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**APPLICATIONS OF DYNAMIC PRICING IN DEVELOPING AND  
EMERGING ECONOMIES**

**PREPARED FOR**

The World Bank

1818 H Street N.W.

Washington, DC 20433

**PREPARED BY**

Charles River Associates

5335 College Avenue, Suite 26

Oakland, CA 94618

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Ahmad Faruqi  
Oakland, California

## Chapter 1- Report Objectives

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This report builds on the ideas, concepts and methodologies associated with dynamic pricing that were introduced in the DSM Primer.<sup>1</sup> Dynamic pricing involves the pricing of electricity in a way that reflects the time-variation in electricity supply costs. Examples include time-of-use pricing, critical-peak pricing and real-time pricing.

As discussed in the DSM Primer, dynamic pricing provides a mechanism for linking retail and wholesale markets in economies where the electricity market is being restructured. It can prevent market meltdowns, such as the one that occurred in the California energy market in 2000/01.<sup>2</sup> It can also be used in markets where restructuring has not yet begun and a government department, a government-owned corporation or a privately owned corporation is the sole provider of generation, transmission and distribution services.

The applicability of pricing reforms may be expected to vary across different countries, depending on the level of their economic and market development and depending on the stage of their power sector reform. There are distinct differences between the regional scenarios, arising from inter-country differences in the level of economic development and stage of power sector reform. The more advanced economies have high levels of electrification while others have very low levels of electrification. Some have unbundled and privatized their utilities, so that distribution utilities operate as independent utilities while others have kept their utilities intact as vertically integrated entities that operate either as a government department or a government-owned company. Some countries have developed technically sound methods of dispatching power plants and running power pools. A few have successfully introduced competition in wholesale markets and operate day-ahead and hour-ahead spot markets. And one or two are planning to introduce retail competition and choice of provider.

However, as argued in Chapter 2, the similarities across the four regional scenarios are greater than the differences. In most cases, the factors feed on each other in a vicious circle. In the poorer countries, low per capita incomes lead to low willingness to pay for electricity. In such countries, a culture of entitlements is often to be found that regards electricity as a free public good. This culture, nurtured by a long history of tariff subsidies, absence of meters and institutionalized theft of power, often triumphs over the establishment of property rights for the electric utility.

There is a social and political expectation that electricity should be provided below cost to all citizens. Because tariffs are low, there is no incentive for using energy efficiently. Utilities teeter on the brink of insolvency and are unable to invest in new capacity. Quality of service remains poor and blackouts are a frequent occurrence during the peak

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<sup>1</sup> Charles River Associates, *Primer on Demand Side Management: With an emphasis on price responsiveness programs*, prepared for the World Bank, February 2005.

<sup>2</sup> James L. Sweeney, *The California Electricity Crisis*, Hoover Institution Press, 2002.

season. All of these factors create power shortages and represent a critical infrastructure bottleneck that impedes economic development.

One way for dealing with power shortages is to implement DSM programs. These can be quite expensive and unsustainable over the long haul. A better approach is to implement tariff reform. For this to be successful, it has to mesh in with the restructuring of power markets that is underway in most countries. It has been implemented in varying degrees in developing and emerging economies in order to achieve efficiencies in the production and delivery of electricity.

Chapter 3 discusses how market restructuring affects the pace of pricing reform in general and dynamic pricing in particular. It finds that there is no single answer to this question. It all depends on the manner in which market restructuring is implemented. The chapter lays out a stylized restructuring process that embodies features shared by many countries.

Regardless of the manner in which a country implements industry restructuring, tariff reform is a *sine qua non* of creating a competitive power sector. As it considers different models for reforming its tariffs, the electric utility will find it useful to assess the economics of dynamic pricing. The electric utility could be a government department, a vertically integrated corporation or an unbundled distribution company. In all cases, from a national perspective, dynamic pricing will create benefits in the form of avoided generation, transmission and distribution costs. However, the benefits in their entirety would only accrue to the electric utility if it is a vertically integrated entity. If it is just a distribution company, it may only be able to count the benefits of avoiding distribution system upgrades. However, the transmission company would be able to count the benefits of avoiding transmission system upgrades and the generation company (or companies) the benefits of avoiding peaking generation capacity.

Thus, some allowance would have to be made for the specific regulatory situation and stage of market restructuring facing an electric utility provider. For example, the benefit categories that are available for evaluating demand response in a regulated market may differ from those that might be available under a deregulated market.

Chapter 4 discusses ways of reforming tariffs and introducing dynamic pricing. This involves a five-phase process, beginning with the installation of meters and billing systems, moving to two-part tariffs that do not require dynamic pricing, then to one of various forms of time-varying pricing (such as time-of-use tariffs, critical peak pricing or real time pricing), and finally to the last two steps that involve converting price subsidies into income subsidies and ultimately to phasing out income subsidies.

By now, time-varying tariffs have become widespread in developed countries. Often times, they are mandatory for large commercial and industrial customers and optional for residential customers. The peak to off-peak ratios is typically steeper for larger customers. For example, in Victoria, Australia, tariffs for low voltage customers have a peak to off-peak ratio in between 2:1 and 3:1. Corresponding tariffs for high voltage customers have a ratio in between 3:1 and 5:1.<sup>3</sup>

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<sup>3</sup> Victoria Government Gazette, October 29, 2044, Numbers S 222 and S 223.

Several developing countries have begun to implement time-varying pricing to improve their economics. For example, India's Electricity Act of 2003 provides a strong legal framework for pursuing DSM activities inclusive of TOU rates. Several energy regulatory commissions have also adopted time-of-day tariffs. The Maharashtra electricity regulatory commission has significantly enhanced the differential in peak and off peak energy charges.

Chapter 5 includes six case studies dealing with China, Thailand, Turkey, Tunisia, Uruguay and Vietnam. Most case studies discuss the implementation of standard TOU rates. One, that dealing with China, discusses CPP rates. Information is provided on the rates themselves, in the form of prices and number of periods, applicable customer segments, and in a few cases, on the impact of these rates.

Chapter 6 provides answers to frequently asked questions about dynamic pricing. For example, how does a one-recruit customer get into a dynamic pricing program? It has been observed that customers do not participate in such programs for two primary reasons. First, they are not aware that such programs exist. This barrier can be overcome by active marketing on the part of the utility. Second, they are afraid that such rates will raise their bills. Most customers don't know their load shape and don't know what the new rates would do to their bills. There are three ways in which such fears can be overcome. They can be offered a bill protection product for the first year, which would guarantee that their bill would be no higher than what they would have paid at the standard tariffs. Or they could be placed on a two-part tariff, where the first part is based on their baseline usage during a historical period and the second part is based on time-varying charges. If they preserve their baseline usage, their bill would not change. This method requires the monitoring of customer usage and development of profiles during a test period. Finally, the rates can be designed so that instead of being "revenue neutral" for the typical or average customer, they are revenue neutral for an above average peak user.

Chapter 7 contains a glossary of terms that were used in this report and Chapter 8 lists all references that were cited in it.

## Chapter 2 - Four Regional Scenarios

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The applicability of pricing reforms discussed in the next set of chapters may be expected to vary across different countries, depending on the level of their economic and market development and depending on the stage of their power sector reform. For illustrative purposes, it is useful to envision regional scenarios that vary in terms of the following parameters:

- Level of electrification
- Level of subsidy in electric tariffs
- Existing energy efficiency level
- State of metering and billing systems
- Quality of service and power reliability
- Ability to economically dispatch power plants
- Existence of wholesale power markets
- Integration of retail and wholesale markets
- Vertical integration or unbundling of functions
- Private or public ownership of assets

Four scenarios that encompass most global variations of these factors are described in the next section.

### 2.1 Scenario Definitions

#### 2.1.1 Regional Scenario 1

Countries in this scenario have very low electrification levels. These countries generally subsidize their electric rates for social reasons and thus there is much room for improving energy efficiency levels. The quality of metering and billing systems is poor. Fraud and technical losses create revenue insufficiencies. Utilities face difficulties in collecting payments and deterring fraud and are on the verge of insolvency.

In those countries, the quality of service is poor, leading to frequent blackouts due to either energy and/or capacity constraints. Because of low per capita incomes, customers have a limited willingness to pay for electricity and this places a limit on the rate of system expansion that can be financed from customer charges. Some customers may have installed affordable back-up generators, to ensure reliability of power supply, but these are rarely integrated with the utility grid. The rules for optimization and dispatch of the power system are still in an embryonic stage. Examples include the countries of Sub-Saharan Africa, such as Tanzania.

#### 2.1.2 Regional Scenario 2

Countries in this scenario have high electrification levels in urban and semi-urban areas but low electrification level in rural areas. Those countries may have the technical and commercial capabilities to operate and dispatch the power system. Power pools, spot prices and a system for managing congestion may exist, along with some competition in

the wholesale market. Despite those advancements, distribution utilities (generally privatized) encounter difficulties in collecting payments and in preventing fraud. Generally, no energy efficiency targets have been established as part of the privatization process, and as a consequence distribution companies have no explicit economic or regulatory incentives to implement large-scale energy efficiency or demand response (DR) programs. Retail tariffs for low consumption groups are generally subsidized. Usually there is limited interaction between the wholesale and retail markets, “isolating” the customer from market reality and therefore making demand response programs less effective. Examples include Argentina and Brazil.

### 2.1.3 Regional Scenario 3

This scenario includes countries with reasonable electrification levels, particularly in urban areas, but they have a large number of customers who are on subsidized tariffs. Low tariffs, in conjunction with lack of metering for some types of customers, leads to increased growth and waste of energy in these countries. For example, in India, electricity is provided free of charge to agricultural customers in some states, leading to over-consumption of electricity and under-investment in energy efficient equipment. Blackouts occur frequently during peaking hours, when the power system is capacity constrained, and financially unable to expand capacity to prevent such occurrences. There are serious political barriers to changing the tariff structure. Examples would include India, Pakistan and the Dominican Republic. In the last country, rate subsidies are granted to poor customers in some designated areas.

### 2.1.4 Regional Scenario 4

This scenario includes countries with very high electrification levels, but where the willingness to pay for electricity is very low, rates are heavily subsidized and energy is used very inefficiently. Some of those countries have privatized their utilities, with limited results. Utilities operate in an environment where property rights are not enforced. Simple tasks such as metering and billing for energy based on actual consumption are difficult to achieve. Energy waste is also observed in other areas, such as district heating. Utilities have tried to realign prices, but have faced resistance from public institutions and from the regulators. Countries in this group include many of the Former Soviet Union (FSU) Republics and the countries of Eastern Europe.

## 2.2 Dynamic pricing across the regional scenarios

There are distinct differences between the regional scenarios, arising from inter-country differences in the level of economic development and stage of power sector reform. The more advanced economies have high levels of electrification while others have very low levels of electrification. Some have unbundled and privatized their utilities, so that distribution utilities operate as independent utilities while others have kept their utilities intact as vertically integrated entities that operate either as a government department or a government-owned company. Some countries have developed technically sound methods of dispatching power plants and running power pools. A few have successfully introduced competition in wholesale markets and operate day-ahead and hour-ahead spot markets. One or two are planning to introduce retail competition and choice of provider.

A key point to note here is that from the point of view of implementing pricing reform, the similarities across the four regional scenarios are greater than the differences. In most cases, the factors feed on each other in a vicious circle. In the poorer countries, low per capita incomes lead to low willingness to pay for electricity. In such countries, a culture of entitlements is often to be found that regards electricity as a free public good. This culture, nurtured by a long history of tariff subsidies, absence of meters and institutionalized theft of power, often triumphs over the establishment of property rights for the electric utility.

There is a social and political expectation that electricity should be provided below cost to all citizens. Because tariffs are low, there is no incentive for using energy efficiently. Utilities teeter on the brink of insolvency and are unable to invest in new capacity. Quality of service remains poor and blackouts are a frequent occurrence during the peak season. All of these factors create power shortages and represent a critical infrastructure bottleneck that impedes economic development.

One way for dealing with power shortages is to implement DSM programs. However, in several cases, customers have no incentive for buying energy efficient equipment, since it is more expensive than inefficient equipment and the period over which they can recoup their incremental investment is very long, given the low, subsidized rates for electricity. At the same time, there is often no mechanism for rewarding utilities to undertake such programs either, and they remain reluctant to go down a path that would reduce their revenues and earnings. DSM can be implemented by government agencies that have independent funding sources. Or imposing a fee on the sale of electricity can fund it. However, such “market push” activities are not going to be sustainable over the long haul. What is needed is significant market reform.

India serves as a good example of the reform progress that is underway in South Asia. As noted by Ranganathan-Rao (2004), “electricity reforms in India formally started along with economic liberalization in 1991-92, though the impetus for privatization predates this.” A significant recent step in the Indian power sector was the passing of the new Electricity Act in June 2003.<sup>4</sup> This landmark legislation will contribute to vitally needed access expansion and includes: (1) open access provisions which eliminate licensing requirements for many generators and rural distribution; (2) commitment to reduce and eventually phase out cross-subsidies between rate classes; (3) strict new provisions dealing with electricity theft by consumers and corruption by utility employees, including the mandatory use of meters for all customers within two years; (4) specific goals for stemming fiscal drain and reducing the operating costs of the state electricity boards (SEBs); (5) creation of a new central independent regulator (CERC) with national tariff setting authority; and (6) the requirement for new policies to deal with stand-alone systems for rural areas based on renewable and non-conventional energy sources and to develop a five-year plan for rural electrification. Progress has also been achieved in the clean fuels sector – with a national commitment to phase out subsidies in the provision of LPG and kerosene fuels. In 2001, a new Energy Conservation Act was passed which paves the way for numerous energy efficiency programs including appliance standards and labeling, energy audits and the creation of an Energy Conservation Fund.

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<sup>4</sup> V Ranganathan and D Narasimha Rao, “Round Table: Power Sector Reforms in India,” *Management Review*, Indian Institute of Management, Bangalore, March 2004.

This omnibus reform package will significantly increase private sector participation in the generation and rural distribution sectors, stem the fiscal drain from state electricity boards (SEBs), and create incentives for more efficient energy use, making the sector more capable of meeting an ambitious national electricity plan that includes 50,000 MW of new hydroelectric capacity, 100,000 MW of new thermal capacity and a five-year rural electrification goal of 100,000 villages and 10 million households. The program objectives fit into the power sector reform strategy in that they aim to reduce technical and monetary losses.

How could dynamic pricing of electricity complement power sector reform activities?  
This is taken up in the next chapter.

## Chapter 3 - Dynamic Pricing in a Restructured Power Market

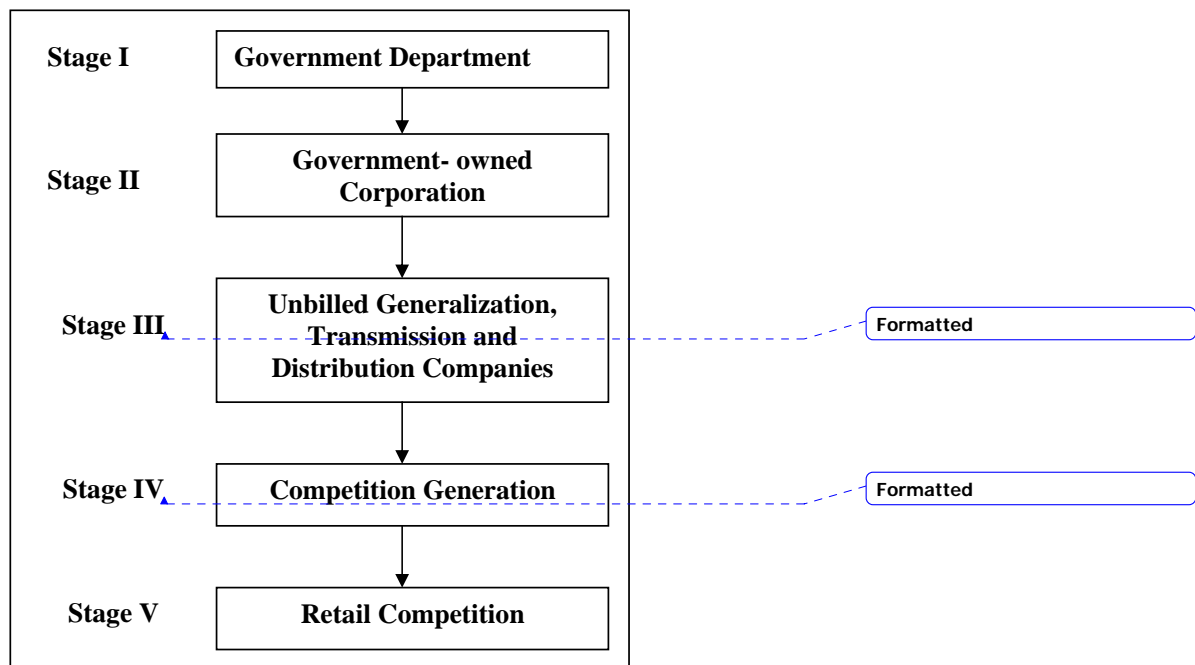
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The restructuring of power markets is a global phenomenon. It has been implemented in varying degrees in developing and emerging economies in order to achieve efficiencies in the production and delivery of electricity.<sup>5</sup> How does market restructuring affect the pace of pricing reform in general and dynamic pricing in particular?<sup>6</sup> There is of course no single answer to this question. It all depends on the manner in which market restructuring is implemented. To answer this question in this report, in this chapter we lay out a stylized restructuring process that embodies features shared by many countries.

