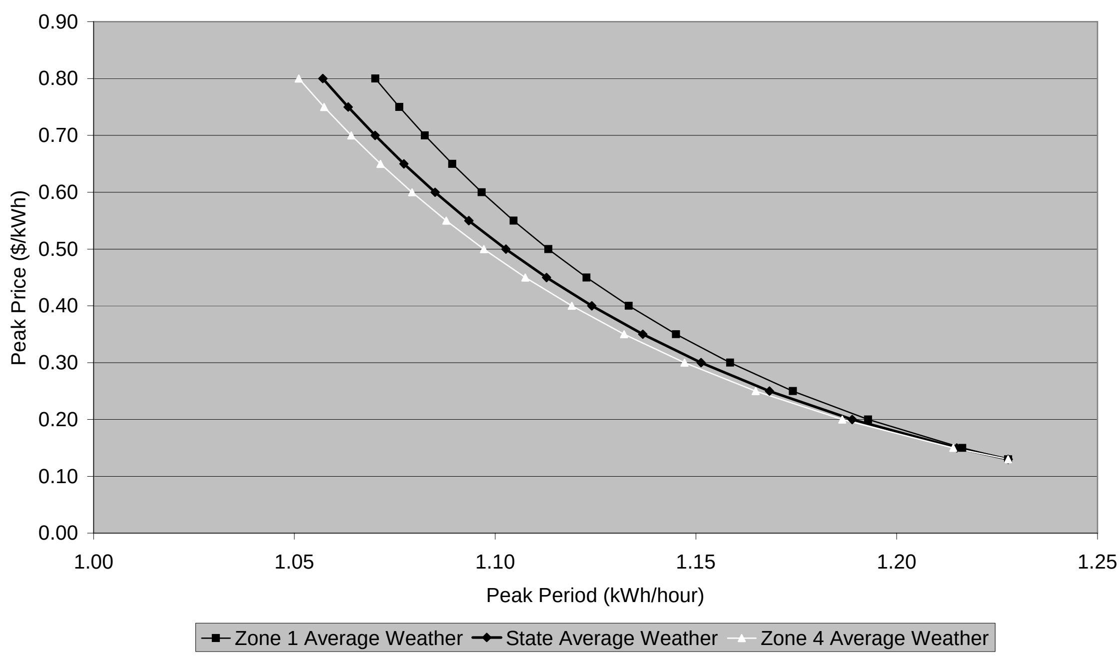


Figure 3-9 shows the influence of weather on the slope of the demand curve. Hotter weather conditions produce a slightly flatter, more price-responsive demand curve, and cooler weather conditions produce a slightly steeper, less price-responsive demand curve.

Figure 3-9
Peak Period Demand Curves, Default and Weather Variations



Chapter 4 - Evaluating the Cost-Effectiveness of DSM Programs

Supply-side programs, such as investing in new peaking capacity, are evaluated by measuring their impact on utility revenue requirements. If the program reduces revenue requirements, it is worth doing because the program will lower the average customer's bill without impairing the utility's finances.

DSM programs, such as dynamic pricing and incentive-based load curtailment programs, can also be evaluated for their impact on utility revenue requirements. Since revenue requirements are synonymous with the utility's cost of doing business, a cost-benefit test for assessing demand-side programs is called the Utility Cost (UC) test.[23] However, this test provides only one perspective for evaluating demand-side programs. Several other perspectives are of interest and these have been codified in the California Standard Practice Manual (SPM).

It is appropriate to make a historical comment about the evolution of this manual, since it has been widely adopted throughout the US and abroad. It was the first such document to provide official guidelines existed for utility-sponsored programs. The first edition was issued in February 1983, entitled the *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs*. One year later, an informal appendix was adopted that identified cost-effectiveness procedures for an "All Ratepayers" test. At that time, the manual identified five perspectives for assessing DSM programs—participants, non-participants, all ratepayers, society, and the utility. These five perspectives have continued to be relevant ever since.

The SPM was revised again in 1987.[24] The primary changes (relative to the 1983 edition), were: (1) the renaming of the "Non-Participant Test" to the "Ratepayer Impact Test," (2) renaming the All-Ratepayer Test to the "Total Resource Cost Test," (3) treating the "Societal Test" as a variant of the "Total Resource Cost Test," and (4) including an expanded explanation of "demand-side" activities that should be subjected to standard procedures of benefit-cost analysis.

The most recent edition of the SPM was issued in 2001. This edition was prompted by the cumulative effects of changes in the electric and natural gas industries and a variety of changes in California statute related to these changes. As part of the major electric industry restructuring legislation of 1996 (AB1890), for example, a public goods charge was established that ensured minimum funding levels for "cost effective conservation and energy efficiency" for the 1998-2002 period, and then (in 2000) extended through the year 2011. Additional legislation in 2000 (AB1002) established a natural gas surcharge for similar purposes. Later in that year, the Energy

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[23] Once the utility industry began to be restructured in the mid-nineties, it was no longer obvious that the utility would be the sole organization responsible for implementing demand-side programs. Program Administrators could come into being that would implement such programs. Thus, this test was relabeled the Program Administrator Test. However, in most cases, the utility continues to be body responsible for implementing such programs. This is especially true for dynamic pricing programs. Thus, we continue to refer to the test by its original name, the Utility Cost test.

[24] California Public Utilities Commission and California Energy Commission, *Standard Practice Manual: Economic Analysis of Demand-Side Management Programs*, December 1987.

Security and Reliability Act of 2000 (AB970) directed the California Public Utilities Commission to establish, by the spring of 2001, a distribution charge to provide revenues for a self-generation program and a directive to consider changes to cost-effectiveness methods to better account for reliability concerns.

In the current edition, the "Utility Cost Test" is renamed the "Program Administrator Test" to include the assessment of programs managed by other agencies. Second, a definition of self-generation as a type of "demand-side" activity is included. Third, the description of the various potential elements of "externalities" in the Societal version of the TRC test is expanded. Finally the limitations section outlines the scope of this manual and elaborates upon the processes traditionally instituted by implementing agencies to adopt values for these externalities and to adopt the policy rules that accompany the SPM.

4.1 Introduction to the Cost-Effectiveness Tests

The primary test that is used for screening DSM programs is **the Total Resource Cost** Test (TRC). This test assesses whether or not the program improves economic efficiency in the broad sense of the term. It compares the benefits of the programs to society with the costs to society of implementing the program. The benefits include the avoided cost of capacity and energy while the costs include the equipment and administrative costs involved in executing the program.[25] The administrative costs include staff time and other costs that are necessary to design, implement, monitor and evaluate the program impacts. The test excludes any transfer payments between members of the society. Thus, incentive payments by the utility to recruit customers and taxes (of all kinds) that are paid by either the utility or the customer are excluded from the calculation.

The TRC test is most appropriate for use by the Energy ministry in developing and transition countries. A variant of the test that allows for the inclusion of externalities associated with power production and delivery is often used as an adjunct to the TRC test. It is often called the Societal Test and is suitable for use by the Environment ministries in developing and transition countries.

The TRC test defines a necessary condition that needs to be met before a program can be judged as being worthy of implementation. If the program passes the TRC test, it is likely to improve economic efficiency. However, the program may have distributional impacts that may be adverse to important groups. Thus, just because a program passes the TRC test does not mean it should automatically be implemented. The TRC test does not represent a sufficient condition. Other tests that address these distributional issues, such as the impact on rates for all customers and the impact on utility earnings, need to be factored into the final decision to proceed or not to proceed with the program. These other tests include the UC test discussed earlier, and the Participant (P) and Rate Impact Measure (RIM) tests.

[25] It is unclear whether sales tax on the equipment that is avoided should be included in the measure of avoided capacity costs, since by definition sales tax is a transfer payment between groups within society and the TRC calculation is devoid of all transfer payments.

The **UC** test measures benefits using the same measures that are included in the TRC test. On the cost side, it counts utility expenditures for running the program, including marketing expenses, incentive payments and any other costs, such as those for program administration.

The **P test** measure the impact of the program on the participating customers by measuring the change in their monthly electric bills and by adding applicable incentive payments and subtracting participation fees and equipment costs incurred by customers.
If a program fails the P test, it is a moot issue whether or not it should be offered to anyone. In that sense, the P test is another necessary but insufficient condition for a program to be offered.

The **RIM** test measures the impact of the program on average rates. On the benefit side, it includes the same measures as are included in the TRC and UC tests. On the cost side, it includes all the measures that are included in the UC test and additionally includes lost revenues from the program. Lost revenues are the same as the change in customer bills, which are measured in the P test.

If a program fails the RIM test, it will require an increase in utility rates in order to not adversely affect utility earnings. If it passes the RIM test, rates can be lowered without impairing utility earnings. In the TOU rate example discussed earlier in Section 3.2.1, the program passed the TRC test but failed the RIM test. It reduced avoided supply-side costs by $5 but raised metering costs by $1. Thus, it had TRC benefits of $4. In addition, it lowered customer bills by $5 and so it lowered revenues by the same amount. Thus, the benefit on the RIM test is -$1 (=$4 -$5).

A program that passes all the tests is indeed a win-win program. There is no reason why such programs should not be implemented. Such a situation will happen if the utility's rates are lower than its marginal energy costs and if the marginal program costs are lower than the marginal energy costs. The program will lower overall resource costs and lower rates as well. It will also lower customer bills and the utility's revenue requirements.

However, most programs will pass one or two tests and fail the others. Trade-offs will then have to be made between the competing objectives of DSM programs. For example, the program may pass the TRC test and fail the RIM test. This often happens with energy efficiency programs being offered by utilities whose rates are higher than their marginal energy costs. The marginal program cost of some of these programs will be less than the marginal cost of energy and they will pass the TRC test. But since rates are higher than marginal energy costs, they will create lost revenues and require the average rate level to be raised for all customers. That may still be worth doing, if the objective of improving economic efficiency is given sufficient weight in the government's policy making.

In some cases, a program may fail the TRC test but pass the Societal version of the test that includes an allowance for externalities. In such cases, the Environment ministry may wish to pursue the program but the Energy and Finance ministries may not wish to pursue it. Such situations call for policy makers to make their value judgments explicit and to develop rules for making trade-offs between conflicting objectives. Research has found that DSM programs can have positive and significant impacts on environmental quality. A recent analysis of DSM impacts in the US has estimated they can help reduce carbon emissions by 32 million tons in 2010, growing to over 115 million tons by 2030.[26]

4.2 Demand-Side Management Categories and Program Definitions[27]

One important aspect of establishing standardized procedures for cost-effectiveness evaluations is the development and use of consistent definitions of categories, programs, and program elements.

The SPM employs the use of general program categories that distinguish between different types of DSM programs, including energy conservation, load management, fuel substitution, load building, and self-generation programs. Conservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year. ‘Conservation’ in this context includes all ‘energy efficiency improvements’. An energy efficiency improvement can be defined as reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting level per square foot. Load management programs may either reduce electricity peak demand or shift demand from on peak to non-peak periods.

Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building). Self generation refers to distributed generation (DG) installed on the customer’s side of the electric utility meter, which serves some or all of the customer’s electric load, that otherwise would have been provided by the central electric grid.

In some cases, self generation products are applied in a combined heat and power manner, in which case the heat produced by the self generation product is used on site to provide some or all of the customer’s thermal needs. Self-generation technologies include, but are not limited to, photovoltaics, wind turbines, fuel cells, microturbines, small gas-fired turbines, and gas-fired internal combustion engines.

Fuel substitution and load building programs were relatively new to DSM in California in the late 1980s, born out of the convergence of several factors that translated into average rates that substantially exceeded marginal costs. Proposals by utilities to implement programs that increase sales had prompted the need for additional procedures for estimating program cost effectiveness. These procedures may be applicable in a new context. Assembly Bill 970 amended the Public Utilities Code and provided the motivation to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and

[26] Ahmad Faruqui, Greg Wikler and Ingrid Bran, “The Long View of Demand-Side Management Programs,” in Michael A. Crew and Joseph C. Schuh, *Markets, Pricing, and Deregulation of Utilities*, Kluwer Academic Publishers, 2003.
[27] This section is extracted from the 2001 edition of the Standard Practice Manual.

self-generation. Hence, self-generation was also added to the list of DSM programs for cost-effectiveness evaluation. In some cases, self-generation programs installed with incremental load are also included since the definition of self-generation is not necessarily confined to projects that reduce electric load on the grid. For example, suppose an industrial customer installs a new facility with a peak consumption of 1.5 MW, with an integrated on-site 1.0 MW gas fired DG unit. The net impact of the new facility is ***load building*** since the new facility can draw up to 0.5 MW from the grid, even though the DG unit has displaced 1 MW of load. The proper characterization of each type of DSM program is essential to ensure the proper treatment of inputs and the appropriate interpretation of cost-effectiveness results.

Categorizing programs is important because in many cases the same specific device can and should be evaluated in more than one category. For example, the promotion of an electric heat pump can and should be treated as part of a conservation program if the device is installed in lieu of a less efficient electric resistance heater. If the incentive induces the installation of an electric heat pump instead of gas space heating, however, the program needs to be considered and evaluated as a fuel substitution program. Similarly, natural gas-fired self-generation, as well as self-generation units using other non-renewable fossil fuels, must be treated as fuel-substitution. In common with other types of fuel-substitution, any costs of gas transmission and distribution, and environmental externalities, must be accounted for. In addition, cost-effectiveness analyses of self-generation should account for utility interconnection costs. Similarly, a thermal energy storage device should be treated as a load management program when the predominant effect is to shift load. If the acceptance of a utility incentive by the customer to install the energy storage device is a decisive aspect of the customer's decision to remain an electric utility customer (i.e., to reject or defer the option of installing a gas-fired cogeneration system), then the predominant effect of the thermal energy storage device has been to substitute electricity service for the natural gas service that would have occurred in the absence of the program.

In addition to Fuel Substitution and Load Building Programs, recent utility program proposals have included reference to "load retention," "sales retention," "market retention," or "customer retention" programs. In most cases, the effect of such programs is identical to either a Fuel Substitution or a Load Building program — sales of one fuel are increased relative to sales without the program. A case may be made, however, for defining a separate category of program called "load retention." One unambiguous example of a load retention program is the situation where a program keeps a customer from relocating to another utility service area. However, computationally the equations and guidelines included in SPM to accommodate Fuel Substitution and Load Building programs can also handle this special situation as well.

4.3 Basic Methods

The SPM identifies the cost and benefit components and cost-effectiveness calculation procedures from four major perspectives: Participant, Ratepayer Impact Measure (RIM), Program Administrator Cost (PAC), and Total Resource Cost (TRC). A fifth perspective, the Societal, is treated as a variation on the Total Resource Cost test. The results of each perspective can be expressed in a variety of ways, but in all cases it is necessary to calculate the net present value of program impacts over the lifecycle of those impacts.

Table 4-1 summarizes the SPM cost-effectiveness tests. For each of the perspectives, the table shows the appropriate means of expressing test results. The primary unit of measurement is based on convention established by the staffs of the two California Commissions. Secondary indicators of cost-effectiveness represent supplemental means of expressing test results that are likely to be of particular value for certain types of proceedings, reports, or programs.