### 3.1 Stages of Market Restructuring

The five major stages of market restructuring are shown in the figure below.

**Figure 3-1**  
**Stages of Market Restructuring**



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<sup>5</sup> There is a vast literature on the subject of restructuring power markets. See, for example, the essays in Chao-Huntington (1998), Crew-Schuh (2003), Newberry (1999), Robinson (2001) and Srivastava-Sarkar (1999).

<sup>6</sup> On the topic of pricing reform, many of the principles are not unique to electricity. It is useful to consult the modern literature on market-based pricing designs, which highlights the role of price elasticities in pricing. See, for example, the methodological discussion and case studies in Dolan-Simon (1996), Munroe (1990), Nagle-Holden (1995) and Wilson (1994).

In the first stage of market restructuring, a government department is responsible for generating, transmitting, distributing (and retailing) electricity. In other words, the electric utility is a vertically integrated entity run by the government on non-commercial terms. Often, the entity is losing money, unable to invest in new facilities and reliability is low. The government is concerned about future power shortages that may act as a drag on economic growth and prevent the achievement of its social and political objectives. Private investment is viewed as an essential ingredient in the successful development of the power sector. However, before private investment can be secured, the utility would have to be put on a sound financial footing. Often times, the best way to accomplish this is to convert the electricity department into a government-owned corporation.

Thus, in the second stage, the department is converted into a government-owned corporation with financial accountability. It is given the task of making itself self-sustaining as a prelude to privatization by reforming its business practices. This involves benchmarking the corporation's various businesses and engineering functions against international standards. In addition, it often involves tariff reform to ensure that revenues cover costs.

In the third stage, the vertically integrated corporation is divided into generation, transmission, and distribution corporations. The corporations continue to be government owned but are substantially reorganized and run according to modern management principles. Accounting and functional separation is implemented in this phase between the various companies. In addition, they may be legally unbundled and become subsidiaries of a new holding company. At some point, some portion of the shares of the holding company may be offered to private investors, converting it into a mixed state-private ownership entity.

In the fourth stage, some or all of these entities may be privatized. Alternatively, privatization may be held off until competition is allowed into the generation business. A single-buyer model may be created whereby the transmission corporation would buy power from various private generators and sell it to the distribution corporation. Vesting contracts may be created with the legacy generation company and power purchase agreements signed with new, privately owned generators. This model has been implemented in Thailand, Philippines and in many Eastern European countries.

Alternatively, a multiple-buyer market model can be implemented. This would allow large, qualified buyers to contract directly with generators for purchase of electricity, subject to transmission constraints. Distribution companies can be buyers in this model, as long as energy is purchased at transmission voltage from generators. This model has been implemented in France and Latin America.

Finally, a wholesale power market could be created, involving day-ahead and hour-ahead transactions. This would involve multiple buyers and sellers, and dispatch on the basis of bid prices, not costs with time-varying prices. Such an arrangement would allow for spot price contracts in the wholesale market and contracts for various hedging instruments in a separate financial market. There is no requirement to purchase exclusively from the transmission system. The distribution corporation would be able to shop around for alternative generators. This model has been implemented in California and England and Wales.

In the fifth and final stage, retail competition is allowed into the market. The distribution corporation becomes purely a wires company that moves the power through the distribution grid. Retailers procure the power from generators either through bilateral contracts or through a wholesale market and resell it to customers. The distribution company remains responsible for customers who want to buy bundled power. It can either sell the power to them at the wholesale spot market price or sell a menu of pricing products to them with varying premiums for hedging against price volatility. Efforts to simply pass through wholesale spot prices to customers have been a disaster, as borne out by the experience of California and Ontario. There is very little retail demand for such an un-hedged product.

Retail competition has encountered significant difficulties in many developed countries leading some to question its viability, especially in developing and emerging economies. It has succeeded in some markets, such as those in England and Wales, Australia, New Zealand and possibly in some states in the United States such as Ohio, Pennsylvania and Texas. Often times, it has resulted in re-aggregation of customers and vertical re-integration of generation with retailing. For example, in New Zealand, retail is owned entirely by generation companies. This is also true in much of the England and Wales market. In Australia, retailing is seen as a good business if properly hedged with peaking generators that are owned by the retailer.

### **3.2 Implications for Dynamic Pricing**

Regardless of the manner in which a country implements industry restructuring, tariff reform is a *sine qua non* of creating a competitive power sector. As it considers different models for reforming its tariffs, the electric utility will find it useful to assess the economics of dynamic pricing. The electric utility could be a government department, a vertically integrated corporation or an unbundled distribution company. In all cases, from a national perspective, dynamic pricing will create benefits in the form of avoided generation, transmission and distribution costs. However, the benefits in their entirety would only accrue to the electric utility if it were a vertically integrated entity. If it is just a distribution company, it may only be able to count the benefits of avoiding distribution system upgrades. However, the transmission company would be able to count the benefits of avoiding transmission system upgrades and the generation company (or companies) the benefits of avoiding peaking generation capacity.

Having said that, some allowance would have to be made for the specific regulatory situation and stage of market restructuring facing an electric utility provider. The table below shows how the benefit categories that are available for evaluating demand response (DR) in a regulated market may differ from those that might be available under a deregulated market.

**Table 3-1**  
**DR Program Benefit Categories Under Regulation and Deregulation**

	Program Benefits
Regulated Market	<ul style="list-style-type: none"> <li>• Direct capacity benefits when operated or bid</li> <li>• Associated energy benefits</li> <li>• Reduced capacity obligations</li> <li>• Reliability Insurance value</li> <li>• Network or T&amp;D congestion benefits</li> <li>• Value of price spike hedging</li> <li>• Customer option value</li> <li>• Associated energy efficiency benefits</li> </ul>
Deregulated Market	<ul style="list-style-type: none"> <li>• Direct capacity benefits when operated or bid</li> <li>• Associated energy benefits</li> </ul>

Another issue is how would a third party or unregulated utility affiliate use the cost-benefit tests. DSM. The provider would be expected to act like a commercial enterprise and evaluate the economics from a profit and loss perspective. It would have no social obligation to serve. Thus, one could argue that it would operate outside the “evaluation space” defined by the standard practice tests. This does not mean that those tests would not be applied a government agency charged with evaluating the efficiency of the electricity market and to suggest directions for reform.

Recent developments focused on the possible DSM benefits in Ancillary Services Markets (ASM) are also worthy of mention. For example, ISO New England has embarked on a pilot program to demonstrate the feasibility and practicality of DR bidding into Contingency Reserve markets. Furthermore, the bellwether US ISO PJM will soon propose significant changes to its capacity market, to be in place by mid-2005. The new capacity market, to be based on a Reliability Pricing Model (RPM), should create new sources of value for demand response programs including Active Load Management (ALM).

The RPM-based capacity market features most promising for ALM include:

- Locational capacity costs
- Unhedgeable congestion
- Ancillary services, including spinning reserve and contingency reserves
- Operational needs, including load following and supplemental reserves.

It is not necessary to have retail competition in order to benefit from dynamic pricing. In fact, two of the world’s leaders in dynamic pricing, EDF in France and Georgia Power in the United States, are vertically integrated utilities. EDF is government owned and Georgia Power is privately owned.<sup>7</sup> Both have implemented dynamic pricing in markets based on their system marginal cost estimates. Thus, it is not necessary to have

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<sup>7</sup> Their pricing programs were reviewed in the DSM Primer.

competition between suppliers in either wholesale or retail markets in order to have dynamic pricing.

In fact, many of the benefits of retail competition can be realized by having competition between pricing products.<sup>8</sup> Such competition can make up for the lack of competition between service providers. Much has been written on the failures of retail competition. Some have argued it does not create any economic value added from either a customer or provider perspective. At the same time, it creates additional infrastructure costs related to the formation of retailers and associated billing and settlement systems. In many markets when retail competition was introduced, it became a battle for market share based on who would offer the lowest price.<sup>9</sup>

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<sup>8</sup> See the papers in Shmuel S. Oren and Stephen A. Smith, *Service Opportunities for Electric Utilities: Creating Differentiated Products*, Kluwer Academic Publishers, 1993.

<sup>9</sup> Many case studies are surveyed in Ahmad Faruqi and Bob Malko (editors), *Customer Choice: Finding Value in Retail Electricity Markets*, PUR Reports, 1999.

## Chapter 4 - The Five Phases of Pricing Reform

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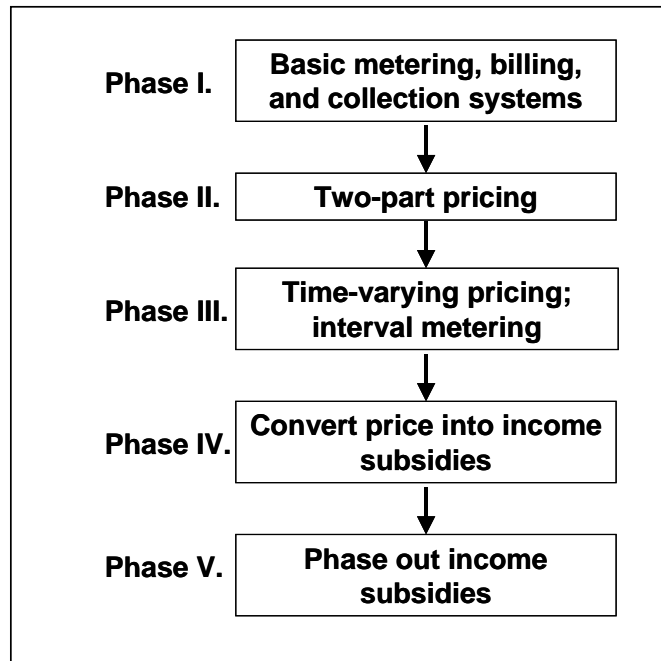
As was discussed in the DSM Primer, utilities have often used cash rebates to improve the balance between demand and supply resources, especially for enhancing the energy efficiency of end-use consumption. However, while they can be useful for “jump starting” the market for energy efficient products, they cannot be sustained over the long haul because of the large expenses involved in their execution. It is much better to transform the market place by influencing the various elements that comprise the value chain of end-use consumption through government codes and standards for appliances, buildings and process equipment and by providing financial incentives to manufacturers, wholesalers and retailers. Market transformation activities can be boosted by creating energy service companies (ESCOs) that can work directly with end users to improve energy efficiency. Some of these activities are highlighted in several case studies of how energy efficiency activities are being carried out in developing countries that were developed to provide background for this report.

If the primary focus is on improving load factor and deferring the installation and upgrading of new generation, transmission and distribution capacity, it is much better way 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.

### **4.1 The Five Phases**

As argued in the DSM Primer, the successful implementation of pricing reform requires a time-phased approach so that neither confusion nor alarm is created in the energy market place. Such an approach also helps 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 4-1.

**Figure 4-1**  
**Phases in Pricing Reform**



*In Phase I, a foundation would be laid 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, so it is best to put them in rather than to put in standard meters that have very limited functionality. 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 currently have an existing meter.

As an example, it is useful to review the experience of Eletrobras/PROCEL in Brazil. This company made the installation of single-phase kWh meters in un-metered, low-income households a priority, leading to both a reduction in electricity use and additional revenue for the distribution utility. Local utilities organized an international bidding process that resulted in some 1.5 million meter installations and annual electricity savings of 710 GWh.

The linkage between energy efficiency and poverty was not a focal point in the project design, although PROCEL once had a strong track record in working with distributors to install meters on poor customers and providing compact fluorescent lamps (CFLs) as a promotion program for helping poor customers manage their bills. Continuing rate increases are certain to be a regressive effect on those who are at or below the poverty line. Coelba Endesa in the Northeast provides the example of a distributor who has invested at the customer's premises in simple improvements such as light switches to either reduce losses or increase efficiency. Regardless of whether the energy is stolen or simply not metered, the customer's demand is absolutely inelastic and the improvement reduces the amount attributed to non-billed energy. Investments like this that are able to reduce technical and non-technical losses have been perceived as "win-win" outcomes by distributors and can be regarded as model for developing countries.

Another example can be found in the Indian state of Madhya Pradesh (MP). One of the measures stipulated in the Memorandum of Understanding (MOU) requires compulsory metering for all categories of customers. The MOU also requires recovery of unbilled energy, improved theft control and the application of a minimum tariff charge (75% of the supply cost) for any category of consumer. Tariffs for farmers and municipalities in MP are substantially below costs, leading to high losses and creating a precarious commercial environment for utilities. Estimated losses vary widely based on the approach that is used in their estimation. These losses are often hidden within the consumption of unmetered customers. Official historical figures in regards to technical and commercial losses are approximately 33 percent but the figures obtained by correcting the consumption estimates of unmetered customers are approximately 55 percent.

The discrepancies between these figures are caused by the fact that a large portion of unexplained energy usage was just assimilated to unmetered agricultural consumption but this practice just led to figures of consumption by farmers that could not be reconciled with the irrigation season and pumping equipment survey. While improving its knowledge of the sectors through load research activities, the MP State Electricity Board (MPSEB) has revised the initial figures. If we rely on the revised statistics, the technical losses in MP would represent 22.5% of the total consumption while the commercial losses represent 31.4%. Hooking up to low voltage wires is a common practice in villages and rural areas in India and many other developing countries and explains how losses of such magnitude are encountered.

This high level of commercial and technical losses, combined with the problem of unmetered consumption (estimated at 28.2%), creates pressure to increase the tariffs in order for the utility to recover its costs. Metering all consumption would help recover the utility's lost revenues, enabling it to invest in system expansion and improve supply. Simultaneously, it would enhance the efficiency of end-use consumption. Both measures would result in an improved demand-supply outlook.

***In Phase II, a two-part pricing scheme would be implemented.*** In the first part of the rate, the customer would pay the existing rate for a pre-specified level of monthly consumption called "customer base load (CBL)." There are several ways to compute the CBL, with the easiest being to set it equal to 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.<sup>10</sup>

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.

Another example is direct load control of selective customer appliances. For example, studies indicate that electric resistance shower water heaters that are used in some 20 million households in Brazil are a big peak load problem for utilities, with each contributing a diversified coincident demand of 0.4 kW. Eletrobras/PROCEL, working with CEMIG, has developed a load control device that prevents the electric resistance heater from operating during the peak period. This demand limiter reduces peak demand but does not reduce sales, as consumers alter their bathing schedule. In 1997-1998, eight utilities initiated pilot projects to stimulate the adoption of approximately 67,000 demand limiters.

***In Phase III, time-varying price signals reflecting the time-variation in the cost of energy would be introduced.*** Interval meters would be installed on customer premises allowing either the introduction of time-sensitive load curtailment programs or dynamic pricing programs. 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. If the rates were offered as default tariffs, they would have to be revenue neutral with respect to the average class customer. Or they could be offered as a two-part tariff, and be revenue neutral to each individual customer’s CBL. Some of the key analytical steps in implementing this phase are discussed further in Section 4.2.

***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

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<sup>10</sup> Hethie Parmesano, “Making every consumer a market participant,” *The Electricity Journal*, Volume 16, Issue 4, 2003.

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.

## 4.2 Designing Time-Varying Tariffs

As D. J. Bolton noted in his classic work on the economics of electricity, “There is general agreement that appropriate tariffs are essential to any rapid development of electricity supply, and there is complete disagreement as to what constitutes an appropriate tariff.”<sup>11</sup> Nevertheless, over time, it has come to be commonly understood that an appropriate tariff should reflect the long-run marginal cost of electricity.<sup>12</sup> Given the non-storable nature of electricity, there is considerable diurnal and seasonal variation in electricity costs. Thus, appropriate tariffs should feature multiple pricing periods and have a time-varying character. A variety of such tariffs were discussed in the DSM Primer.

All time-varying tariffs are designed through a process that involves a number of common steps. The first step typically involves an assessment of the economic efficiency gains by rate class (e.g., residential, small commercial and industrial, agricultural and so on) and market segment (e.g., single family homes, apartment buildings, schools and colleges and so on). This task involves estimating the current load shape by rate class and market segment. A statistically representative sample of load research customers is required to develop these load shapes. Within each rate class and market segment, it should identify how much energy the typical customer consumes by rate period during the peak month, which could be a summer or winter month. Using the existing tariff schedule, the typical customer’s bill would be estimated.