The SPM does not specify how the cost-effectiveness test results are to be displayed or the level at which cost-effectiveness is to be calculated (e.g., groups of programs, individual programs, and program elements for all or some programs). It is reasonable to expect different levels and types of results for different regulatory proceedings or for different phases of the process used to establish proposed program-funding levels. For example, for summary tables in general rate case proceedings at the California Public Utilities Commission, the most appropriate tests may be the RIM lifecycle revenue impact, Total Resource Cost, and Program Administrator Cost test results for programs or groups of programs. The analysis and review of program proposals for the same proceeding may include Participant test results and various additional indicators of cost-effectiveness from all tests for each individual program element. In the case of cost-effectiveness evaluations conducted in the context of integrated long-term resource planning activities, such detailed examination of multiple indications of costs and benefits may be impractical.

Table 4-1 Cost-Effectiveness Tests	
Participant	
Primary	Secondary
Net present value (NPV) (all participants)	Discounted payback (years) Benefit-cost ratio Net present value (average participant)
Ratepayer Impact Measure	
Lifecycle revenue impact per Unit of energy (kWh or therm) or demand customer (kW) Net present value	Annual revenue impact (by year, per kWh, kW, therm, or customer) First-year revenue impact (per kWh, kW, therm, or customer) Benefit-cost ratio
Total Resource Cost	
Net present value	Benefit-cost ratio (BCR) Levelized cost (cents or dollars per unit of energy or demand) Societal (NPV, BCR)
Program Administrator Cost	
Net present value	Benefit-cost ratio Levelized cost (cents or dollars per unit of energy or demand)

Rather than identify the precise requirements for reporting cost-effectiveness results for all types of proceedings or reports, the approach taken in the SPM is to (a) specify the components of benefits and costs for each of the major tests, (b) identify the equations to be used to express the results in acceptable ways; and (c) indicate the relative value of the different units of measurement by designating primary and secondary test results for each test.

The algebra involved in each of the test perspectives is shown in Table 4-2, which also identifies the key question that is addressed by each test.

Table 4-2
The Algebra of Cost-Effectiveness

Test	Key Question	Benefits	Costs
Total Resource Cost (TRC)	Is resource efficiency improved?	Avoided supply-side costs	Program costs (including those borne by the utility and the customer)
Participant (P)	Is the participant better off?	Bill decrease Customer incentives	Program costs (borne by the participant) Participation fees
Rate impact measure (RIM)	Are rates lowered?	Avoided supply-side costs Participation fees	Revenue loss Customer incentives Program costs (borne by the utility)
Utility cost (UC) /Program administrator cost	Are revenue requirements lowered?	Avoided supply-side costs	Program costs (borne by the utility) Customer incentives

It should be noted that for some types of DSM programs, meaningful cost-effectiveness analyses cannot be performed using the SPM tests. The following guidelines are offered to clarify the appropriate "match" of different types of programs and tests:

1. For generalized information programs (e.g., when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost-effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts.

2. For any program where more than one fuel is affected, the preferred unit of measurement for the RIM test is the lifecycle revenue impacts per customer, with gas and electric components reported separately for each fuel type and for combined fuels.

3. For load building programs, only the RIM tests are expected to be applied. The Total Resource Cost and Program Administrator Cost tests are intended to identify cost-effectiveness relative to other resource options. It is inappropriate to consider increased load as an alternative to other supply options.

4. Levelized costs may be appropriate as a supplementary indicator of cost per unit for electric conservation and load management programs relative to generation options and gas conservation programs relative to gas supply options, but the levelized cost test is not applicable to fuel substitution programs (since they combine gas and electric effects) or load building programs (which increase sales).

The delineation of the various means of expressing test results in Table 4-1 is not meant to discourage the continued development of additional variations for expressing cost-effectiveness. Of particular interest is the development of indicators of program cost effectiveness that can be used to assess the appropriateness of program scope (i.e. level of funding) for General Rate Case proceedings. Additional tests, if constructed from the net present worth in conformance with the equations designated in the SPM manual, could prove useful as a means of developing methodologies that will address issues such as the optimal timing and scope of demand-side management programs in the context of overall resource planning. Some additional test perspectives are discussed in the next section.

4.4 Balancing the Tests

The SPM tests are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the TRC Test, the Societal Test, and the UC/PAC Test, must be compared not only to each other but also to the RIM Test. This multi-perspective approach will require program administrators (including the utilities) and regulatory agencies to consider tradeoffs between the various tests. Issues related to the precise weighting of each test relative to other tests and to developing formulas for the definitive balancing of perspectives involve value judgments that have to be factored in by the regulatory bodies in each jurisdiction.

The following sidebar contains an example of a hypothetical DSM program for a hypothetical utility, Electric Light & Power (EL&P) company. By working through the economics of this program for EL&P, the sidebar illustrates the trade-offs that have to be made in practice between allocating benefits across multiple stakeholders.

SIDEBAR 2
SHOULD ELECTRIC LIGHT & POWER (EL&P) IMPLEMENT A DEMAND-SIDE OPTION?

By implementing a potential demand-side option, EL&P can decrease the growth in customer usage	100 kWh (per customer)
Average price	10 c/kWh
Marginal energy cost (supply-side)	20 c/kWh
Incremental demand-side cost (Cost of program)	5 c/kWh
Decrease in EL&P's supply-side costs	20 x 100 = 2,000 cents
Increase in EL&P's demand-side costs	5 x 100 = 500 cents
Total Resource Cost (TRC) test	2,000 – 500 = 1,500 cents
Revenue loss	10 x 100 = 1,000 cents
Rate Impact Measure (RIM) Test EL&P	1,500 – 1,000 = 500 cents

EL&P should implement the program, since it passes both the TRC and RIM tests.

To bring out the sensitivity of the results to underlying assumptions, some of the numbers in the previous example are changed in Sidebar 3. Four alternative cases are considered. Different policy conclusions follow. In some cases, the program would not be implemented while in others it would continue to be implemented.

Sidebar 3 There are other potential scenarios of demand-side programs
If Average Price is 30 c/kWh and not 10 c/kWh, and everything else is the same as on the previous slide, is the program still worth doing?
Maybe, since it still passes TRC but fails RIM
If demand-side cost is 25 c/kWh, and nothing else has changed, is the program worth doing?
No, since it fails both TRC and RIM
If the program also produces a 1 kW reduction in peak demand, and nothing else has changed, is the program worth doing?
We need to know the marginal cost of capacity during the on-peak time; the program will probably look better on both tests than before since the reduction in supply-side costs will be higher
If the program reduces peak load by 100 kWh and raises off-peak load by 50 kWh, is it worth doing?
We need to know the marginal cost of energy during the off-peak time; the program will look better on the RIM test and worse on the TRC test than before

The key point here is that the TRC and RIM tests measure benefits to different stakeholders. The TRC test measures net benefits to the national economy while the RIM test measures the impact on utility earnings. Passing both tests is highly desirable but not essential. This leads to the following decision matrix.

Table 4-3
DSM Program Decision Matrix

		TRC Test	
		Pass	**Fail**
RIM Test	**Pass**	Implement since it will lower total resource costs and customer rates	Implement if social concerns about increased use of total resources can be addressed
	Fail	Implement if special regulatory mechanisms are created to recover lost revenues by raising rates	Do not implement

4.5 Going Beyond the Standard Practice Tests

The cost-effectiveness of demand-side programs is usually based on the SPM tests described in the previous section. This section compares the SPM with alternative tests of economic welfare.