Second, time-varying rates would be developed that would leave the typical customer’s bill unchanged in the absence of any changes in the customer’s usage pattern. Such rates are called “revenue neutral” rates in technical parlance.<sup>13</sup> It would be useful to develop multiple revenue-neutral time-varying rates that feature different peak to off-peak ratios and have peak periods of different lengths. In addition, it would be useful to develop some rates that are static TOU rates and others that are dynamic critical-peak pricing (CPP) rates.<sup>14</sup>

Thirdly, the impact of these time-varying rates on load shapes would need to be estimated. Reviewing the literature and/or adapting the results of other studies to the specific socio-demographic and geographic features of the utility service area that is under study can develop such estimates.

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<sup>11</sup> D. J. Bolton (1950), *Electrical Engineering Economics*, Chapman-Hall, London, 1950.

<sup>12</sup> See the discussion in Monasinghe-Warford (1982) and Turvey-Anderson (1997).

<sup>13</sup> In some cases involving target marketing, one may develop revenue neutral rates for specific groups of customers with above-average peak usage rather than for the class a whole. This would be the case if the rates were to be offered on an opt-in basis. This issue is discussed further in Chapter 6, Frequently Asked Questions.

<sup>14</sup> For definitions of these terms, consult the DSM Primer.

Fourthly, these changes in load shape would need to be valued from multiple perspectives, such as the total resource cost (TRC) test, the rate impact measure (RIM) test, the utility cost (UC) test and the participant bill (PB) test. This would require information on the marginal capacity and energy cost of supplying electricity by time period. It would also require information on the cost of interval meters (and associated billing and customer care systems) necessary to support the provision of time-varying tariffs. Programs that fail the PB and TRC tests are unlikely to be considered further. Programs that pass the TRC and RIM tests are sure winners and would move on to the next stage of screening. Trade-offs would have to be made between programs that pass the TRC test but fail the RIM test.

The results would likely differ by customer class and market segment, with some classes and segments being very cost-effective and others being less cost-effective. The following sidebar illustrates this step using data from three North American utilities. At this stage, it would be useful to rank order the classes and segments and use the ranking to prioritize project execution. One way to accomplish this is to plot the TRC benefit-cost (BC) ratios on one axis and the size of efficiency gain (measured either as reduced peak MW or as the value of the TRC test) on another axis. Clearly, programs that have a high benefit-cost ratio and high aggregate benefits would be ranked ahead of programs that have a low benefit-cost ratio and low aggregate benefits. Trade-offs would have to be made between projects that have a high BC ratio but a low aggregate benefit and projects that have a low BC ratio and large aggregate benefits.

Fifthly, if the program appears to pass that combination of tests that are judged to be socially pertinent, the number of customers that are likely to participate in the program would need to be estimated. This will require a decision to be made on whether the program would be made the default rate for all customers (and they would be given the choice of opting out to the standard rate) or whether it would be offered on an opt-in basis. Evidence suggests that a much larger number of customers would participate in the program if it were offered as a default tariff than if it is offered on an opt-in basis.

If it were offered on an opt-in basis, a significant marketing campaign would have to be planned to recruit customers. This would involve advertising, promotion and customer education activities. In addition, it may also require that the utility provide some type of bill protection to customers during the first year of the program. This is done by a number of utilities such as the Salt River Project (SRP) in Phoenix, Arizona. SRP computes the customer's bill two ways, once with the TOU rate and once with the standard rate. If the TOU bill exceeds the standard bill, the customer is billed at the standard rate. Otherwise, the customer gets to pay the TOU bill. Alternatively, the rate could be offered on a two-part basis (see the discussion in the previous section relating to the second phase of pricing reform).

Sixthly, depending on the outcome of the fifth step, the program would be offered on either a pilot or full scale basis to either the entire market or to specific target markets. If there were much uncertainty about results, it would be best to proceed with a pilot program. This would help improve the precision of results. If results were quite uncertain, a full-scale launch would be advisable since the margin for error would be small. If the program were offered on an opt-in basis, it would be best to offer it to a

target market in order to contain marketing costs and maximize program participation rates.

### 4.3 Assessing Cost-Effectiveness by Rate Class

This sidebar presents an evaluation of the cost-effectiveness of time-varying rates for three North American utilities that are called A, B and C. Several rate options are analyzed. One is a traditional TOU rate, with four-time periods and three price levels. Prices vary seasonally. A second rate is a critical peak-pricing (CPP) design very similar to the Gulf Power Good Cents Select rate discussed in the DSM Primer. The CPP rate includes a traditional TOU rate combined with a critical price that is applied to the peak and shoulder time blocks for up to ten days a year, the timing of which is unknown. The third rate, extreme day pricing (EDP), charges a high price for all 24 hours during ten critical days, and a low price for all hours on the remaining 355 days.<sup>15</sup> In order to assess the maximum benefit that could be achieved from more economically efficient pricing, we assumed that each rate would be offered as the default rate for all customers.<sup>16</sup>

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

- *Utility A:* About 900,000 residential customers; winter peaking system with very cold winters and humid summers; high air conditioning saturation; relatively tight supply market with higher marginal energy costs than the other two examples; fixed network, radio frequency automated meter reading (AMR) system already in place; incremental meter reading and data management costs to support TOU and dynamic pricing options equals about \$0.75/customer/month; the ratio of the CPP price to the base price equals roughly 2.75 and the ratio of the peak-period price to the base price equals 1.60.
- *Utility B:* About 1.2 million residential and small to medium C&I customers; summer peaking system with cold winters and mild, dry summers; low saturation of air conditioning; relatively low marginal energy costs; low-cost existing metering operation; estimated incremental capital and operating costs for new AMR system between \$1.60 and \$3.00/customer/month; the ratio of the CPP price to the base price equals roughly 3.4 and the ratio of the peak-period price to the base price equals 1.75.<sup>17</sup>

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<sup>15</sup> This unusual design was conceived to take advantage of existing meter reading practices at selected utilities that already have AMR systems and receive daily reads. For a utility that fits this profile, which was the case for Utility A, the incremental meter reading and data management costs for such a pricing option are quite low.

<sup>16</sup> For utility A, additional analysis included examining a voluntary TOU rate with one-third market penetration, and a large-scale air conditioning direct load control program. Both options had substantially lower net benefits than the dynamic rate options. The voluntary program showed relatively small benefits while the direct load control program had benefits much smaller than the dynamic pricing options but more than twice the benefits of the mandatory TOU rate.

<sup>17</sup> The results presented here are based on the lower cost estimate. Net benefit estimates based on the high-end cost estimate are still strongly positive for dynamic pricing options but not for the TOU rate.

- *Utility C*: About 1 million residential and small to medium commercial customers; winter peaking system with moderate winters and cool summers; low saturation of air conditioning; relatively low marginal energy costs; fixed network, radio frequency AMR system already in place; incremental meter reading and data management costs required to support TOU and dynamic pricing options equals about \$0.91/customer/month; the ratio of the CPP price to the base price equals roughly 2.17 and the ratio of the peak-period price to the base price equals 1.31.

Each rate option was evaluated on several different cost-effectiveness tests.<sup>18</sup> Our primary focus is on the total resource cost (TRC) test, which examines overall resource efficiency by comparing benefits measured as avoided energy and capacity costs with the costs of achieving them, which consist primarily of incremental metering and billing costs and investments by consumers in enabling technologies, such as programmable thermostats. Marginal energy costs used in the analysis vary by time period and utility, and range from a low of around 2¢/kWh during the economy period in the winter to a high of more than 10¢/kWh during the critical period in the summer or winter. Marginal generation capacity costs vary across utilities. The analysis for utilities A and B used a marginal generation capacity value equal to \$47/kW-year whereas utility C used a value of \$59/kW-year. Marginal capacity costs for transmission and distribution combined equal \$30/kW-year for utilities A and B and \$53/kW-year for utility C.

Figure 1 shows the present value of net benefits for residential consumers.<sup>19</sup> The dynamic pricing options show much larger net benefits than the TOU option. Benefits for the TOU rate option are still attractive for utilities A and C, largely because these companies already have AMR systems in place and only must pay the incremental cost of obtaining TOU reads from these existing systems. Utility B, on the other hand, must install a new metering system in order to implement any of the rate options.<sup>20</sup> Given these higher incremental costs, the net benefits for standard TOU pricing are, at best, breakeven.

Importantly, in spite of these higher incremental costs, net benefits for the dynamic pricing options for utility B are still large, equaling \$333 million for the CPP rate and \$235 million for EDP. Net benefit estimates for dynamic pricing for utility A, with its lower incremental costs, are extremely attractive, equaling more than \$700 million for CPP and almost \$550 million for the EDP rate. The results for utility C, which also has an existing AMR system, are similar to those for utility A, with net benefits for the CPP tariff equaling almost \$500 million.

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<sup>18</sup> See the appendix to the DSM Primer for a definition of terms and concepts.

<sup>19</sup> The results presented in Figure 1 represent net present values over 20 years for utilities A and B and 10 years for utility C.

<sup>20</sup> Because of the need to install a new metering system and an assumption that no consumer will be placed on a new rate until all meters are installed, the cost stream for Utility B starts roughly three years before the benefit stream. If regulators would allow customers to be placed on the new rates as meters are installed, the timing of the benefit and cost streams would coincide and net benefits would increase.

**Figure 4-1  
TRC Net Benefits For Residential Consumers**

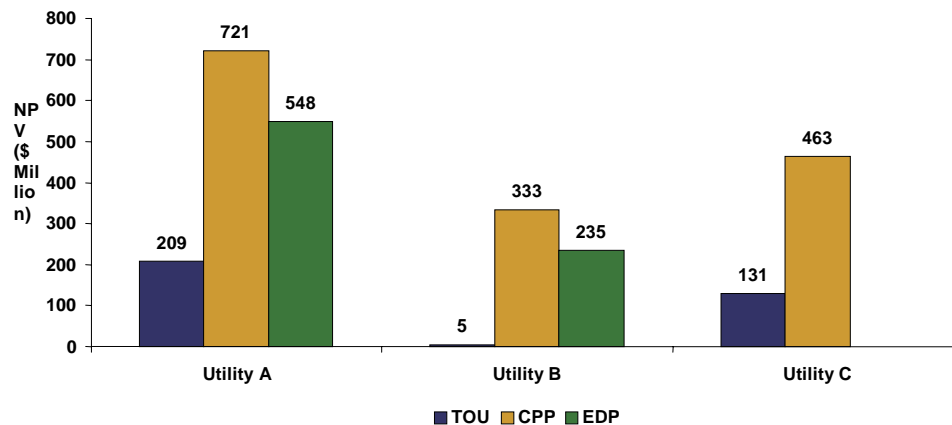


Figure 4-2 shows the results for C&I customers for utilities B and C.<sup>21</sup> In the aggregate, small to medium C&I customers follow a pattern similar to that of residential customers, with the dynamic pricing options showing much larger net benefits than standard TOU rates. However, these aggregate benefits mask important differences between small and medium C&I consumers. As indicated by the results for utility B, all rate options show marginal benefits for small C&I consumers, whereas benefits are relatively attractive for medium consumers. As indicated previously, price elasticities for C&I consumers are only about one-quarter the value for residential consumers. However, this lower responsiveness is offset by the much larger load associated with medium C&I customers. For small C&I consumers, on the other hand, low usage combined with low responsiveness means that the benefits of load shifting are insufficient to offset the incremental metering and data management costs associated with TOU or dynamic pricing.

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

<sup>21</sup> C&I consumers were not analyzed for utility A.

**Figure 4-2**  
**TRC Net Benefits for C&I Customers**

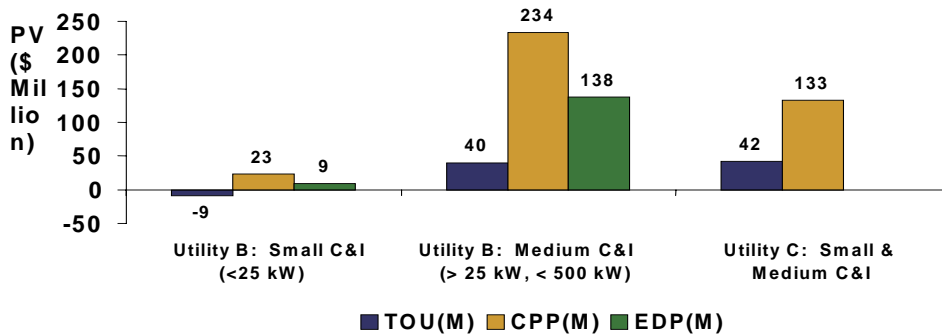
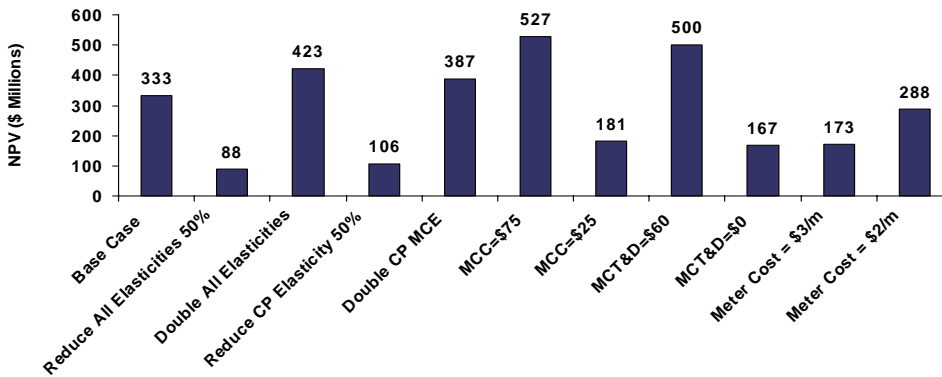


Figure 4-3 shows the results of selected sensitivity tests performed on the residential market segment for the CPP rate for utility B. We present results for the residential sector because net benefit estimates are more sensitive to changes in key drivers for this segment, because of high price elasticities and the fact that total incremental metering costs are quite large relative to other segments (because of the large number of residential customers compared with C&I customers). Although the TRC test is quite sensitive to changes in key variables, net benefits remain positive across a wide range of sensitivity tests for this dynamic pricing option. Starting from a base result of \$333 million, net benefit estimates range from a low of \$88 million under the assumption that customer responsiveness is half of that assumed in the base case, to a high of \$527 million if marginal generation capacity costs are increased from \$47/kW-year to \$75/kW-year. Importantly, the net benefit estimates are still positive and reasonably attractive even when incremental metering costs are at the high end of the cost range or when marginal capacity cost values is substantially reduced. In other words, the results are robust across a wide range of assumptions.

**Figure 4-3**  
**Residential CPP TRC Net Benefits**



#### 4.3.1 Conclusions

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

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

## Chapter 5 - Applications in Developing Countries

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Time-varying tariffs are widespread in developed countries. Often times, they are mandatory for large commercial and industrial customers and optional for residential customers. The peaks to off-peak ratios are typically steeper for larger customers. For example, in Victoria, Australia, tariffs for low voltage customers have a peak to off-peak ratio in between 2:1 and 3:1. Corresponding tariffs for high voltage customers have a ratio in between 3:1 and 5:1.<sup>22</sup>

Several developing countries have begun to implement time-varying pricing to improve their economics. For example, India's Electricity Act of 2003 provides a strong legal framework for pursuing DSM activities inclusive of TOU rates.<sup>23</sup> The government of India (GOI) has insisted on the inclusion of DSM measures in the memoranda of understanding (MoUs) it has signed with several state governments and utilities under its financial assistance program. Typical MoUs include the following provision:

“An effective program in the field of demand side management through – energy efficient bulbs, tube lights and agricultural pump sets. Time of the day metering and differential tariff for peak and off peak hours needs to be implemented with suitable mass awareness and extension efforts.”

Time-of-day tariffs have also been adopted by several energy regulatory commissions (ERCs), including those in the states of Maharashtra, Uttar Pradesh and Andhra Pradesh. For example, Maharashtra ERC has significantly enhanced the differential in peak and off peak energy charges (being Rs. 1.45 / kWh in March 10, 2004 order). Through its tariff order for 2001-02, UPERC has introduced kWh-based tariff for high-tension consumers. Apart from this, tariff orders of several other commissions, such as KERC and DERC, have paved the way for introduction of ToD tariffs in the near future.

This chapter includes six case studies dealing with China, Thailand, Turkey, Tunisia, Uruguay and Vietnam that are based on research carried out by staff at the World Bank and at the consulting firm of Econoler. Most case studies discuss the implementation of standard TOU rates with varying peak to off-peak ratios. One, that dealing with China, discusses CPP rates. Information is provided on the rates themselves, in the form of prices and number of periods, applicable customer segments, and in a few cases, on the impact of these rates.