4.5.1 Bill Savings And Changes in Consumer Welfare

SPM uses bill savings to measure the impact of programs on consumer welfare. A TOU rate program, which raises the on-peak price and lower the off-peak price, will tend to reduce on-peak usage and raise off-peak usage. The portion of the bill due to the on peak period will rise and the portion due to off-peak usage will fall. The net effect may be a reduction or an increase in the consumer bill. The PT estimates the impact of the program on consumer welfare by the savings in the consumer bill.

The PT does not measure the "sacrifice" consumers make when they reduce usage during the on peak period, nor does it measure the "gain" consumers experience when they increase usage during the off-peak period. The writers of SPM, for reasons discussed below, choose to stay away from such measurements. However, there is a vast literature in welfare economics that can be consulted for guidance. During the mid-nineties, a few economists did venture down this path. They put forth several "new" test concepts for dealing with a variety of energy efficiency and technology-based load management programs based on the principles of welfare economics. In their analysis, they did not discuss the cost effectiveness analysis of rate programs. We first review their accomplishments, and then extend their framework for looking at rate programs.

Patricia Herman (1994) advanced the notion of a Value Test in 1994. She applied this test to data from two utilities, Public Service Company of Indiana (PSI) and the Tennessee Valley Authority (TVA). She showed that energy efficiency programs often passed the TRC test but failed the RIM test, because prices were often higher than marginal costs. In such cases, she showed that if the TRC test was adjusted for price elasticity effects caused by the need to raise rates, it would provide smaller benefits than the standard TRC test.

Herman also showed that "beneficial electrification" programs that sold more electricity would fail the TRC test and the PT test, but pass the RIM test. They would often pass the Value Test, once a value was placed on the benefit customers derived from the new application of electricity in the form of factors such as reduced pollution, less noise, and higher productivity. Herman recommended that utilities and commissions use the Value Test for making program Go/No Go decisions, and abandon the SPM tests. In the same year, Braithwait and Caves (1994) put forward a proposal for estimating a Net Economic Benefits test that was based on the notions of consumer surplus and producer surplus that are discussed later in this memo.

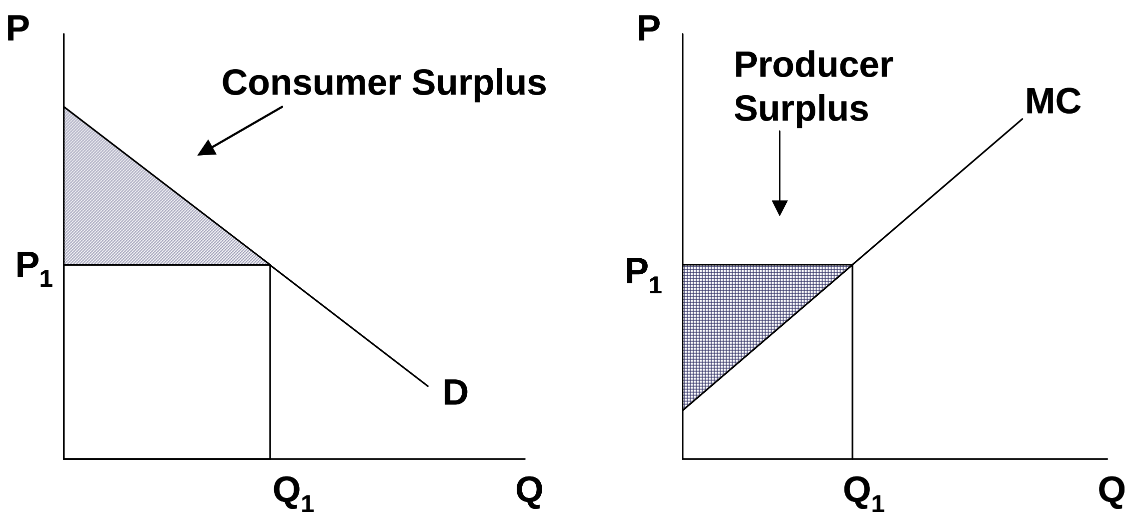
The Herman and Braithwait-Caves tests were presented at numerous industry conferences. While they served an important function in pointing out what was omitted from SPM, they did not find ready acceptance among the regulatory community. They ran into two primary barriers: first, there was a perception that tests required knowledge of the price elasticity of demand for electricity, and second, they required knowledge of the customer's willingness to pay for intangible product attributes. Sometimes, they also ran into a third barrier. The tests were viewed as an attempt to justify load building or electrification programs.

Cost-effectiveness analysis of rate programs based on SPM will contain information on the TRC, RIM and PT tests but not directly address the issue of changes in consumer or producer welfare. These questions can be addressed by replacing the SPM methodology with the concept of economic surplus (ES).

ES is defined as the sum of consumer surplus (CS) and producer surplus (PS). CS is the difference between what the consumer is willing to pay for X units of a product (or service) and what the consumer actually pays for it. The consumer's willingness to pay for a unit of consumption equals the marginal utility (or satisfaction) that he or she derives from consuming that unit. For a normal good, it declines with additional units consumed, and yields the familiar downward sloping demand curve.

Graphically, as shown in Figure 4-1, CS consists of the triangular area toward the left of the downward sloping demand curve and above the horizontal price line. CS as a concept has a long history in cost-benefit analysis. A French engineer, Jules Dupuit, who was estimating the value of public work projects, first put it forth in 1844. The English economist Alfred Marshall popularized the concept in the early part of the twentieth century, and it is now found in every economics textbook. See, e.g., Samuelson-Nordhaus (1998).

Figure 4-1
Consumer and Producer Surplus



CS responds in intuitively expected ways to price changes. If the price of a commodity goes up, CS shrinks and if the price goes down, it expands. Some authors, beginning with Sir John Hicks of Oxford University in the 1940s, have criticized CS for being a misleading measure of changes in consumer welfare. It involves movements along a demand curve where income and not consumer welfare is being held constant. These authors have argued that a better measure is obtained by holding the consumer's utility constant, and asking what income compensation needs to be paid to the consumer at the higher price to so that he or she can experience the same level of satisfaction that he or she was experiencing at the old prices. If the customer's utility level is held constant at the old prices, the resulting measure of welfare is called the Compensating Variation (CV) in consumer income; and if the utility level is held constant at the new prices, the measure is called Equivalent Variation (EV) in consumer income.

In general, for a normal good whose demand curve is downward sloping, CV and EV bound CS. Willig (1976) has shown that for small price changes, CS is a good approximation to the theoretically more accurate welfare measures, CV and EV. He showed that if the consumer's income elasticity of demand is 0.8 and if CS is 5 percent of income, then CV is within 2 percent of CS. Given the errors in estimating price elasticities of demand, it is sufficient to measure welfare changes with CS. Thus, Willig concludes: "at the level of the individual consumer, cost-benefit analysis can be performed rigorously and unapologetically by means of consumer's surplus."