Four key lessons emerge from the case studies. First, it is necessary to build the rates so they are not only good for the utility, in terms of achieving reductions in peak loads, but also good for the customers, in terms of reducing electricity bills. The key is to design

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<sup>22</sup> Victoria Government Gazette, October 29, 2004, Numbers S 222 and S 223.

<sup>23</sup> Prayas Energy Group, “Demand-Side Management (DSM) in the Electricity Sector Urgent Need for Regulatory Action and Utility-Driven Programs,” Pune, India, February 2005.

them so that the avoided supply-side costs exceed customer bill savings, which represent lost revenues to the utility.

Second, to obtain higher customer acceptance of the rates, it is best to keep the duration of the peak period as short as possible.

Third, to obtain significant amount of peak load reduction and customer bill savings, it will often be necessary to use a significant peak to off-peak ratio, such as 3:1 or higher.

Finally, it is important to monitor the impact of the rates and to modify them as needed to ensure high levels of customer satisfaction and cost-effectiveness.

### **5.1 Time of Use tariffs in China<sup>24</sup>**

The People's Republic of China has a long history of experience with load management. Recent experience with load management to address power shortages has been especially successful. In the past few years, load management strategies have focused on rapid implementation of TOU pricing, adoption of interruptible tariffs, and deployment of energy storage systems for cooling and heating. The focus is on reducing peak load and shifting use from on-peak periods to off-peak periods. In essence, the new concept of DSM involves the creation of a "cooperative partner" relationship between the electric power consumers and suppliers. The emphasis has shifted from an involuntary approach, which involved government "command and control" measures, such as shut downs of factories and industries, to a more market-driven approach based on price signals and other incentives. The development of energy storage technology to help customers shift loads from peak to off-peak periods has also been very helpful.

As shown below, customers in seven major provinces reduced peak load by over 10 GW in 2003. But only about 30% of the peak load reduction was due to utility load management programs. The remainder was the result of government orders, requests, or advice to enterprises to modify work schedules, maintenance schedules, and production schedules.

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<sup>24</sup> Extracted from *Demand-Side Management in China's Restructured Power Industry: How regulation and policy can deliver DSM benefits to a growing economy and a changing power system*, Draft ESMAP Report, World Bank, August 2004.

**Table 5-1**  
**2003 Peak Load Reductions in China**

Province	Peak Load Reduction (MW)
Jiangsu	2,800
Zhejiang	1,400
Shanghai	1,700
Guangdong	2,250
Hubei	1,000
Hunan	700
Hebei	250
<b>TOTAL</b>	<b>10,100</b>

Over the past ten years, China's DSM efforts have produced significant economic and environmental benefits. The savings are shown below in Table 2.

**Table 5-2**  
**Electricity, Load, Investment, Coal and SO<sub>2</sub> Saving or Reduction in China**

Electricity Saving (TWh)	130.4
Peak Load Shifting (GW)	3.8
Peak Load Reduction (GW)	36.5
Coal Saving (Million tons)	58.6
SO <sub>2</sub> Emission Reduction (Million tons)	1.33

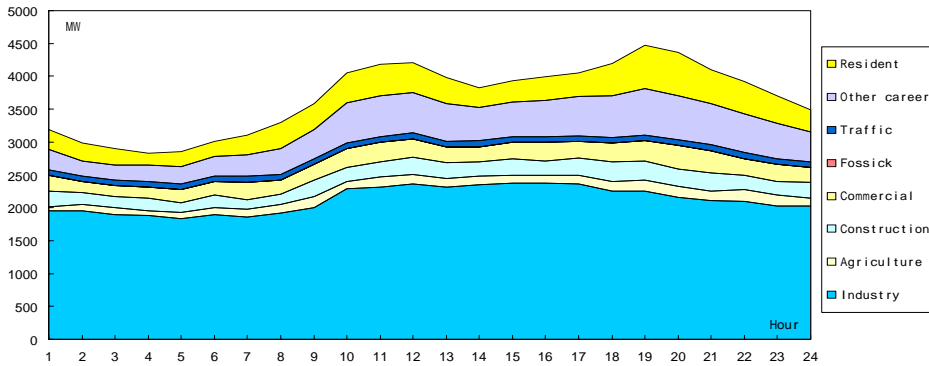
DSM experiences vary by province, as described in the sections that follow. For reference, a map of the provinces appears below.



### 5.1.1 Beijing

In the past ten years, the electric load of Beijing city has grown steadily and rapidly. The peak load increased from 3.01GW in 1992 to 4.47 GW in 1996, at an annual growth rate of 10.4 percent. Peak load has grown faster than electricity sales so the annual load factor has decreased from 86.81 percent in 1992 to 82.31 percent in 1996. Much of Beijing's DSM efforts have been aimed at reversing the decline in load factor.

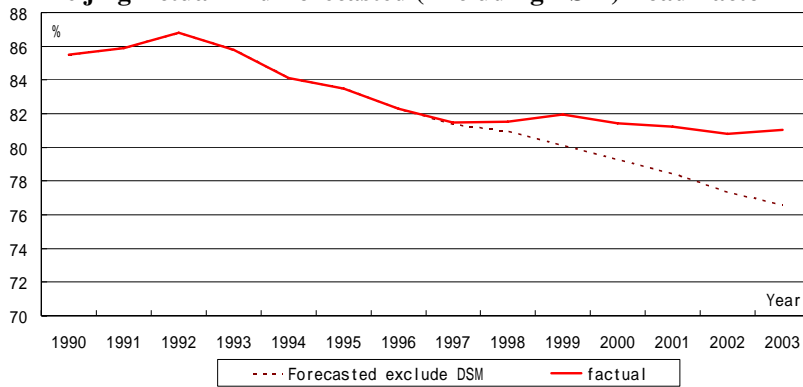
**Figure 5-1**  
**Load Curve of Beijing in 1996**



Before developing peak load management measures, Beijing carried out a survey to determine customer consumption patterns. The survey revealed that in 1996, industrial consumption accounted for over 55.43 percent of total consumption in Beijing. This is shown in Figure 1. Industrial customers accounted for 51 percent of the system's morning peak-load and around 50 percent of the evening peak-load. Residential and commercial customers accounted for about 16 percent of total load and their load factor was about 60 percent.

Figure 5-1 shows the effect of load management on Beijing's load factor. The actual load factor has been maintained at about 81 percent from 1997 to 2003. The figure also shows what the load factor would have been without the load management activities. If DSM were not taken into account, the load factor would have decreased to 76.59 percent in 2003.

**Figure 5-2  
Beijing Actual And Forecasted (Excluding DSM) Load Factor**



In order to capture the peak shifting potentials, the following measures were used in these years:

- Widening the price difference between on and off-peak periods
- Helping enterprises arrange their production plans rationally (for example, maintaining and testing machines should be arranged in peak-load time)
- Setting interruptible load protocols with industry customers, first on a pilot basis, then on a more widespread basis
- Implementing special policies to encourage thermal energy storage systems such as ice-storage air conditioners and heat storage electric boilers

After implementing the above measures, more than 50 MW of peak load was shifted to off-peak periods in 1997, and another 50 MW in 1998. The valley period sales increased by more than 150 GWh in the two years.

The investment in the peak-load shifting was \$ 1.46 million in 1997 and \$ 0.69 million in 1998. The benefits were about \$3 million per year in saved generation capacity costs.

The Beijing DSM project was successful primarily because it focused on load management, which is generally easier to implement than other DSM programs. In many cases, load management can be accomplished with properly designed and progressive tariffs, such as time of use (TOU) and interruptible tariffs. Other DSM accomplishments in Beijing include:

- TOU Rates. By the end of 2003, 77,431 consumers representing 61.69 percent of total consumption were on TOU prices. About 700 MW was shifted by TOU prices. In April 2004, the Beijing Development and Reform Commission decided to widen the difference between the peak and valley tariff. During the summer, the off-peak price was decreased by 11 percent and the on-peak price was increased by between 5.5 and 20 percent.

- Thermal energy storage. Beijing has added 443 ice storage air-conditioning units and heat storage boilers. These devices have reduced peak load by more than 300MW.
- Promoting Electric Heating. Beijing encourages the use of electric storage space heat to reduce the direct consumption of coal in the city. By the end of 2003, 23,175 residential customers had installed storage heat units in more than 9 million m<sup>2</sup>. These units consumed 221 GWh, of which 149 GWh or 67.36 percent was off-peak.
- Using Interruptible Tariffs. Beijing Distribution Company has interruptible load protocols with major enterprises such as Capital Steel Corporation, Special Steel Corporation, and Yanshan Chemical Industry Corporation in the recent year. About 100 MW of peak load may be shifted per year.
- Load Control at Electric Load Management Center. The Wireless Electric Load Management Center in the Beijing Grid has been playing an important role in balancing power supply and demand. The facility has the potential of connecting over 5,000 locations. By 2003, 1,600 locations with 2,800 MW of load were connected and about 500 MW (about 6 percent of Beijing's total load) can be directly controlled.

#### 5.1.2 Guangdong

From September 2001, Duangzhou city and Dongguan city began to use TOU prices for industrial enterprises. The TOU prices were divided into three time periods, a six-hour peak period, ten-hour shoulder or normal period, and an eight-hour off-peak period. The ratio of prices is 1.35:1:0.6. In April 2003, each city in Guangdong began to use TOU prices, which were divided into three-eight-hour time periods. The ratio of prices was widened to 1.5:1:0.5, yielding a peak to off-peak ratio of 3:1. This program reduced peak load by about 500 MW.

By the end of 2003, 68,000 consumers with capacity in excess of 315 kVA had installed multiple-function meters. This represented 95 TWh of energy use in 2003 and 58 percent of energy sales. Like the other provinces, Guangdong province plans to build a load management center to monitor and control the load of these customers.

#### 5.1.3 Hebei

Hebei province (including the southern and northern parts) has a great deal of DSM experience in recent years. Hebei is experiencing a gap of about 3,000 MW between power supply and demand.

Air conditioning load has increased rapidly and now accounts for 2,300MW or 25.2 percent of annual peak demand. Air conditioning electric consumption has contributed to Hebei grid's declining load factor. Off-peak load is now 45% lower than on-peak load. DSM experience in Hebei includes:

- By the end of 2003, the Electric Load Management Center was monitoring load at 4,154 locations. About 4,160MW of load is being monitored and about 1,300MW is under control.
- Interruptible tariffs have been made available to some industrial consumers. Customers are compensated \$ 0.12/kWh for interruptions. In 2003, 36 participating factories took part in this program, and peak load was reduced by about 200 MW.
- There are about 39,540 consumers, representing about 50.2 percent of all the sales, on TOU prices, reducing peak load by about 1,100 MW. In addition, about 80 MW to 100 MW were shifted by the use of ice storage cooling and heat storage and about 50MW was reduced by the use of green lighting. The end of 2003 had installed about 141 sets of ice-saving or heat-saving items with a total capacity of 84.7 MW. About 80MW to 100MW of peak load may be shifted by these units.
- Beginning in 2003, a critical peak price 10 percent higher than the standard peak prices was instituted and the off-peak price for consumers using ice storage was reduced by 10 percent.

In the past 5 years, DSM efforts in Hebei have reduced energy consumption by 4 TWh, saving about 2 million tons of coal, 40 thousand tons of SO<sub>2</sub> and 4 million tons of CO<sub>2</sub> .

#### 5.1.4 Hubei

Hubei province has been encouraging ice and heat storage technology. About 546 units have been installed. Peak load has been reduced by about 80 MW. About 225 GWh have been shifted from on peak to off-peak periods annually.

#### 5.1.5 Jiangsu

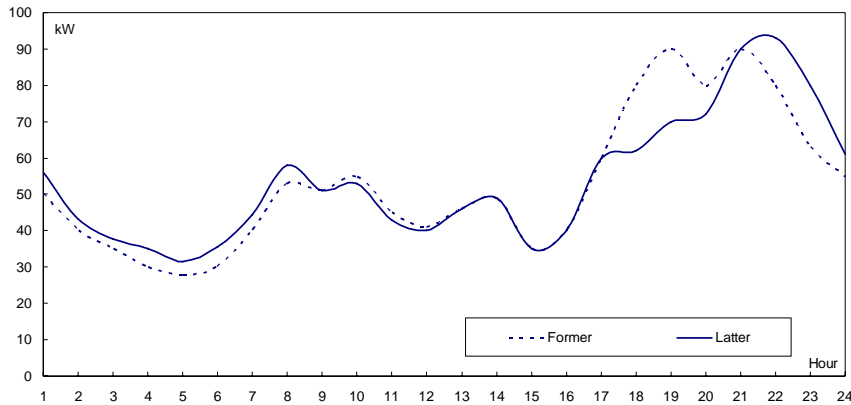
Jiangsu Province has gained a great deal of DSM experience in the past two years. As a result, DSM is now playing an important role in addressing the power shortage. In 2003, the gap between demand and supply in Jiangsu was 3,890 MW. To address this shortage, the government and power corporation implemented the following DSM measures:

- Industrial facility maintenance was re-scheduled to off-peak periods
- Businesses were shut-down and vacations rotated (956 MW)
- Interruptible tariffs (780 MW)
- Voluntary shifted load (592 MW)
- TOU prices. Beginning in August 2003, TOU prices were offered to residential consumers on a voluntary basis. The standard, non-time varying price for residents is 6.3 cents/kWh. TOU prices are 6.7 cents/kWh during the on-peak period from 8:00 am to 9 pm and 3.6 cents/kWh for all other hours.

The utility absorbs the cost of installing TOU meters, which is about \$ 30 per meter. By the end of 2003, about 750,000 thousand families had selected the TOU rate. Figure 3 shows how the load curve of these customers has changed. The time of peak load was deferred about 2.5~3 hours, and about 20% of peak load (about 100MW) was shifted to off peak periods

- Load control system - Electric Load Management Center (475MW)

**Figure 5-3  
Impact of TOU Rates on Residential Load Curve  
Summer of 2003  
Jiangsu Province**



Together these measures have reduced peak load by 2,800 MW. Demand, however, has still exceeded supply by about 1,090MW, so the load control center has imposed curtailments on some customers.

Additional experience in Jiangsu includes:

- From October 1999, industrial TOU prices were applied to six large industries representing 83.12 percent of the total industrial consumption in 2002. The on/off-peak price difference was 3:1. The difference was widened to 5:1 in July 2003. The peak load reduction from this action was about 600 MW. The load factor in Jiangsu increased from 79.19 percent in 1998 to 84.53 in 2003
- About 30 percent of the total peak load in Jiangsu in these years is due to air-conditioners. Jiangsu Power Company has invested about \$ 7.2 million to spread the use of ice-storing air-conditioning. The ice-storing cooling reduced peak load by about 70 MW per day in 2003. For example, Nanjing Yuhua Distribution Company has installed ice storing air-conditioning and heat-storing boilers. This allows 750kW can be shifted from peak to off-peak periods, saving the utility \$37,850 in power costs
- Interruptible tariffs have been made available to some industrial consumers, mainly the steel corporations. Customers are compensated \$ 0.12/kWh for

interruptions. In 2002, five steel corporations took part in the program. Consumers were interrupted 15 times in 10 days for a total of 28 hours. The power corporation paid them \$ 950,000 for these interruptions and they reduced peak load by about 400MW. In 2003, twelve steel corporations took part in this project, and peak load was reduced by about 800 MW.

- In 2002, Jiangsu implemented about 65 DSM projects, including ice storage, heat storage boilers, green lighting, and variable frequency speed controls. The enterprises invested \$ 75 million, with government providing about \$ 5 million an incentive. The peak load was cut by 100MW, energy consumption was reduced by 280GWh and the production cost of the enterprises was reduced by \$ 25 million.
- Communication with about 237 industrial customers (steel, chemical fertilizer and electrolysis) resulted in rescheduling industrial maintenance schedules. Peak load was reduced by 66 MW. In addition, some customers agreed to reschedule their day off from Sunday to Saturday or from weekend to weekday.
- By the end of 2003, each city had built an Electric Load Management Center. These centers monitor and can control the use of about 20,000 industrial machines with a total monitored load of about 11,230MW. About 4,590MW of demand is under control. For example, the Electric Load Management Center of Nanjing Distribution Bureau was built in 1997 at a cost of \$ 8.6 million. The annual operating cost of the center is \$ 240,000 per year. The Center allows Nanjing to monitor 2,430 MW or 71 percent of the district's total load. The Center has direct control over 600 MW or 18 percent of the maximum load. In 2003, the Center shifted enough demand to avoid serious outages.
- In 2002, Jiangsu implemented 65 peak load control projects at high-consumption industries. The projects reduced peak demand by 100 MW and reduced energy use by 280 GWh. Industrial power costs were cut by \$ 20 million per year.
- Energy intensive consumers pay a capacity charge and an energy charge. The capacity charge is either based on actual demand or the transformer capacity. If the customer chooses to be charged on the basis of actual demand they will have an incentive to control peak use. For example, Nanjing Steel Corporation used a computer control system to limit their maximum demand to 50MW from 70 MW (the transformer capacity is 90 MVA). Their power cost was reduced by about \$ 500,000 per year.

In total, Jiangsu's DSM efforts reduced peak demand by about 2,000 MW in 2002 and 3,000 MW in 2003. These efforts saved about \$ 1.21~1.81 billion investment in new coal plants. Annual energy savings are about 2,300 GWh, equal to about 1 MT coal and 23 thousand tons of SO<sub>2</sub>.

#### 5.1.6 Shanghai

In 2003, the difference between on-peak and off-peak prices was increased from 3.5:1 to 4:1. In July, August and September of 2003, many customers were given a load use limit. Electricity consumed within the limit was at the normal price. For use above the limit, the electricity price was much higher. This practice reduced load by about 80 MW.

Further price reforms were instituted in December 2003. Under these reforms, a number of changes were made. First, the distance between the price of each voltage level was widened. Second, the ratio between the peak and off-peak price was raised to 4.5:1. Third, the price for high-consumption industries was increased. And fourth, the capacity price in the two-part tariff system was raised from \$ 2.18 /kW-month to \$ 3.26 /kW-month (based on the maximum demand).

Shanghai's Electric Load Management Center was able to monitor and control about 250 MW in 2003 and 350 MW in 2004. During the period from 1 to 3 pm, the maximum load of large customers must be lower than 90% of their daily maximum demand; otherwise, the electric price will be doubled.

### 5.1.7 Zhejiang

Most factories in Zhejiang Province are mid-size or small. In 2003, about 3,800 factories participated in load management programs and about 1,600MW were reduced.

In 2003, TOU prices were implemented for 34,582 consumers representing about 60 percent of all sales. The critical-peak/off-peak price difference and on-peak/off-peak price difference are 3:1 and 2.2:1 for large industrial users, and the ratios are 2.6:1 and 1.8:1 for other normal industrial users. Through these measures, the load factor in Zhejiang has been kept at about 95 percent in recent years.

## 5.2 Time of use pricing in Thailand<sup>25</sup>

### 5.2.1 Historical Background

In December 1991, the Cabinet endorsed a resolution presented by the National Energy Policy Council on the improvement of Electricity Tariff Rates. The objectives of such an improvement were:

- To have actual economic costs of production reflected by the tariff and to promote efficient use of energy, in particular to promote lesser use of electricity during the peak period of the system, which will help reduce the long-term investment in power generation
- To stabilize the financial status of the Power Utilities (PUs) and to enable the PUs to expand their operation in the future;

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<sup>25</sup> The rates presented in this case study are obtained from the website of the Metropolitan Electricity Authority, [http://www.mea.or.th/english/tariff/mormal\\_ET.htm](http://www.mea.or.th/english/tariff/mormal_ET.htm), and the text is excerpted from information in the paper, "Electricity Pricing-Thailand," posted at [www.apecenergy.org.au/welcome/background/regulators/Thailand\\_TP\\_1997.pdf](http://www.apecenergy.org.au/welcome/background/regulators/Thailand_TP_1997.pdf). For additional background, consult Chapter 3, "Electricity Tariffs in Thailand," in Turvey and Anderson (1977).

- To provide fairness to various types of power users by means of cross subsidy
- To permit greater flexibility in adjusting the tariff and to have such adjustment made automatically so as to correspond with fuel prices that fluctuate according to the increasingly competitive fuel markets.

### 5.2.2. The Establishment of the 1991 Electricity Tariff Structure

The current tariff structure has been established since the end of 1991, taking into consideration system marginal costs, customer load patterns, revenue requirements of the power utilities and a desire to have a uniform national tariff by customer class (that retain a rate subsidy for small residential customers).

#### 5.2.2.1 Marginal Costs

Marginal costs mean “the additional costs resulting from the most appropriate adjustment of the power generation and distribution systems in order to satisfy the continuously increased demand for power by one additional unit.” The tariff calculated on the marginal cost basis will reflect the power generation and distribution costs, which will convey the correct price signal to consumers and will enhance the efficiency of resource allocation.

#### 5.2.2.2 Load Pattern

Domestic consumption in 1991 could be divided into three periods of time, i.e. during the evening time hours of 6:30 to 9:30 pm when the power consumption was highest (peak period), during the daytime hours of 8:00 am to 6:30 pm when the consumption was moderate (partial-peak period), and during the night-time and early morning hours of 9:30 pm to 8:00 am when the consumption was low (off-peak period). During the peak period, the Electricity Generating Authority of Thailand (EGAT) had to use its full generation capacity until the minimum reserve margin was reached; the Provincial Electricity Authority (PEA) had to use its full dispatching capacity in the same period, whereas the Metropolitan Electricity Authority (MEA) had to maximize its dispatching capacity in the afternoon when the consumption nationwide was at moderate level. Therefore, if the demand had increased during the peak period, the power sector would have been required to increase the investment in power generation and distribution.

Both from an energy efficiency perspective and from an equity of rates perspectives, large consumers during the peak period should pay a higher tariff than small consumers during the off-peak period of the system. One way to determine a fair tariff was to use a formula to automatically adjust the electricity charges in different periods of a day, i.e., implement a Time-of-Day (TOD) Rate. However, this method could not be applied to all individual consumers because the expense for meter installation was rather high. Therefore, it was essential to classify consumers according to their load pattern. Consumers in each category would pay for the tariff according to the rates that most

properly reflected the generation and distribution costs applicable to their respective category.

#### 5.2.2.3 Revenue Requirement of the PUs

These were determined by establishing tariff rates that would yield a rate of return on revalued asset of 8 per cent in a three-year period (1992-1994), taking into consideration PU revenues and expenses.

#### 5.2.3 Time-of-Use (TOU) Rate

The standard bulk supply tariff (BST) structure does not reflect actual power production costs and hence cannot send correct signals to the distribution utilities. Therefore, in order that the BST among the PUs should correspond with the load pattern of the system, it was deemed appropriate to adjust the BST from a Flat Rate to a TOU rate so as to reflect actual costs. This TOU rate is based on the previous average BST, i.e. MEA = 1.4865 Bahts/kWh, PEA = 1.0910 Bahts/kWh. The new BST (TOU) came into effect on 1 January 1997.

##### 5.2.3.1 Retail Tariff

For large general service customers with demand greater than 2 MW, the tariff is in the form of a TOD Rate. For medium general service customers whose demand is lower than 2 MW and whose consumption is over 355,000 kWh/month, the tariff will be in the form of TOD Rate like that of large general service. For medium general service whose consumption does not exceed 355,000 kWh/month, a two-part tariff will be applied, i.e. the tariff will be divided into a demand charge and energy charge. For specific business services, such as hotels, the two-part tariff will be applied. The TOD Rate will be an alternative if the consumption is greater than 355,000 kWh/month.

##### 5.2.3.2 The TOD Rate and its expanded coverage

The TOD Rate is the electricity tariff rate that varies with the time-period during which electricity has been used during the day. Its objective is to shift consumption from the peak to off-peak periods. The TOD Rate was first used in Thailand in 1964 as an alternative rate applied to the industrial sector. In 1966 it became one of the alternative rates for customers that were served directly by EGAT. In practice, only a few customers opted into this rate.

The TOD Rate became compulsory on January 1, 1990 for industrial consumers with peak demands over 2,000 kW. It had three pricing periods. A demand charge of 180 Baht/kW-month was imposed during the peak period. In addition, a charge of 90 Baht/kW-month was imposed on consumption during the partial-peak period. These charges were modified subsequently, as seen in the following table.

The restructuring of the electricity tariff rates in accordance with the Cabinet decision of December 3, 1991 not only made the tariff rates reflect more accurately the actual

marginal costs of production, particularly the tariff rates applicable to the business and industrial categories, but it also expanded the scope of the TOD Rate coverage by including those consumers in the business and industrial sectors whose power demand exceeded 2,000 kW/month or having electricity consumption at over 355,000 kWh/month. This resulted in an increased number of consumers coming under the coverage of the TOD Rate. However, the rate remains voluntary for hotels.

**Table 5-3  
The Time-of-Day Rate in Thailand**

Time of Day Rate	Demand Charge (Baht / kW)			Energy Charge (Baht / kWh)
	Peak (18.30-21.30)	Partial Peak (08.00-18.30)	Off-Peak (21.30-08.00)	
69 kV and over	224.30	29.91	0	1.666
12 – 24 kV	285.05	58.88	0	1.7034
Below 12 kV	332.71	68.22	0	1.7314

In 1994, there were 1,134 large electricity users who could come under the TOD rate. By September 1998, the number had risen to 1,964 of whom 782 were from MEA and 1,182 were from PEA.<sup>26</sup>

In addition to time differential during the day, the TOD Rate also varies by voltage level:

**Table 5-4  
The TOD Rate by Voltage Level in Thailand  
(Baht/kWh)**

Voltage	Peak	Partial Peak	Off-Peak
69 kV and over	3.70	1.13	1.03
12 – 24 kV	4.46	1.27	1.07
Below 12 kV	5.06	1.38	1.10

NB: The average tariff per unit in each period is calculated on the assumption that the consumption is consistent all through each period.

<sup>26</sup> Electricity Generating Authority of Thailand, "Load Management Program Evaluation," draft final report, prepared by Electricite de France, no date.

### 5.2.3.3 The impact of the TOD Rate on system power demand

Major industrial groups covered by the TOD Rate are the textile industry, food processing industry, the agro-industry and the metal, cement, steel and chemical industries. Under the TOD rate, the energy charge is a flat rate but the demand charge varies according to the consumer categories and the time of power consumption. As a result, the application of the TOD Rate has lowered the systems demand during the peak hours by as much as 700 MW.

Business and industrial consumers who can avoid electricity consumption during the peak period have overall benefit from this TOD rate of 20-150 million Bahts per month. On the generation and supply side, EGAT is being able to reduce its long-term investment in constructing new power plants by about 21,000 million Bahts.

A recent survey found that a majority of TOU rate customers are satisfied or very satisfied with the rate and less than a fifth are not satisfied with it. The primary driver for customer satisfaction is whether or not the rate saves them on their electric utility bills. A secondary driver is customer perceptions about having some control over power bills. Among the unsatisfied customers, a primary reason for the dissatisfaction is the high cost of electricity during the peak period and a perception of inability to reduce peak usage. Customers who were neutral about the rate said they did not spend much on electricity as a percent of their total operating costs and were not interested in spending scarce management time trying to save electricity costs. Satisfaction was highest in the food manufacturing and metal/machining industries and lowest in retail/hotel establishments.

### 5.2.4 Time-of-Use (TOU) Rate

The Time-of-Use Rate (TOU) was established as an alternative for users who currently use the TOD rate so that the tariff structure would reflect the costs and load curve of the system. As of September 1998, 167 customers were on TOU rates, of which 11 were in MEA and 156 in PEA.

The TOU rate differs from the TOD rate in the following:

- TOU will increase tariff categories for consumers whose consumption is at or greater than 115 kV; the tariff will be lower than that of the previous 69 kV. TOU will be divided into two periods of time, i.e. peak, from 9 am to 10 pm on Mondays through Saturdays and off-peak during all other hours. Under the TOU rate, the energy charge varies according to voltage levels and periods of time. Under the TOU rate, there is no demand charge during the Off-Peak period.
- The newly established TOU rate will be compulsory for new consumers who have to use the TOD rate. The TOU rate best reflects actual costs of the current power system. This will provide more incentives for consumers to change their consumption behavior, whereas those whose consumption is consistent and who do not change their consumption behavior will not be harmed.

This new TOU rate came into effect on 1 January 1997. About 25 percent of the eligible customers have opted in to the rate. About half of the participants are happy with the rate, and most of who are large and medium customers. As in the TOD rate, retail establishments and hotels are least satisfied with it. The length of the peak period (too long) is cited as a major reason for dissatisfaction.

One fact that emerges from analysis of both the TOD and TOU rates is that customers do not know whether the TOU rate provides any cost advantage over the standard tariff. Tools that can provide them better information about their load shape and methods for reducing peak loads and/or shifting them to off-peak periods would go a long way in attracting customers to time-varying rates.

### **5.3 Time-of-Use Tariffs in Tunisia<sup>27</sup>**

In Tunisia, the gas and electricity energy sectors are operated by a central government corporation called the “Société Tunisienne de l’Électricité et du Gaz (STEG),” which operates under the guardianship of the Ministry of Industry and Energy. It has a customer base of 2.1 million.

STEG offers a time-of-use (TOU) rate to its commercial, industrial and institutional customers. This rate conveys to customers the time-varying natures of electricity costs. Until the year 2000, a morning and an evening peak characterized the load shape on the day of maximum demand in Tunisia. These peak demands were recorded during the winter season. In 1974, the STEG introduced TOU rates to a selected group of high-energy consumers in order to help reduce the progression of the peak demand.

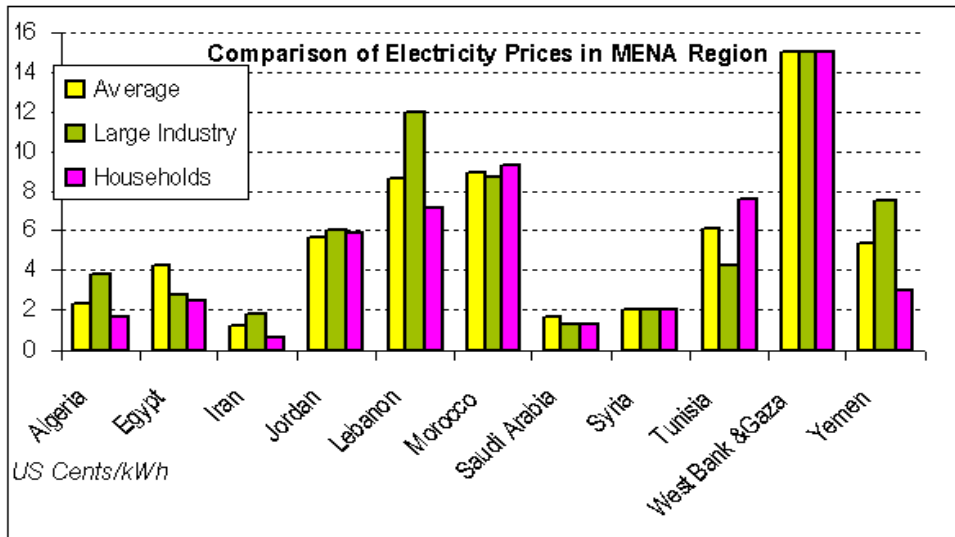
After 2000, the load shape changed drastically. The maximum demand is now recorded during the summer months (June-August) with a maximum peak demand in the middle of the day and a smaller peak in the evening. This change is a direct result of the rapid penetration of air conditioners on the market and their impact on the daily load shape. A new TOU tariff for medium and HV consumers was therefore introduced in 2001 and later revised in 2003.

Tariffs in Tunisia are much lower than those in neighboring countries located in the Middle East and North Africa (MENA), as shown below.

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<sup>27</sup> For a historical survey, see Chapter 4, “Electricity Tariffs in Tunisia,” in Turvey-Anderson (1977).

**Figure 5-4**  
**Comparison of Electricity Prices in MENA Region**



The TOU tariff was introduced as a full-scale project targeting the entire high voltage (HV) and medium voltage (MV) sectors of the electricity market at the same time. The first TOU rates were introduced in 1974 and targeted MV consumers. At that time, it was a mandatory rate and it remained this way until 1980. In 1976, TOU rates were introduced for HV customers. This was a major change in the market as the new rates were mandatory and targeted very large customers including cement and chemical industries. Customers wanting to avoid this new TOU scheme had no choice but to downgrade their energy supply with a lower voltage (LV) connection. The STEG realized, at that point, the importance of leaving the tariff choice up to their MV customers. It therefore reintroduced, in 1980, the flat rate structure and offered their customers the option of selecting the existing TOU rate structure or to switch to the new rate structure as they so desired.

In 2001, following a change in the daily load profile and the peak period time, the STEG reviewed its customer base and decided to modify the TOU program for MV customers who were mainly industrial plants, commercial buildings and institutional facilities. Hotels were identified as an important sub-sector in Tunisia due to the country's significant tourism infrastructure. A new rate was then prepared and introduced that same year. This new rate introduced a fourth time period for energy costs that corresponded to the evening period. However, the industries reacted strongly to this four-period rate. The STEG then agreed to reintroduce the previous 3-shift rate and to focus the new 4-shift rate on the hotel and commercial sector. From that time on, MV customers could select the rate which best suited their activities. This tariff was subsequently modified in April 2003 with an increase in the night rate to compensate for the real cost of generation during various periods of the day.

The following table provides more information on the TOU tariffs introduced and the targeted market.