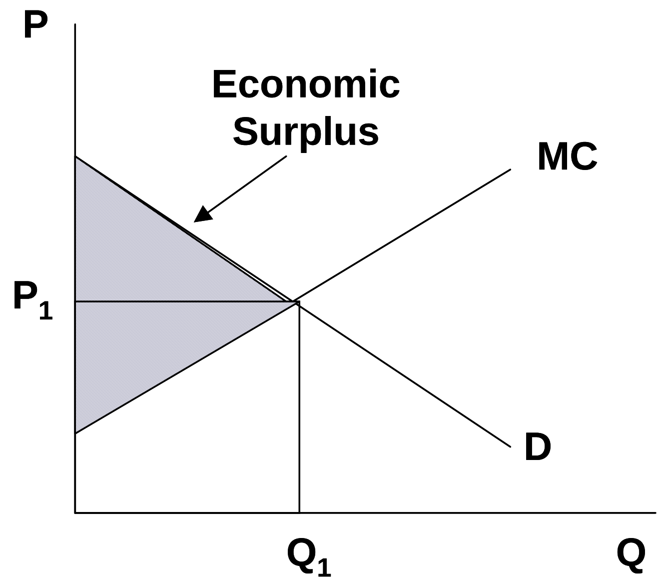
As noted earlier, there is no reference to CS in SPM, which relies instead on changes in the consumer's bill to measure changes in consumer welfare. The reason for this is that the writers of SPM were not confident that regulators and other policy makers would put much faith in estimated price elasticities, which are a critical element of estimating CS. They were concerned that controversies about the price elasticities would enter the discussion, and prevent any consensus from developing about the program's cost effectiveness. Thus, they choose to focus only on bill changes. It is important to keep in mind that the bulk of the applications of SPM were expected to involve technology programs, and not rate programs. The price of electricity was held constant in such calculations, since the developers of SPM were mostly concerned about energy efficiency programs and technology-based load management programs. Changes in the quantity of electricity consumed were determined exogenously, and were often based on engineering rules of thumb. It was common to reduce electric usage in proportion to the efficiency change represented by a movement from the old technology to the new technology.

When SPM is applied to rate programs, such as a time-of-use (TOU) rate, it is no longer possible to stay away from price elasticities. These are necessary for predicting the new quantities that would result from the new prices. Since the old and new prices are known, along with old quantities, price elasticities can be used to predict new quantities. Thus, old and new bills can be estimated, and bill changes derived by subtracting the new bill from the old. This is what we have done in our analysis thus far.

However, we have the information that is needed to calculate CS. TOU rates raise prices during the peak period and lower them during the off-peak period. Higher prices during the peak period result in lowered consumption, and "consumer sacrifice"; lower prices during the off-peak period raise consumption, and "consumer gain." It is an empirical question whether the gain is greater than the sacrifice.

Producers Surplus (PS) is the difference between the total revenue from producing X unites and the total cost incurred in producing those units. Graphically, it constitutes the triangular area below the price line and to the left of the marginal cost curve. Economic Surplus is the sum of CS and PS. In a competitive market, price equals marginal costs, and at that point ES is maximized, as shown in Figure 4-2. The value that customers place on the utility derived from consuming the last unit is exactly equal to the marginal cost of producing that unit. Economic efficiency is maximized. Any other price would reduce welfare, and this constitutes one of the theorems of welfare economics.

Figure 4-2
Maximizing Economic Surplus



In the real world, and especially in the world of electricity, prices are rarely based on marginal costs. Under cost-of-service regulation of electric monopolies, prices are often set equal to average costs. Thus, they exceed marginal costs during the off-peak period and are below marginal costs during the on peak period. There is a potential for improving economic efficiency by raising prices during the on peak period and lowering them during the off-peak period, so that they better approximate the marginal costs of electricity. The new prices need to reflect both marginal energy and marginal capacity costs.

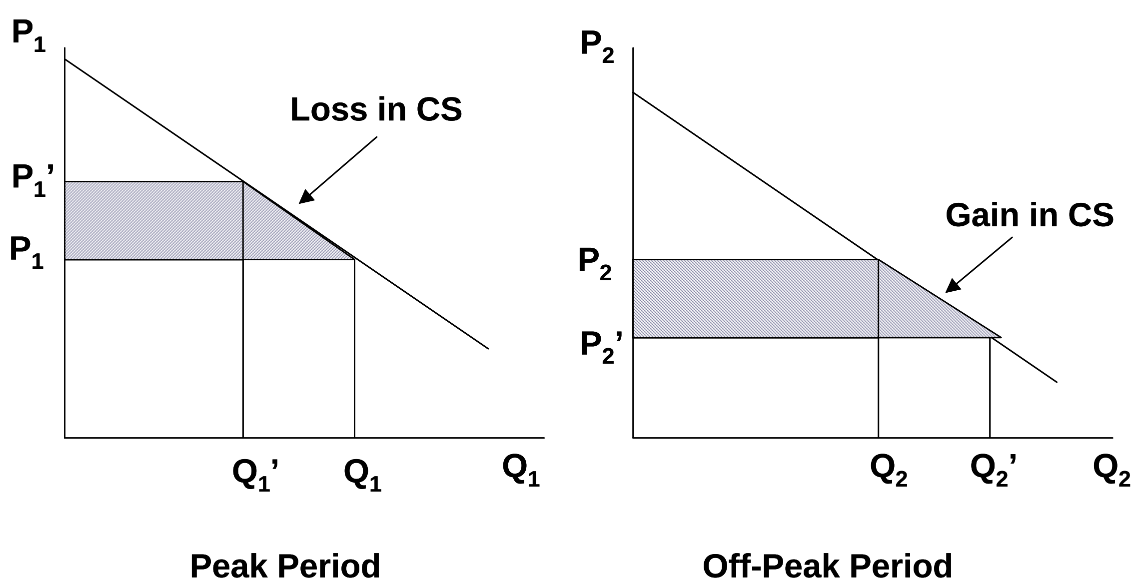
A shift to TOU pricing would improve economic efficiency in the aggregate, i.e., for all customers, if it raises ES. However, even if ES rises in the aggregate, some customers may be made worse off. This should not prevent that policy from being implemented, according to a commonly used criterion in welfare economics that has been put forth by Kaldor-Hicks. These authors argue that if the gainers from a public policy can compensate the losers, that policy is worth doing. The Kaldor-Hicks criterion allows a wider variety of policies to be considered than the more restrictive Pareto criterion, which would only allow such policies to be undertaken that made no one worse off, while making at least one person better off.

TOU rates can be evaluated using the ES test, rather than the SPM tests. A study by two of my CRA colleagues, Jan Paul Acton and Bridger Mitchell (1979), provides one of the earliest applications of applied welfare economics to TOU pricing design. Working with data from the Los Angeles TOU pricing experiment, they estimated welfare impacts through estimation of CS and PS for 16 customer segments ranging from less than 200 kWh per month to those consuming more than 2,500 kWh per month. The baseline price was 5 cents per kWh, and the new TOU price featured 9 cents per kWh during the peak period and 3 cents per kWh during the off-peak period. The TOU rate was designed to be revenue neutral and it was assumed that the new prices reflected LADWP's marginal costs.

The estimated per-customer ES values ranged from \$.08 per month to \$5.78 per month, and can be compared with bill changes that ranged from an increase of \$.15 per month to a decrease of \$10.90 per month. Metering and billing costs were estimated to cost \$1.42 per customer per month. Acton-Mitchell concluded that TOU pricing would only be cost-effective for customers whose monthly consumption exceeded 1,100 kWh. Only four percent of customers fell into this category, but they accounted for over 17 percent of usage. However, for households with swimming pools, the program was cost-effective when monthly usage exceeded 800 kWh.

Preliminary estimates of the impact on CS of PSE's TOU program suggest that changes in CS are positive, indicating that welfare is improved by shifting to TOU rates. Consumers gain more by increasing off-peak usage than they lose by reducing on peak usage. This is shown in Figure 4-3.

Figure 4-3
Impact of TOU Pricing on Consumer Surplus



However, the estimated value of CS is about *half* the value of bill savings. Tests were carried out with a variety of different values of the price elasticity of demand, price ratios, and shares of on peak and off-peak usage to see if this relationship of one-half is specific to PSE's filed tariff, or if it is likely to be valid across a variety of TOU rate designs. The relationship was found to be valid across a wide range of revenue-neutral TOU rate designs.

4.5.2 Dealing with Intangible Benefits and Costs

The consumer's willingness to pay for electricity is fully captured by the demand curve for electricity, because the curve shows the maximum amount the consumer will pay for various quantities of electricity. This maximum amount captures both the tangible and intangible attributes of electricity. Using estimates of the price elasticity of demand for electricity, we can infer the consumer's underlying demand curve of electricity. There is no further need to estimate any intangible benefits or costs associated with electric usage. That would amount to double counting.

In our view, there is no place for estimating intangible benefits and costs in cost effectiveness analysis of demand side programs, once the demand curve for electricity has been estimated. Of course, if the demand curve has not been estimated, then there would be a need for estimating both tangible and intangible benefits and costs.

Estimating the value of intangible benefits and costs is more nebulous than estimating changes in economic surplus. Some analysts have tried to estimate the value of intangible benefits and costs by the clever use of inequalities based on the theory of revealed preference due to Paul Samuelson. Suppose that a consumer has been observed buying a new technology that increases electric usage. This customer decision will surely fail the TRC test, since that test measures the avoided electric energy and capacity costs created by the new technology. A load building technology will incur additional energy and capacity costs, rather than avoid them. It would also fail the PT test, since the new technology would raise customer bills. However, the TRC and PT tests fail to value the intangible benefits that customers may derive from the new technology, such as better comfort, enhanced esthetics, and higher productivity. If a customer buys such a technology, at an incremental life cycle cost of $1,000, the analyst can then infer that the value provided by the technology must be at least $1,000 and could be substantially higher. However, since the customer has already chosen to implement the technology without any utility assistance, there is no need to provide the customer with a programmatic incentive.

Alternatively, consider the case of a consumer who has not chosen to implement the technology. This problem is analytically much more complicated than the previous one. A program incentive may be needed to overcome market barriers and imperfections in the energy market that are keeping the customer from implanting the technology, in spite of its intangible benefits; i.e., the value of the barriers may exceed the value of the intangible benefits. However, the quantitative value of the barriers would remain obscured, and it would be unclear how much to spend on the program. Herman (1994) assumes that the program eliminates a certain percentage of the barriers, but does not provide a basis for her estimates.

In such cases, it may be appropriate to conduct market research among customers to estimate their willingness to pay for such intangible attributes such as comfort, noise abatement and productivity enhancement. Insights can be obtained from the vast literature in marketing devoted to designing and marketing new products. Statistically representative samples of customers can be presented hypothetical product bundles and asked to rank them. The bundles feature alternative configuration of product features. A form of multivariate statistical analysis known as conjoint analysis can then be used to estimate customer willingness to pay for the various product features that differ across the bundles. This technique, along with several others, is discussed in Urban-Hauser (1993), which also includes a number of case studies drawn from a variety of industries.

Such techniques are beginning to gain acceptance in the electricity industry. A recent example is provided by a multi-year project conducted by EPRI that involved seven utilities as participants. Called ShareWars, the project was designed to determine customer interest in switching suppliers. It involved a national telephone survey of about 5,000 customers. See Wood-Gambin-Garber (2000) for a discussion of the project methodology and results.

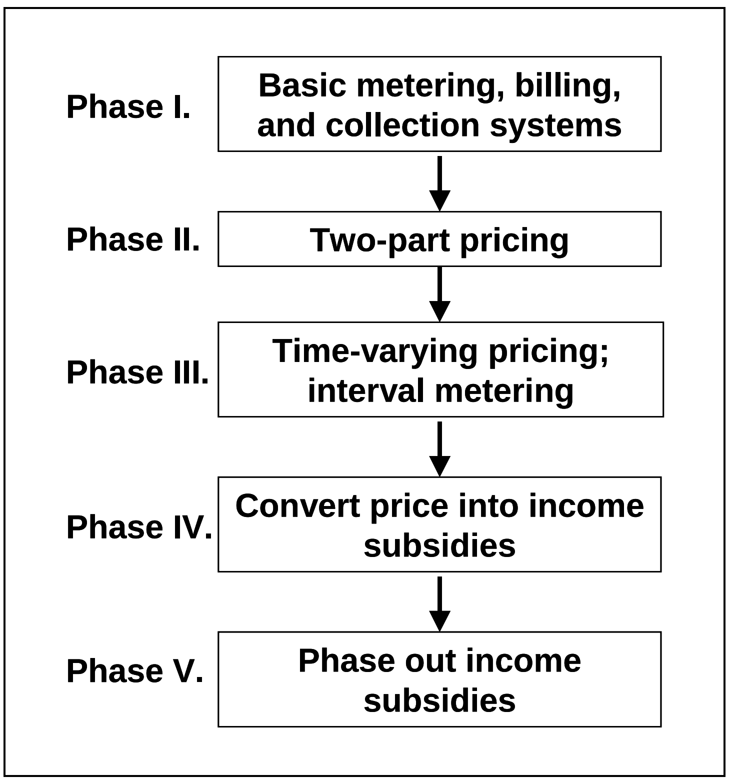
Empirical estimates of willingness to pay, derived from conjoint analyses, are used to calibrate models of customer preference and behavior that fall in the "logit" family of models. Such "qualitative choice" models, extensively discussed in Urban-Hauser (1993), can be used to predict how many customers will buy what type of device or choose what type of rate structure. If the number of participating customers is insufficient from a public policy standpoint, then policies can be developed for recruiting additional participants. The cost-effectiveness of such policies can be assessed using the SPM tests or the ES test discussed in the previous section.

Chapter 5 - Moving Forward with Pricing Reform

A review of lessons learned in Section 2.3 found that costly cash rebates are not a cost-effective and sustainable way for implementing DSM programs. A much better way is to change energy prices so they reflect the true scarcity value of electricity by time of day. However, price signals can only be sent once the practice of electricity pricing has been reformed. This will involve changing the structure of rates, i.e., the rate design, as well as the level of rates.

To successfully implement pricing reform, it is advisable to follow a phased approach in order to avoid creating confusion or alarm in the energy market place and in order to manage the expectations of the various players in the market. Depending on each country's situation, this process may involve as many as five phases. These phases are depicted in Figure 5-1.

Figure 5-1
Phases in Pricing Reform



In Phase I, it is essential to lay the foundation for pricing reform. This means ensuring that all electricity consumption is metered, billed and collected. This is a necessary condition for the efficient functioning of any market and applies to electricity as much as it does to any other commodity. Without this condition, property rights for the electric utility (i.e., its right to be paid for its product, electricity) cannot be established and it cannot be expected to function as a viable commercial enterprise. At this phase, some key decisions will need to be made. For customers who had no meters before, new interval meters could be installed instead of standard meters. The incremental cost of installing the interval meters is very small. Such customers could then be given a choice of time-varying rates or they could be included in a pilot program to test the effectiveness of such rates. Another decision may involve the installation of direct load controls on key energy-using devices, in return for giving a credit to the customer on their monthly bill. The load controllers would allow the utility to remotely turn off the key energy-using devices during critical times. This option can even be implemented on customers who do not have any type of meter on their premises.

In Phase II, a two-part pricing scheme can be implemented. In the first part of the rate, the customer would pay the existing rate for a pre-specified level of consumption called the customer base load (CBL). There are several ways to compute the CBL, with the easiest being to set it equal to the average of the customer's past 12 months of usage. In the second part of the rate, the customer would be billed at the marginal cost of electricity. This would apply to increases or decreases in usage from the CBL. Thus, at the margin, the customer would see the true price of electricity. In other words, consumers would agree to purchase a specific amount of energy at fixed, regulated prices. Any additional consumption would be priced at variable, pre-determined "market" price set each month, and any reduction in consumption would be credited at the variable "market" price. One of the proponents of this approach terms the strategy as a Fixed/Variable program.[28]

The advantage of this approach is its simplicity and the fact that it does not involve a change in the customer's meter. The weakness of this approach is that while the price of electricity varies by time of day, this approach is forced to use a single number. The customer has the same incentive to reduce usage at the time of the system peak and at all other times. Another program that can be introduced at this stage is a program along the lines of California's 20/20 program. That program gave the customers' a credit of 20 percent on their monthly bill if they reduced their monthly usage by 20 percent.