**Table 5-5  
Evolution of TOU Tariffs in Tunisia**

<b>Year</b>	<b>1974-75</b>	<b>1976</b>	<b>1980</b>	<b>2001</b>	<b>2003</b>
<b>TOU tariff</b>	Medium Voltage, new TOU tariff	High Voltage, TOU unique tariff	Medium voltage, Flat rate	4th shift in addition to the 3 existing shifts	The rate for night is increased by 20%
<b>Implementation mechanism</b>	Mandatory for all the medium voltage customers	Mandatory for all the high voltage customers	An option to the TOU rate	Optional according to customer preference	Mandatory for all the high and medium voltage customers
<b>Target market</b>	MV industrial and commercial customers	HV Industrial customers	MV industrial and commercial customers	For all HV and MV customers	For all HV and MV customers

**Note:**

**High voltage= 90 kV and higher**

**Medium Voltage= between 10 kV and 30 kV**

In the HV sector, the intent in 1976 was to apply the rate structure to as large a customer base as possible. Some exceptions, however, were introduced together with the 2001 TOU structure to remove a number of strategic sectors (for example, the textile industry) from the mandatory customer base.

In the MV sector, after the introduction of mandatory TOU tariffs in 1974, all subsequent modifications to rates were proposed on an optional basis. This approach minimized customer resistance to TOU but was more time consuming in that the customers had to be convinced of the benefits of using this rate structure and, at the same time, of adjusting their energy usage patterns. One of the drawbacks of a voluntary rate scheme is a substantially lower market penetration rate.

To determine pricing levels, the STEG takes the long-run marginal cost of generation into consideration. To determine generation costs, the STEG applies a unitary proxy base approach on the actual investment cost for the peak generation unit (notably the gas turbines) or an approach based on complete generation capacity expansion simulation.

Since its introduction in 1974, the TOU tariff was viewed as being the appropriate instrument to send a proper cost signal to its customers so they could adapt their energy usage patterns to the real price of electricity generation. When tariff implementation was voluntary, the customers were responsible for the meter replacement costs. In all other cases, the STEG took charge of the replacement of the meters.

The STEG has proposed the following rate structure for HV and for MV customers, which is expected to be introduced in May 2005:

**Table 5-6**  
**TOU Tariffs for High Voltage and Medium Voltage Customers in Tunisia**

<b>Tariff</b>	<b>Demand charge</b> <i>(US ¢/KW/mth)</i>	<b>Day</b> <i>(US ¢/kWh)</i>	<b>Peak</b> <i>(US ¢/kWh)</i>	<b>Evening</b> <i>(US ¢/kWh)</i>	<b>Night</b> <i>(US ¢/kWh)</i>
<b>HV, 4 shifts</b>	172	3.3	6.1	4.8	2.6
<b>HV, 3 shifts</b>	172	3.3	6.0	N/A	2.6
<b>MV, Flat rate</b>	21	5.0			
<b>MV, 4 shifts</b>	207	4.0	7.0	5.5	2.8

<b>Rate and season</b>	<b>Time period</b>			
	<b>Day</b>	<b>Peak</b>	<b>Evening</b>	<b>Night</b>
<b>3 shifts:</b>				
<b>April-September</b>	08:00-19:00	19:00-23:00		23:00-08:00
<b>October-March</b>	06:30- 17:30	17:30- 21:30		21:30-06:30
<b>4 shifts:</b>				
<b>June-August</b>	06:30-08:30 and 13:30-19:00	08:30- 13:30	19:00-22:00	22:00-06:30
<b>September-May</b>	07:00-18:00	18:00-21:00	N/A	21:00-07:01

Other expansions of the TOU scheme or associated programs are being considered by the STEG for future implementation.

Considering that the peak demand is increasingly being driven by growth in LV customers, the STEG is considering introducing a new TOU tariff for that category of customers. This new rate will differentiate customers according to their connected load. For up to 13 kVA, they will have access to a special rate and for less than 13 KVA, they will be subject to a different power subscription fee. The expected impact of such new tariffs is a decrease in peak demand of 10% to 20% (around 170 to 350 MW for the entire low voltage market) as well as pressure to contain the increase in peak load cause by residential air conditioning demands.

Besides TOU introduction, the STEG has been implementing different rate-based schemes to improve its load profile on the market.

For over ten years, the STEG had also implemented an interruptible tariff in order to reduce the evening peak demands. The results were negligible since only 2 customers had opted for this particular tariff. This tariff was dropped by the STEG in 2003.

The STEG also established two interruptible tariffs for special applications (3 or 4 shifts depending on customer choice):

- Electric water heater rate. This rate is based on a curtailment of the electricity supply during peak periods. Currently more than 100,000 customers are connected and the rate is very popular in regions where natural gas is not available (around 14 of a total of 21 regions). Electric water heaters are

considered by STEG to be high consumption appliances and alternatives such as natural gas or solar water heaters are encouraged by both the ANME and STEG. The result is that this special tariff is no longer available for new customers.

- MV and LV customers in the agricultural sectors and agricultural pumping systems rate. This tariff is also based on the curtailment of the electricity supply during peak periods. It consists of two tariff levels: day and night. This tariff is also applied to the pumping of drinking water. A common strategy adopted by the water distribution company was to introduce the concept of using intermediary water storage during peak periods together with this preferential tariff.

Presently, the number of STEG HV and MV customers is about 11,000. Among these, 1,000 have opted for the TOU tariff while the remaining 10,000 opted for a flat rate tariff. However, it is important to mention that the energy consumption of the 1,000 TOU tariff customers represents nearly half of the total energy consumption in the MV category. This clearly indicates that the TOU rate is more appealing to large consumers whereas medium and small enterprises show a preference for a simpler flat rate.

In 2004, the STEG created a new Customer Services Department with a dedicated representative in each district. However, these individuals are not making any special effort to market the TOU tariff. On request, they provide a pamphlet to inform customers about the different rate structures. The regional representatives help new customers make their tariff choice based on an evaluation of their energy profile and the expected costs for their new facility.

In general, customers have a very high level of satisfaction with the TOU tariff. A considerable number of these customers are readjusting their operations to minimize their energy bills.

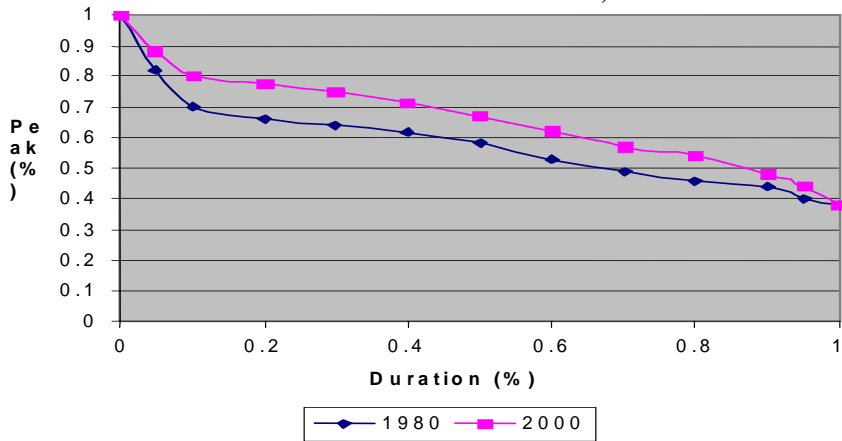
In 2004, the STEG launched a program called "Program CIT" to reach out and communicate with their largest customers. The Program includes an annual overall evaluation of customer satisfaction. However, the STEG is not planning to inform customers on how to take advantage of the TOU tariff to reduce their energy bills. This may, on the other hand, be introduced in the future. The staff in the regional centers is responsible for informing their customers but they currently use a rather informal approach. The STEG is considering how to improve the rate offerings in the future.

The STEG plans to replace all HV and MV meters with electronic meters within the next three years. The new will allow precise monitoring of customer load curves. The information will also be used to help customers determine their baseline usage, as required by the new Energy Conservation Law of August 2, 2004.

The peak demand of the STEG grew almost linearly by 6% between 1980 and 1990 and by 6.3% between 1991 and 2003. The load factor, which is the ratio of electricity generation to the peak demand applied for 8760 hours/year, has increased by nearly 10% from 57% in 1980 to more than 66% in 2000, as shown in the graph below. This indicates an improvement in the Société's load curve profile but it is difficult, in the absence of a

formal evaluation process, to determine what portion of these results was impacted by the TOU scheme and what portion is due to other factors.

**Figure 5-5**  
Classified Load Curve 1980 and 2000, Tunisia

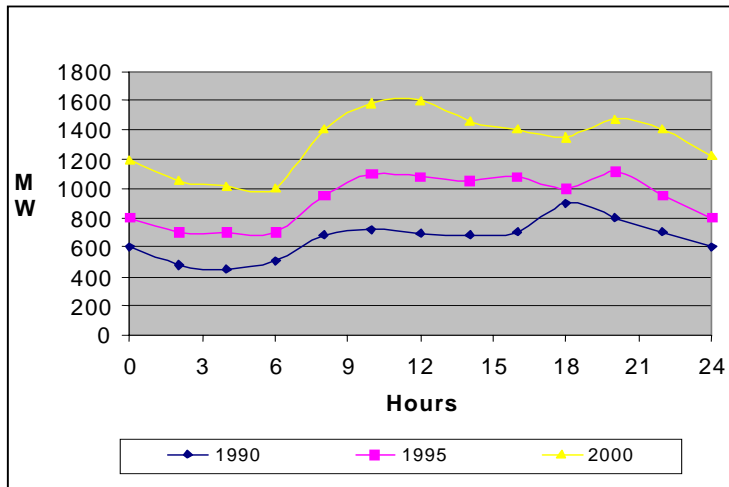


Reference: The Power Sector in Tunisia, Revue Tunisienne de l'Énergie N°56/2001

The evaluation of the individual impacts of the TOU tariff on the load shape is even more difficult to isolate due to the important shift in the load profile caused by the introduction of new end-uses. The gradual shift of the evening peak toward a later hour together with the creation of a new peak around noon during the summer make the analysis of the impacts especially complex since regular load and market research on TOU customers has not been conducted in the past. The following graph compares the load profiles in 1990, 1995 and 2000 and provides a clear indication of the growing importance of the cooling load in recent years.

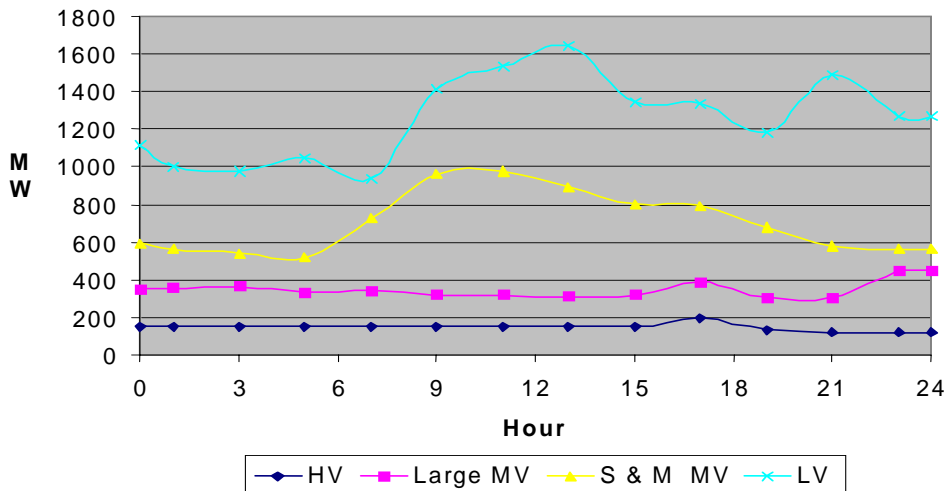
**Figure 5-6**

Evolution of Load Profile in Tunisia



The STEG performed a number of analyses recently to examine the relative impact of the high and MV customers on the network's peak demand. On July 7, 2000, a peak contribution curve was derived from a sample of more than 400 large consumers in the MV category and other information based on customer billing was compiled to create a distributed load profile by category of customer. The results are reported in the following graph.

**Figure 5-7**  
**Synthesis of the Tunisia Load Curve Peak for Summer 2000**



Reference: The Power Sector in Tunisia, Revue Tunisienne de l'Énergie N°56/2001

The curves indicate that TOU tariff customers contribute very little to the peak demand (less than 10% for HV customers and less than 10% for the larger consumers in the MV category). These curves also indicate that the price signal that affects usage is the peak price during the 7 pm to 11 pm timeframe in the case of HV and MV customers.

MV customers account for almost 40% of STEG's total revenue. Within this group, customers supplied with a TOU tariff represent close to 50% of the total energy consumed. HV customers account for 10% of the STEG'S total revenues. The TOU tariff customers (both medium and HV) represent nearly 30% of STEG's total revenue.

Without a careful study, it is difficult to evaluate the impact of the TOU tariff on energy and capacity costs because the load curve is influenced by several other factors including the shift in the evening peak and the creation of a larger peak during the day in the summer as a result of the rapid penetration of air conditioning.

The new peak demand is now during the summer season and coincides with higher ambient temperatures (around noon). The shifting of part of the electricity generation from that peak period to an off-peak period, in response to the introduction of TOU rates, is having a positive impact on the environment. As the specific consumption of the generation units is lower during off-peak periods, no formal evaluation of the environmental effects of the TOU rate structure has been conducted by the STEG.

The TOU tariff also has a positive impact on the economy as it helps to displace part of the investments for the extension of the STEG generation, transmission and distribution network. Without the TOU tariff, higher investments to cope with a higher peak demand would be needed.

The STEG's 30-year experience with the TOU tariff reveals a high level of innovation, commitment and vision to tariff reform. It provides two important lessons:

- Without a formal awareness campaign, the impact of a TOU program is limited to very large customers who have the resources to analyze and take advantage of the TOU rates.
- Important potential for improving economic efficiency lies in the residential and LV segments of the market.
- The full realization of the potential of any TOU rate scheme requires a marketing campaign to recruit customers.

#### **5.4 Time-of-Use Tariffs in Turkey<sup>28</sup>**

The Turkish Electricity Institute (TEK) was established in 1970. In 1980, it took over the generation and distribution facilities owned by municipalities and became a vertically integrated utility in charge of generation, import and export, transmission, system operation, dispatch, distribution and retail sales. In 1994, TEK was unbundled into the Turkish Electricity Company (TEAS), in charge of generation and transmission, and the Turkish Electricity Distribution Company (TEDAS), in charge of distribution and retail supply company.

With the enactment of the Electricity Market Law in 2001, designed to bring Turkey in line with EU Directive 2003/54/EC, the Turkish electricity sector was completely restructured. TEAS were unbundled vertically into three functional companies and the sector was opened to private sector participation and to the gradual introduction of competition in the wholesale and retail markets. The objective of the reform was to create a sector composed of predominantly private sector participants and limit the role of the state to a regulatory one.

A regulatory agency, the Energy Market Regulatory Authority (EMRA), was created. Non-discriminatory regulated third party access to the transmission grid and distribution systems was provided. The Law envisages a bilateral contracting market complemented by a residual balancing mechanism. The preparations to full market implementation are under way. The privatization of the state-owned distribution and generation assets is planned for the period between 2005 and 2009.

Since the mid-eighties, TOU rates have been offered on an optional basis to all customer groups except for places of worship and street lighting. In addition, customers with a contracted load of 700 kW or higher and that are on a two-part tariff are required to purchase electricity on TOU rates.

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<sup>28</sup> For a historical survey, see Chapter 8, "Electricity Development in Turkey: A Case Study Using Linear Programming," in Turvey-Anderson (1977).

The first study was carried by Electricite de France (EDF) and the implementation of TOU rates began in the 1980's. In the 1990's, the tariff structure was further developed, maintaining the basic principles of the earlier TOU rates and introducing a different approach to the treatment of capacity costs. With the reform process and the introduction of the new sector structure by the Electricity Market Law in 2001, new efforts were initiated with the objective of reassessing and updating the tariff structures and making it theoretically justifiable.

EMRA controls all tariffs in Turkey. The TOU tariffs have three pricing periods and these were established based on a review of load shape data. These time periods are Nighttime, between 22:00-06:00, Daytime, between 06:00-17:00, and Peak, between 17:00-22:00.

The ratio of peak to nighttime rates is 3.10 for a sample industrial customer served by Turkish Electricity Distribution Company (TEDAS) in a city that is not a "development priority province"<sup>29</sup>. The ratio between the daytime and nighttime rates is 1.81.

The primary objective of the TOU tariff is to reduce capacity costs by ensuring a more equal distribution of energy consumption both within a given day and within longer time periods. A secondary objective is to ensure that the rates reflect the costs that each customer group imposes on the system.

Price elasticities of demand were not used in the development of TOU rates, which appear to have been developed assuming that customer load shapes will not change in response to the rates. In addition, no impact evaluations have been carried out. Thus, it is not possible to determine how much load has been curtailed or shifted to lower-priced periods. It is likely that the regulator will require the regular collection of such information as part of the monitoring and evaluation activities that will be mandatory after the new market becomes operational.