In Phase III, price signals reflecting the cost of energy come into play. Interval meters would be installed on customer premises allowing either the introduction of time-sensitive load curtailment programs or dynamic pricing programs that are revenue neutral with respect to existing rates. Load curtailment programs would target the very largest customers can be established to introduce price responsiveness in the marketplace. Dynamic pricing programs could target all customer classes. A decision would have to be made on whether to offer the rates as default tariffs to all customers or to offer them on an opt-in basis. Case studies of such programs were discussed in Section 3.

It is useful to note that two large provinces in Canada and Australia have concluded that interval metering for residential and small business customers are essential to the efficient functioning of the power market. The province of Ontario, Canada has decided to deploy about 800,000 smart meters in homes by 2007 and to have universal deployment in five years time.

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[28] Hethie Parmesano, "Making every consumer a market participant," *The Electricity Journal*, Volume 16, Issue 4, 2003.

In an address to the Ontario Legislative Assembly this past spring, Premier McGuinty signaled his government's intent to price electricity more rationally by installing "a smart electricity meter in 800,000 Ontario homes by 2007…and in each and every Ontario home by 2010." These smart meters, "combined with more flexible pricing," would provide an economic incentive for consumers to reduce energy consumption during the peak hours of the summer season when the cost of generating electricity is much higher than at other times of the year.[29]

In a similar vein, the province of Victoria, Australia has determined that "interval meters enable retailers and customers to measure real time electricity consumption and to send and respond to the cost-related price signals that are essential for the market responses needed to underpin more sustainable and efficient energy supply and consumption practices and patterns."[30] The Essential Service Commission of Victoria has stated that all large customers consuming greater than 160 MWh will have interval meters by 2008 and for all customers, including residential customers, by 2013.

In Phase IV, the problem of rate levels being subsidized would be tackled. Specifically, the magnitude of the existing price subsidy would be quantified and then converted from a price subsidy to an income subsidy. Once this happens, prices would rise to their full marginal costs but the economic impact on the customer is cushioned through an income subsidy that would allow them to consume the previous amount of electricity without experiencing any adverse impact. However, most consumers would choose to reduce their consumption of electricity, when they see the full price, and spend some of the income subsidy on other goods and services. This would make them better off than before.

In Phase V, the income subsidy would be phased out over time, consistent with the social and political goals of the jurisdiction. This would allow for customer expectations to be managed.

The issues involved in implementing Phases IV and V are amplified in the next section.

5.1 Rationalizing the Rate Level

For political reasons, governments in developing countries have subsidized the consumption of electricity. It is not possible to eliminate the subsidies overnight, but it can be done gradually. Economists have long argued that prices should be based on marginal costs, and not on average costs. Accountants would insist that, at a minimum, they should be based on average costs, or the utility would become insolvent on a stand-alone basis or require subsidies from the government.

It is a truism that a policy that subsidizes electricity consumption is very costly, since it keeps consumers happy in the short term while making the economy (and thus the consumers and tax payers) worse off in the long run. There is over-consumption of electricity and taxpayers have to cover the utility's losses. This process acts like an income re-distribution program. The problem

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[29] For the complete text of the April 19, 2004 speech to the Ontario Legislative Assembly, go to http://www.premier.gov.on.ca/english/news/Energy041904_speech.asp.
[30] Essential Services Commission, "Mandatory Rollout of Interval Meters for Electricity Customers: Final Decision," Melbourne, July 2004.

of income redistribution is not pronounced in mature economies such as the United States, where just about everyone pays taxes and everyone consumes electricity. However, the effects can be quite pronounced in countries such as Pakistan where only one percent of the population pays income taxes and but 50 percent consumes electricity. In India, 46 percent of the households have access to electricity, but the figure drops to 33 percent in rural areas.[31]

Governments need to change the rate level gradually, so they do not trigger a political backlash. It is unwise to remove the subsidy in one year, since people have gotten used to it over a period of several years. No one can readjust his or her lifestyle, or the operating schedule of his or her business, that quickly.

Consider the example of a fictitious middle-income country with a population of 100 million. Half the population has no access to electricity. The country has 20 million residential consumers of electricity who account for 40 percent of total consumption, with the balance occurring in the commercial, industrial and agricultural sectors. The average residential consumer has a monthly income of $1,000. It costs the state-owned electric utility 10 cents per kilowatt-hour (kWh) to generate, transmit and distribute electricity, but its government has set the tariff at 5 cents per kWh. The average customer buys 1,000 kWh per month and pays a monthly bill of $50, even though it costs the utility $100 a month to deliver this electricity. Thus, the utility loses $50 per consumer per month. To keep the utility afloat, the government (and ultimately the taxpayer) has to pay a subsidy of $12 billion per year to the utility so that it can deliver 240,000 million kWh per year to the nation's residential consumers.

As part of its restructuring process, the government accepts the notion that consumers should be given the right price signal. This message is often conveyed by international lending agencies. The government does not want to have a political revolt on its hands, by suddenly raising the price of electricity. Therefore, it adopts a pricing policy with two tracks. In track one, it raises the price of electricity to 10 cents per kWh. In track two, which is implemented simultaneously, the government announces an income subsidy of $50 per consumer, to be phased out over a three-year period. The consumer can afford to not change his usage level of 1,000 kWh. He was previously spending $50 a month on electricity, and will now be spending $100 a month, but the difference of $50 will come from the income subsidy. However, he would have a strong economic incentive to change the usage level.

Most customers will reduce usage in response to a doubling of price. Ever since the Arab oil embargo of 1973, economists have been researching how the demand for energy responds to price changes. Contrary to popular impressions, they have found that the demand for all energy forms, including electricity, does respond to price. Studies across a wide range of countries suggest that if the price of electricity were to be doubled, demand would fall by about 30 percent. In this example, demand would fall by 30 percent (300 kWh), because price has doubled. Of course, the income subsidy would cause consumption to move in the opposite direction, yielding a net reduction of say 250 kWh in consumption. At the new consumption of 750 kWh a month, the customer's electricity bill would be $75 per month, and he would have $25 a month left over to spend on other goods and services.

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[31] See Sharma (2002).

The utility would not lose any money even though its revenues go down, since it would be paid its full cost on every kWh sold. Annual electricity consumption by residential consumers would fall to 180,000 million kWh. About a quarter of the fossil fuels being used to generate electricity would be available for other industries, and the utility would have to build fewer power plants, freeing up scarce capital resources. Environmental quality will be enhanced. Over time, the income subsidy would be phased out, helping to reduce the drain on the budget.

As discussed in the following sidebar, the Pakistani government chose to reform the rate level before reform the rate designs, and it was not alone in acting in this fashion. Most governments go down this path, essentially placing the cart before the horse. Painfully, they discover that such a course of action is unwise. First of all, while overall electricity consumption may be optimized with the increase in price, the time-pattern of consumption will stay unchanged. Consumers will have no incentive to shift their pattern of usage away from expensive on-peak hours to inexpensive off-peak hours. Secondly, if the rate increase has to be scaled back due to political considerations, it will fail to offset the need for government subsidies.

In matters of state policy, it is prudent to "make haste slowly." Problems that have accumulated over several decades cannot be resolved with one rate increase. A steep rate increase would actually raise the incidence of power theft, further compounding the shortage of revenue. Unlike Pakistan that has a large army, not every country can afford to send two army soldiers with each meter reader to ensure that they are read correctly. Theft is a big problem in India, where 20 percent of the power losses may actually be due to theft of power. The corresponding statistic for the United States is three percent. Karachi Electric Supply Corporation (KESC), where a pair of army soldiers does not escort every meter reader, is faced with a staggering theft rate of 40 percent. Another reason why revenues are insufficient to cover costs is that several customers in remote locations, such as Pakistan's federally administered tribal areas adjacent to Afghanistan, are not metered. In other countries, politically influential customers such as farmers are not metered either.

SIDEBAR 4
ELECTRICITY PRICING IN INDIA AND PAKISTAN

In India, the amount of the subsidy went up by a factor of four between the years 1992/93 and 2000/01. Tariffs cover only 70 percent of cost, and the rate of return for electric utilities is a negative 17 percent.[32]

The situation in Pakistan is of a similar nature. Currently, Pakistani consumers are served by two government-owned utilities, the Water and Power Development Authority (WAPDA), which serves the entire country except for the city of Karachi, and the Karachi Electric Supply Corporation (KESC).[33] In 1998, the combined losses of these two companies amounted to about half a billion dollars. Several factors account for these losses, including chronic inefficiencies in generation, transmission and distribution; corruption and theft; a drop in the share of hydropower caused by drought; above market take-or-pay contracts with IPPs that were signed in the mid-nineties; and tariffs that were set below costs.[34]

Tariffs cover only 70 percent of WAPDA's average costs, necessitating a sizeable subsidy equal to almost one percent of GDP. They cover an even smaller share of marginal costs, which are the economically correct measure of resource scarcity. Pakistan provides an example of the problems that can be created by drastic changes in rate levels.

In March 2001, WAPDA requested a modest price hike, following through on commitments that the finance ministry had made to the International Monetary Fund.[35] This rate hike would have covered about 80 percent of its revenue shortfall. In July, the National Electric Power Regulatory Authority (NEPRA) gave WAPDA less than half of what it wanted.[36]

Not surprisingly, a hike of this magnitude stirred considerable unrest. It exposed ten million domestic consumers to a sixteen percent hike in their power bills. It also exposed the politically powerful and vocal feudal lords to a hike of seventeen percent in their power bills, which are mostly used for powering tube wells. Industry, which has the option of self-generating power and has long been subsidizing the other sectors, was given a rate hike of nine percent.

Every government ministry rose in arms against the price hike, as did the country's Planning Commission.[37] Realizing that the last thing he needs is a revolution fomented by a price hike, the country's military president stepped into the fray. General Musharraf asked NEPRA to reconsider the case, essentially vetoing the rate hike. The NEPRA Chairman resigned.

[32] See Prabhu (2002).
[33] The Government of Pakistan has established distribution utilities in all major urban areas and is in the process of dividing up WAPDA.
[34] WAPDA claimed that it would save $1.5 billion over the 30-year life of the IPP contracts. So far, it has continued to lose money on these contracts, which have set a fixed price of 6.5 cents per kWh, and have obligated WAPDA to pay 60 percent of the contracted amount regardless of the size of power purchased. In the current fiscal year, WAPDA has to pay Rs 108 billion to the IPPs.
[35] See www.imf.org for details.

[36] See Khalid Mustafa, "Power tariffs raised," *Daily Times*, July 19, 2002.
[37] See Khaleeq Kiani, "Power tariff hike opposed," *Dawn*, July 17, 2002.

Chapter 6 - Glossary of DSM Terms

Automated control	Any technology that allows the customer or electric service provider to pre-program a control strategy - for an individual electric load, group of electric loads, or an entire facility - to be automatically activated in response to a dispatch.
Critical-peak pricing (CPP)	A dynamic rate that allows a short-term price increase to a predetermined level (or levels) to reflect real-time system conditions. In a *fixed-period* CPP, the time and duration of the price increase are predetermined, but the days are not predetermined. In a *variable-period* CPP, the time, duration and day of the price increase are not predetermined.
Demand response (DR)	The ability of an individual electric customer to reduce kWh usage or kW demand in a given time period, or shift that usage to another time period, in response to a price signal or a financial incentive.
Dispatch	A broadcast signaling the initiation of a control strategy or price adjustment.
Dynamic rate	A rate in which prices can be adjusted on short notice (typically an hour or day ahead) as a function of system conditions. A dynamic rate cannot be fully predetermined at the time the tariff goes into effect; either the price or the timing is unknown until real-time system conditions warrant a price adjustment. *Examples: real-time pricing (RTP), critical peak pricing (CPP)*
Flat rate	A rate in which the same unit price (expressed in currency units per kWh) is charged for all hours during a predetermined time period, usually a season or year. It is an example of linear pricing. This is to be contrasted with non-linear pricing, whose examples include an inclining or declining block rate, in which the price per unit varies with the numbers of units consumed.
Information	Facts and data that facilitate consumer response to energy prices. "Basic information" would consist of printed information that contains the tariff and discusses its potential impact on expected monthly energy costs. "Technical information" describes technologies that can be used to respond to the tariff. "Energy information" describes the consumer's energy consumption patterns on an ongoing basis, to help the consumer adjust behavior and infrastructure to reduce monthly energy costs.

Interval meter	An electricity meter or metering system that records a customer's load profile by storing in memory each consecutive demand interval, which typically consists of a period ranging from 5 minutes to an hour, synchronized to the hour. The meter can be read through a hand-held device (typically monthly) or through a data link to a central metering master station (typically daily).
Notification	Information provided to customers regarding price adjustments or system conditions. "Day-ahead" notification provides at least 24 hours advance notice. "Hour-ahead" notification provides at least one-hour advance notice.
Price elasticity	A measure of the sensitivity of customer demand to price. It is expressed as the ratio of the percent change in demand to the percent change in price; e.g. a 10 percent load drop in response to a 100 percent price increase yields a -0.10 elasticity. Several elasticity concepts can be defined for electricity usage by time period. For example, the own-price elasticity of peak period demand relates changes in peak period demand to changes in peak period price. The cross-price elasticity of demand relates changes in usage in one period to changes in price in another period.
Rate	The unit price (expressed in currency units per kWh of energy consumption or per kW of billing demand) of electricity. It may vary with the amount of usage or demand, or with the time period of use.
Real-time pricing (RTP)	A dynamic rate that allows prices to be adjusted frequently, typically on an hourly basis, to reflect real-time system conditions.
Revenue neutrality	A regulatory requirement that alternative rate designs recover the same total revenue requirement from customers if they make no change in their usage patterns.
Seasonal rate	A rate in which the rate varies by season.
Smart thermostats	A heating, ventilation and air-conditioning (HVAC) thermostat that: (1) automatically responds to different electricity prices by adjusting the temperature set point or the operation of the HVAC equipment, using pre-programmed thresholds that have been specified by the customer; (2) displays energy information and rates, and notifies the customer of rate changes; and/or (3) can be programmed to control devices other than the HVAC system.

System conditions	Any or all of the following: wholesale electricity costs, reliability conditions, environmental impacts, and/or the relationship between supply and demand.
Tariff	A public document setting forth the services offered by an electric utility, rates and charges with respect to the services, and governing rules, regulations and practices relating to those services.
Time-of-day (TOD) rate	A rate where the price of electricity varies by time period within a day. It typically includes two or three time periods per day.
Time-of-use (TOU) rate	A rate where the price of electricity either varies diurnally (by time period within a day) or seasonally. It includes TOD and seasonal rates as special cases.
Tiered rate	A rate in which predetermined prices change as a function of cumulative customer electricity usage within a predetermined time frame (usually monthly). Prices in an 'inverted tier' rate increase as cumulative electricity usage increases. Prices in a 'declining tier' or 'declining block' rate decrease as cumulative electricity usage increases.

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