Such information will be essential to determining the cost-effectiveness of deploying TOU meters, which cost about \$70-80 per residential customer. It will also help in the development of the next generation of DSM programs that integrate economic efficiency considerations with reliability protection considerations.

The Turkish Distribution Code dedicates a section to "demand management" activities by utilities, which are defined as "methods to be applied by the national and/or regional dispatch centers or by the distribution companies, in order to maintain the supply-demand balance." According to the distribution code, "in cases where the generation capacity is inadequate for maintaining system frequency within the range determined in the Grid Code, TEIAS (the transmission company) will coordinate demand management activities performed by the distribution companies." Thus, "demand management" just means load

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<sup>29</sup> This is a special status granted to cities in the east and southeast of Turkey by the Council of Ministers, in order to facilitate economic development in those areas. Investments in those cities enjoy incentives such as reduced electricity rates, exemption from custom duties for imported machinery & equipment, investment allowances, value added tax deferral and investment credit facilities.

shedding, which can take two forms: planned/rotating outages and emergency demand management.

### 5.5 Time of use pricing in Uruguay<sup>30</sup>

A small country of about 3.4 million people, Uruguay is sandwiched between two much larger neighbors, Brazil and Argentina. In 1996, electric service reached 94.2 percent of homes and the total number of customers on December 31, 2000 was about 1.2 million. During the 1993-2002 decade, Uruguay's power consumption grew at 3.3 percent annually. In 2002, Uruguay consumed 7.2 billion kilowatt hours (B kWh) of electricity, down 4% year-on-year, mainly due to a recession. Power generation in 2002 also decreased year-on-on to 9.1 B kWh.

Administración Nacional de Usinas y Transmisiones Electricas (UTE) is responsible for transmission and distribution activities in Uruguay and for most of the power generation. Since 1997, Uruguay's regulatory agency—Unidad Reguladora de la Energía Eléctrica (UREE)—has overseen the country's power market. In December 2002, the government bundled UREE into a larger agency, known as Unidad Reguladora de la Energía y Agua (URSEA). Another 1997 law permitted independent producers to generate power, introducing competition to the sector. UTE has the option of taking 40% stakes in any new power plants built by the private developers.

The law also promised the creation of a wholesale power market to be monitored by the Electricity Market Administration (ADME). The market is not yet functioning as the government continues postponing its launch. Once ADME is operating, large energy consumers (above 500 kWh a month) will be able to choose their supplier. Another aspect of the 1997 law, which has yet to be upheld, is the division of UTE into separate companies for generation, transmission and distribution.

At the end of 1988, to prepare for competition and improve customer service, UTE began a Process to Improve Management (PMG) across the company. This was designed to change the corporate culture by instilling new values dealing with "customer orientation," "increase in profitability," and affirmation of the principles of "quality, membership and responsibility." Centered in the commercial areas and in distribution, as well as in basic support services such as the information technology division, PMG is extending progressively over time to the remaining areas of the utility.

As result of PMG, public perceptions of the utility improved from a level of from 40 percent in December 1991 to 74 percent in December 1994. Over the decade, distinct factors will determine the necessity for promoting new changes:

- a) The stop in the growth of the popularity of UTE, which after reaching 74 percent in December 1994, decreased to 65 percent and 69 percent respectively in December 1995 and 1996 respectively, was caused, among other reasons, by the improvement in service which concomitantly generated a "culture of demand" among its customers

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<sup>30</sup> Based on two papers provided by Luis Oscar Minetti, "Actividades de gerenciamiento de la demanda en UTE," and "Nueva estrategia comercial de UTE: gestión de ventas y gestión de demanda."

- b) The rapid and significant changes nationally and internationally, a new Regulatory Framework in the electricity sector, the imminent admission of natural gas to the energy matrix, and the participation of multinational corporations in the distribution of gas by main line
- c) Thirty percent of total sales constituting the portion “in competition,” where electricity is one alternative among various sources of energy available. As an example, in the last Population and Household Census (1996), the percentage of households that used electric energy to cook food was 10.2 percent, to heat water 61.8 percent, and to heat the home 26.2 percent, respectively, with decreasing pesos, increasing pesos, and constants with respect to the immediate past
- d) The growing importance of electricity in total energy consumption, whose share rose from 8.6 percent in 1970 to 19.6 percent in 1996. This translates into increased use of low cost appliances with significant instantaneous demand requirements and causes a deterioration of the load factor of the electrical system. This also causes loss of profitability, since the tariffs put emphasis on energy and not on potential demand. For example, home heating requires 22 percent of installed capacity but only generates 5 percent of annual revenue.
- e) The opening of electricity markets towards more competitive types, and the challenges that it carries, made distributors all over the world realize that just supplying energy is not enough, that it is necessary to offer quality technical and commercial services and a continued adaptation of its products and services in response to the expectations of the customers.

In commercial policy, the current strategic definition of UTE is to maintain historic rates of sales growth - *which involves dealing with the challenge of competition* - in conjunction with the objective of maximizing the use of installed capacity. The latter requires policies for demand management, which will discourage usage that is not profitable, that is to say, that which requires heavy power demand and has low impact on revenues (low load factor).

As a result, and to deal with the new challenges, the commercial policy was gradually renovated. It began in the 1994-98 period, with the introduction of smart rates (time of use rates). Increase of the load factor was the objective at the time, while for the customer the benefit was limited to a reduction in their electric bill, a change for medium-consumption households. As a unique promotion, a timer (meter) was given to the customers, who could freely choose to continue with this modality.

In December 1999, a total of 9,174 customers had opted for this pricing system, 2,396 of which were residential. The load factor of the interconnected system, which was 56.6% in the year 1994, rose to be 63.8% in 1999; a significant increase, but this does not necessarily imply that this resulted from household changes in usage of the time of use customers.

The development and updating of the rates is the responsibility of the Rate Management Analysis Sector. There are four time-of-use rate groups (Medium Consumers, Large Consumers, General Critical Peak Pricing and Residential Critical Peak Pricing), which are distinguished by the customer categories that relate to each.

The Large Consumers tariff was implemented in 1987 as an optional rate for industrial customers, but, for various reasons, there was no great repercussion until 1991. In the years 1992 and 1993 a series of changes took place that culminated in the fixing of the current price structure, which responds to the modalities of customers' consumption, namely:

- Increase of the Large Consumer Rate for all customers over 200 kW consumption – 11/1/1992
- Creation of a Medium Consumer Rate – 12/1/1992
- Creation of General Critical Peak Pricing Rates and Residential Critical Peak Pricing Rates – 4/1/1993

Customers with this type of contract pay different prices according to the time of day. The Large and Medium Consumer rates are divided into three hours periods in a day, while the other two only distinguish two periods. The basic idea is to have prices during the heavy load hours (peak hours) be greater than prices during the low load hours (off-peak). The commercial action aims to inform customers about the characteristics of these rates and offer them measurements that allow them to reduce their consumption during the peak hours. The customers who can make this change will save money while consuming the same amount of energy. The prices of various levels are calculated such that the resulting reduction of revenues will be offset by a reduction in supply costs.

There are also two seasonal rates (seasonal MC and seasonal LC, created on 11/1/1993), which are advisable for customers who have a higher demand during the summer, which is a lower demand period for the system. Unfortunately, in Uruguay there are customers with this type of demand who still clutter the zone networks (supply systems) that they provide. The legal impossibility of creating zonal rates prevents the progress of this instrument in improving the demand curve.

In the particular case of Uruguay, the reduction of supply costs is owed primarily to the reduction of costs of investment in the networks (supply systems). Indeed, the supply systems have to be measured such that they are capable of providing the maximum instantaneous demand. So, there ends up being a saving of investment costs (in an average period) by expanding the networks (supply system), if the system can take on more energy without increasing the maximum demand.

The data in the following table show that in 1999, 36 percent of energy sold and 21 percent of manufacturing was served on time of use (TOU) or seasonal contracts. These numbers show that the average rate in this category is much lower than the rest; furthermore, each customer can reduce their energy cost by changing their demand curve. The growth observed in customers that opt for these rates was up to 23 percent in 1998, which shows the acceptance of this system.

**Table 5-7**  
**Registration For Rates in 1999, Uruguay**

	Energy (GWh)	(%)	Millions of \$	(%)
General	955	15.68	1,633	22.50
Residential	2736	44.92	3,812	52.53
Public Lighting	182	2.99	253	3.48
Medium Consumers	661	10.86	666	9.18
Large Consumers	1429	23.46	754	10.40
General Critical Peak Pricing	48	.79	66	0.90
Residential Critical Peak Pricing	34	.56	38	0.53
Seasonal Medium Consumers	24	.40	20	0.28
Seasonal Large Consumers	21	.35	14	0.20
<b>Total</b>	<b>6090</b>	<b>100.00</b>	<b>7257</b>	<b>100.00</b>
Seasonal	46	0.75	34	0.47
CPP	2172	35.67	1524	21.01
Total DSM Rates	2218	36.42	1559	21.48

During the last few years, there has been a favorable evolution in the system's load factor. In 1998 and 1999, the value reached its highest point in the series (note that the value in 1989 was affected by the consumption restrictions imposed that year). This sustained evolution cannot be explained by circumstantial factors (such as a winter with relatively high temperatures). The behavior observed can be due in part to an increased use of air conditioning equipment. The sales campaign will highlight this effect on the increase in sales of this type of equipment.

Lastly, it is important to note that the regional demand curves do not necessarily have the same shape as the national one. It is necessary that the actions taken to improve the demand curve have a regional perspective.

**Table 5-8  
System Load Factor in Uruguay**

Year	Generation (GWh)	Max. Load	Load Factor
1985	3745	749	0.57
1986	4098	810	0.58
1987	4446	935	0.54
1988	1754	999	0.54
1989	4439	796	0.64
1990	4712	952	0.56
1991	5065	1057	0.55
1992	5318	1141	0.53
1993	5580	1108	0.57
1994	5789	1167	0.57
1995	6117	1204	0.58
1996	6466	1269	0.58
1997	6835	1266	0.62
1998	7194	1287	0.64
1999	7545	1349	0.64

### **5.6 Time-of-Use Rates and Direct Load Control in Vietnam**

Vietnam has experienced demand growth at the staggering rate of over 20% per year—more than double its GDP growth rate – throughout the 1990s. The government-owned national electric utility, Electricity of Vietnam (EVN), forecasts continuing rapid growth in power demand through 2020.

The capitalization needed to support expected growth in demand for both electricity and other commercial energy sources has placed a tremendous strain on Vietnam’s financial resources. EVN estimates that the power sector will need an investment of \$1.5 billion annually over the next 15 years, split about equally into generation expansion and national power grid expansion and upgrading.

Since 2000, EVN has experienced peak load conditions during the evening hours of 6-10pm when hourly loads are two to three times higher than during off-peak hours. The result has been periodic brownouts, low system load factors and major investment requirements in capacity enhancements to meet demand for only a few hours of the day. The projected annual increases in electricity demand over the next few years, combined with the ongoing efforts to increase grid-based electrification to remote areas, will only exacerbate this situation.

The major contributors to the increase in peak loads and energy consumption are end uses such as motors, process loads, and lighting in large industrial and commercial customers and lighting loads in the residential and small commercial customers. Thus, the Government of Vietnam (GOV) and the World Bank have concluded that it is essential for Demand-Side Management (DSM) and Energy Efficiency (EE) programs to be

developed in order to meet the country's resource requirements and minimize the local financial and global environmental impacts of this growth.

In 1997, EVN, with World Bank assistance, commissioned a DSM potential assessment study for Vietnam. This study identified important opportunities for cost-effective electricity savings in a number of sectors and end-use applications. It recommended a phased approach for implementing DSM which could save as much as 700 MW of capacity and more than 3,550 GWh/yr by the year 2010. Based on this assessment, a Phase I DSM effort, supported by a \$3 million grant from Sweden, undertook capacity building activities at EVN and elsewhere, including development of an DSM business plan, creation of a DSM policy framework. Initial work included capacity building, development of a detailed multi-year DSM program, and implementation and evaluation of key “enabling” activities including load research and pilot project in load management and lighting energy efficiency.

Parallel SIDA-supported efforts at Ministry of Construction and Ministry of Science and Technology developed building codes and efficiency standards for lighting and industrial motors. Most importantly, as a result of these early efforts, GOV and EVN have accepted the importance and role of DSM options as a complement to large-scale supply-side investments.

The Vietnam DSM and Energy Efficiency Project represents Phase II of a 12-year (1998-2010) IDA/GEF-supported DSM and EE program designed to achieve significant and sustainable reductions in energy consumption and peak power demand in Vietnam. In June 2002 an associated IDA/GEF-supported project, the System Efficiency Improvement, Equitization and Renewables (SEIER), was approved. The overall objectives of the SEIER project are to contribute to the Government’s rural poverty alleviation efforts, and to improve the overall efficiency of power system services in the country. In particular the SEIER Project seeks to improve overall system efficiency and reduce investment needs through optimizing the transmission system to reduce transmission losses; and reducing the need for generation capacity increases by effective DSM and energy efficiency program. Taken together, the two projects represented an investment of \$240 million in scaling-up the Vietnamese power sector while improving the efficiency of its operations.

The integrated Phase II effort has two parts – a utility DSM component, to be implemented by EVN, and a commercial energy efficiency component, to be implemented by the Ministry of Industry. Most of the EVN component focuses on load management measures, such as time-of-use (TOU) metering, direct load control (DLC), and general tariff reforms. The TOU metering and DLC projects are the focus of this section.

#### 5.6.1 Expanded Time-of-Use Metering Project

EVN first introduced a time-of-use (TOU) tariff in 1998 and has aggressively supported this with the purchase and installation of TOU meters for all customers with loads over 50 kVA or consumption in excess of 5,000 kWh per month. By the end of 2001, EVN

and its power companies had installed about 5,600 TOU meters in customer premises, and by December 2002, over 20,000 customers had received TOU meters.

This is a mandatory program for larger customers, and early indications are that many customers have responded by shifting loads from peak hours to off-peak periods. With the support of the IDA and GEF funding, EVN will continue encouraging large customers to shift their energy consumption, and would deploy TOU meters for all commercial, service and agricultural (irrigation) customers with transformer capacity over 50 kVA. A key program element is marketing and information campaigns that would accompany the TOU meter installations, so customers could understand the TOU tariff and meter and receive information on load shifting and energy efficiency options they could avoid an increase in their overall electricity bill. There will also be a rigorous Measurement and Evaluation (M&E) effort to quantify the price elasticity of demand and load shifting characteristics of different industrial and commercial sectors.

The total estimated peak load reduction from this program is about 70 MW, sufficient to save \$46 million in new capacity investments.

By the end of 2002, there were only 7,714 remaining eligible customers without TOU meters out of the eligible population of 28,600. Economic growth is expected to increase the number of eligible customers by about 8.5% annually, to 39,635 by the end of 2005, creating a total additional 11,000 new customers eligible for the TOU tariff. In this sub-program EVN will procure and install an additional 6,000 TOU meters among existing and new eligible customers during the period 2003 to 2005. Customer eligibility criteria will be large customers with loads in excess of 50 kVA or consumption in excess of 5,000 kWh per year, and the program will emphasize customer types that are likely to provide peak load reductions in response to TOU tariffs.

Despite the beneficial load shifting effects of these efforts, EVN was initially reluctant to expand these efforts due to some customer resistance to TOU metering. For example, a number of customers have responded by installing stand-by generation units and disconnecting from the grid during peak times to avoid peak pricing. This customer pushback has led to additional efforts to reach out to medium and large customers with energy and bill saving suggestions.

The TOU metering project is expected to cost \$2.3 million, of which \$2.1 million is for meter purchase and installation, \$150,000 is for marketing and promotion, \$30,000 is for administration and logistics and \$120,000 is for technical assistance.

The project will result in substantial economic and financial benefits for Vietnam, in terms of reduced and delayed investment requirements in new power sector capacity, eased infrastructure bottlenecks, decreased building/factory operating costs and corresponding increased productivity and competitiveness, increased commercial activity, decreased dependency on imported and domestic fossil fuels, and more environmentally-sustainable economic development.

### 5.6.2 Pilot Direct Load Control Program

EVN in collaboration with two of its operating subsidiaries (Ho Chi Minh City Power Company and Hanoi Power Company) in introducing a pilot direct load control (DLC) program using a distribution power line carrier (PLC) control system to curtail the demand of about 2,000 customer end-use loads (mostly air conditioning, refrigeration, and water heating). The DLC program targets medium to large commercial customers such as hotels, offices, administrative buildings, food stores, etc. The targeted end-uses will be selected so that there is little or no loss in comfort, convenience, or productivity due to the appliance load control. The load control will be exercised only when the power system is experiencing a significant supply/demand imbalance, and the customers will be guaranteed that the control will be exercised for a maximum of 60 times in a year. The estimated peak load reduction from this program is 3 MW.

The pilot DLC project is projected to cost \$720,000, of which \$510,000 is for equipment purchase and installation, \$60,000 is for marketing and promotion, \$120,000 is for customer incentives, \$10,000 is for administration and logistics and \$20,000 for technical assistance.

The TOU and DLC projects allow EVN to focus on end-uses that coincide with the system peak and represent a good example of how utilities can undertake sustainable DSM activities.

## Chapter 6 - Frequently Asked Questions About Dynamic Pricing

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As it begins to think about introducing dynamic pricing programs to improve the demand-supply balance in its electricity sector, each country faces a number of questions design and implementation questions. Some of them will be unique to its situation while others will apply to many countries.

It is important that each country develop a Pricing Communication Plan that addresses the questions that may one day be asked by the Minister of Energy, the Minister of Environment, the Minister of Finance or the Prime Minister. In this chapter, the most frequently asked questions about pricing are enumerated and discussed. They are grouped into four broad categories. The first one deals with dynamic pricing and market restructuring, the second one identifies options for dynamic pricing, the third one discusses barriers to dynamic pricing and the fourth one reviews approaches for recruiting customers into dynamic pricing.

### **6.1 Dynamic Pricing and Market Restructuring**

#### 6.1.1 What is the basic motivation for dynamic pricing?

Motivation varies across utilities and countries but often includes one or more of the following objectives: (a) manage a capacity shortfall, (b) manage a shortfall in energy supply, (c) improve the financial viability of the utility, (d) lower electric rates, (e) lower total (demand and supply) energy costs and (f) improve customer service. Each of these items can be understood to be a long-term goal as well as a short-term or very short-term goal. In other words, dynamic pricing can be used to deal with and/or prevent system emergencies, which is strictly a short-term application. Or it can offset the need for capacity additions in the future, which is a long-term application.

It is important to state the goals clearly right up front. They will, of course, be country specific and may even change over time for the same country, since they embody a political element in them. For example, one country may say that the goal is to minimize electricity rates while another may say that it is to minimize total (demand and supply) energy resource costs. Putting the objectives first allows the relevant cost-benefit tests to be chosen for screening and prioritizing rate programs. The clear specification of goals also allows for logically deriving the optimal level of DSM investment rather than arbitrarily setting it at some figure like one or two percent of utility revenues.

#### 6.1.2 How can dynamic pricing interact with power sector planning and/or with power sector reform/privatization of distribution utilities?

Dynamic pricing is well suited to power sector planning, since it represents a form of marginal cost pricing. Methods for incorporating marginal cost pricing in utility planning are discussed extensively in Munasinghe-Warford (1982) and Turvey-Anderson (1977), which were commissioned by the World Bank specifically for addressing problems encountered in developing countries. For utilities that are undergoing power sector reform and/or privatization, dynamic pricing is an important milestone in the road to

market-based competition. It can be applied by either vertically integrated or unbundled distribution utilities.

6.1.3 For countries at the very early stages of power sector reform, what are the basic ingredients to pave the road for a sustainable pricing reform program?

The first step is the installation of metering and billing systems for all customers. If customers have never paid for electricity before, this will require a cultural and political adjustment. If they have simply paid a fixed monthly fee, that will also require a cultural and possibly political adjustment, as they transition to a volumetric charge that bills them for the amount of electricity actually consumed rather than an amount that is implicit in their fixed monthly fee. This is referred to as Phase 1 of the five-step pricing reform process described earlier in this report. Once customers have accepted the notion for paying for electricity on the basis of the amount consumed, they have been weaned away from regarding it as an entitlement. The stage would then be set for implementing Phase 2 of the pricing reform process.

6.1.4 For countries where a wholesale market already exists or is about to be created, what are the market arrangements to foster dynamic pricing?

It is often thought that locational marginal pricing (LMP) is required for implementing dynamic pricing. That is not the case. It is not a pre-requisite, as Georgia Power, Duke Power and the Tennessee Valley Authority in the U.S. have demonstrated. However, if LMP exists, then dynamic prices can be allowed to vary by location. Transmission markets are also not a pre-requisite. Nor is it necessary to have either wholesale or retail competition.

Interval metering, however, is a necessity for dynamic pricing such as critical-peak pricing and real-time pricing. If time-of-use pricing is being implemented with a few pricing periods, then standard TOU meters can be used, rather than interval meters. However, such TOU meters cannot be read remotely and do not create savings in operating costs.

Finally, it is necessary that demand response created by dynamic pricing be factored into utility planning and operations. Otherwise, the benefits of dynamic pricing will not be valued properly. This will require that proper metrics be available for valuing the capacity and energy resources that are avoided when customers reduce peak loads and/or shift that load to off-peak periods.

6.1.5 What cost pass-through regulatory arrangements are available to support dynamic pricing actions?

The first type of cost pass-through mechanism that needs to be implemented is the cost of interval metering and associated billing and customer systems. Ideally, this cost should be spread out over all customers. As a second-best option, it can be recovered only through the customers that participate in optional dynamic pricing schemes. However, this will tend to raise the unit costs and may result in a low take rate.

A second arrangement would compensate utilities for lost revenues caused by dynamic pricing. This would involve making modest adjustments in the price of electricity for all customers.

A final issue that needs to be considered is how much of the wholesale cost volatility should be passed onto customers. As discussed earlier in this report, one option is for the distribution utility to pass through the entire hourly spot price to customers. Retailers can then bundle various levels of hedged products around this pass through price and sell them to customers. It is likely that simple rate structures, such as TOU rates and CPP rates, will be preferred over more complex arrangements involving one and two-part RTP rates. A recent study has found that most customers prefer simple two-period or three-period TOU rates to manage the financial risk of electricity supply. This was true across a range of mature deregulated markets in Australia and elsewhere.<sup>31</sup>

## **6.2 Options for Dynamic Pricing**

### **6.2.1 What are the pricing options?**

Options include time-of-use pricing, critical peak pricing and real-time pricing. These are discussed at length in the DSM Primer. Which option is chosen will depend on its ability to contribute cost-effectively to the goals identified in the previous question.

### **6.2.2 Can a two-part tariff system be used to provide a better linkage between wholesale and retail markets?**

This rate design was discussed earlier in Phase 2 of the five-step pricing reform process. It requires establishing a baseline usage level for each customer, based on their usage history. For this baseline usage, the customer is charged the historical price for electricity. In other words, if the customer does not change their baseline usage, their electric bill would be unchanged. If customers change their usage, they would be charged a price equal to the marginal cost of electricity (undifferentiated by time of day). The marginal cost estimates do not vary by time period. Nor do they vary by day. Thus, this rate design cannot respond dynamically to changes in demand-supply conditions. If the objective is to link wholesale and retail markets, dynamic pricing is the preferred method.

### **6.2.3 Is there a way to safeguard the poor from the adverse effect of higher peak prices?**

The best way to protect the poor from the adverse effect of a price increase is to convert their price subsidy into an income subsidy and to then phase out the income subsidy over a five to ten year period. The first step is to estimate the amount of the subsidy they are getting currently with low prices. Let us say the amount is \$50 a month. The second step is to raise the prices to their cost-based value and to provide \$50 a month as an income subsidy. This will leave them no worse off than before. But, to the extent that their demand curve has a slope to it, i.e., that these customers have price-responsive demands, they will cut back on usage. Some of the income subsidy will be used to buy higher

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<sup>31</sup> Energetics, "Electricity pricing structures for customers with interval meters," prepared for the Essential Services Commission of South Australia, March 2003.

valued goods and services, leaving them better off than before. Finally, if the government wants to phase out the income subsidies over time, as the economy improves, it should announce this to the poor customers, so their expectations are well managed. This is the logic behind having Phases 4 and 5 in the tariff reform scheme discussed in this report.

#### 6.2.4 Can dynamic pricing take the place of energy efficiency programs?

No, it is not meant to take their place. Both are valuable resource options that should be considered by utilities and governments. Energy efficiency programs target both base load and peak load reductions and can be a valuable complement to dynamic pricing programs. In addition, it is worth noting that dynamic pricing programs often do not have any effect on overall energy consumption. This result is borne out by the California pricing experiment. If the objective is to reduce energy usage, that cannot be achieved with dynamic pricing programs.

#### 6.2.5 Are load curtailment programs compatible with dynamic pricing programs?

Yes, the two can co-exist, as was discussed in the DSM Primer. Load curtailment programs are often best directed at larger commercial and industrial customers and require sophisticated energy management systems at the customer's end. In a few instances, they can be directed at residential customers as well, by using direct load control of key end-use loads such as central air conditioning. All such programs require the use of financial incentives. Some economists have argued that no incentives should not be paid to customers for reducing load, since that involves a subsidy from non-participants. The participants save money when they lower their usage and that should be enough of an incentive.<sup>32</sup> This criticism does not apply to dynamic pricing programs, which charge a higher price during critical time periods and create an opportunity for customers to save money by lowering peak usage.

#### 6.2.6 Can load profiles be used in place of interval meters to implement dynamic pricing rates?

No. Load profiles by definition are static and do not account for changes in customer loads that would occur in response to dynamic pricing. They can be used to establish revenue neutral rates and are, in fact, indispensable for that task. Every utility should create a load research department whose job should be to estimate load profiles on randomly selected samples of all major customer classes. Such profiles can help in the development of cost-based rates of all kinds, not just dynamic pricing tariffs. However, the profiles cannot substitute for interval meters. The latter are needed to record customer loads in the presence of dynamic pricing and to compute accurate bills. The Canadian province of Ontario tried to institute TOU rates with load profiles for a limited period of time. The effort was not successful. The province has now decided to install "smart" digital meters for all residential and small commercial and business customers, in order to facilitate TOU and possibly CPP pricing.

#### 6.2.7 Should dynamic pricing be established as the default rate for all customers?

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<sup>32</sup> Larry Ruff (2002).

From one point of view, that would be the best outcome. This position has been argued, for example, by Commissioner Art Rosenfeld of the California Energy Commission. Customers who did not like the new default rate would be able to opt-out to a non-time varying rate that incorporates a premium for price volatility. The cost of interval meters and associated billing systems would be collected from all customers and be included in the rate base. However, other groups have argued that this would imposed an unfair burden on customers who cannot shift load. Clearly, this is a key policy issue on which there is no clear political consensus.

Dynamic pricing involves issues of economic efficiency and economic equity. Economic efficiency must look at both sides of the equation: the supply-side savings from load reductions compared to the metering and billing cost of achieving those savings. The economic equity balancing is more complex. It is easy to measure the impacts on different customer groups but difficult to the benefits.<sup>33</sup>

### **6.3 Barriers to Dynamic Pricing**

Several barriers are routinely encountered when implementing dynamic pricing. The first one has to do with utility concerns about reducing sales, which appears to be contrary to the objectives of any business. Another concern is the desire to not deprive customers of energy, since that appears to be contrary to the objectives of electrification. Yet another concern has to do with a regulatory concern about being able to recover the cost of the program, primarily consisting of the cost of electronic meters and supporting billing software, from ratepayers. Solutions to these barriers are available. To resolve the first barrier, the utility rate setting process has to “de-couple” sales and revenues. As sales decline in response to the program, rates have to be raised slightly to recover the lost revenue and make the utility financially whole. The second concern can be addressed that customers are not being deprived of economic well-being, as they would be during a blackout or power rationing scheme such as load shedding. The purpose of dynamic pricing is to give customers a choice between paying for expensive peak period power or shifting their usage to off-peak times. Finally, the last barrier can be overcome if the commissions conclude that dynamic pricing is in everyone’s interest and allow the utility to charge customers for the associated expenses, net of any operational benefits that flow to the utility.

#### **6.3.1 Will dynamic pricing create “needle peaks” outside the peak period?**

This is more likely to occur with traditional load management options such as direct load control than with dynamic pricing options. It can occur with dynamic pricing when it is coupled with enabling technologies such as smart thermostats. Needle peaks are more likely to be created with shorter peak periods than with longer ones. They only pose a problem if the marginal costs in the hours where they occur are higher than those in the peak period.

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<sup>33</sup> Personal correspondence with Rene H. Males, former executive director of the EPRI Electric Utility Rate Design Study, May 3, 2005.

6.3.2 Will dynamic pricing merely create new peaks in place of old peaks, e.g., by shifting day-time peaks into evening peaks?

This is only likely to happen over a period of several years, when customers have purchased equipment such as thermal energy storage in large quantities. For most countries, it is a remote possibility.

6.3.3 On a really hot day, especially on a day that comes after several hot days, will dynamic pricing fail to perform?

Most empirical studies have found no evidence of this phenomenon. A recent experiment in California specifically tested and rejected this hypothesis. Customer responses on the second and third days of a heat wave when critical peak pricing events were called were no different than on the first day.<sup>34</sup>

## **6.4 Customers and Dynamic Pricing**

6.4.1 How can customers be recruited to voluntary dynamic pricing programs?

Customers do not participate in such programs for two primary reasons. First, they are not aware that such programs exist. This barrier can be overcome by active marketing on the part of the utility. Second, they are afraid that such rates will raise their bills. Most customers don't know their load shape and don't know what the new rates would do to their bills. There are three ways in which such fears can be overcome. They can be offered a bill protection product for the first year, which would guarantee that their bill would be no higher than what they would have paid at the standard tariffs. Or they could be placed on a two-part tariff, where the first part is based on their baseline usage during a historical period and the second part is based on time-varying charges. If they preserve their baseline usage, their bill would not change. This method requires the monitoring of customer usage and development of profiles during a test period. Finally, the rates can be designed so that instead of being "revenue neutral" for the typical or average customer, they are revenue neutral for an above average peak user.

6.4.2 What steps can customers take to benefit from dynamic pricing programs?

Customers can take a number of steps to benefit from such rates. The simplest ones are low cost measures that involve turning off "low value" light bulbs and elevators and motors during peak hours. They also yield low savings. The second set of measures involves adjusting the thermostat on the central air conditioning or heating system by a couple of degrees. This will often lower the cooling or heating portion of the bill by upwards of 10 percent. Next, they can fire up their standby generation capacity during peak hours. Some customers can curtail large amounts of load using this approach. Finally, they can install time-flexible technologies such as thermal energy storage system. Others, such as those with large process loads, such as petrochemicals, may install co-generation capacity while those with batch processes, such as cement plants, can consider

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<sup>34</sup> Ahmad Faruqui and Stephen S. George, "Quantifying Customer Response to Dynamic Pricing," *The Electricity Journal*, May 2005.

expanding their off-peak production capacity and reschedule operations from peak to off-peak periods.

#### 6.4.3 Can consumers who live in really hot and dry climates respond to dynamic pricing?

Yes. Customers of Arizona Public Service (APS Company and the Salt River Project (SRP), who live in the arid and hot climate of Phoenix, have demonstrated consistently significant response to the optional TOU rates offered by these two utilities. Both companies have enrolled large numbers of customers on TOU rates on a voluntary basis. APS has enrolled almost 40 percent of its residential customers on TOD rates, primarily through enrolling its new customers. APS estimates that the TOD rate, where the peak price exceeds the standard rate by 45 percent, yields a drop of 0.65 kW in customer loads during peak hours. On a company-wide level, the savings amount to a drop of 6 percent in residential peak demand.<sup>35</sup> SRP has about a hundred thousand customers on TOU rates. It has estimated a load drop of 0.88 kW for customers on its TOU rates, representing a drop of about 12.6 percent in peak load per customer.<sup>36</sup>

#### 6.4.4 How can one estimate the likely magnitude of customer response to dynamic pricing?

There are several options for estimating customer response. The best one is to conduct an experiment with a randomly chosen sample of customers.<sup>37</sup> It would be best to design the sample so that there is a control group of customers who would stay on the standard tariff and various treatment groups of customers on different dynamic tariffs. Both groups of customers should be metered before the introduction of dynamic tariffs so “pre-treatment” data can be collected. The California experiment provides a recent example that is worth studying.<sup>38</sup> It would be useful to review the design of other experiments have been carried out in the U.S. and Europe over the past three decades.<sup>39</sup>

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<sup>35</sup> Randy Gunn, “Estimating Demand Response Market Potential,” prepared for the International Energy Agency Demand Side Management Programme, Task XIII: Demand Response Resources, January 2005.

<sup>36</sup> Loren Kirkeide, “Reducing power capacity requirements using two-period time-of-use rates with ten-hour peak periods,” Master’s thesis, Arizona State University, 1989.

<sup>37</sup> On the general topic of experimentation, see Hey, John D., *Experiments in Economics*, Oxford: Blackwell, 1991 and Shadish, William R., Thomas D. Cook and Donald T. Campbell, *Experimental and Quasi-Experimental Designs for Generalized Causal Inference*, Boston: Houghton Mifflin Company, 2002.

<sup>38</sup> For a discussion of the design of this experiment, see Ahmad Faruqui and Stephen S. George, “Dynamic pricing for the mass market: California experiment,” *Public Utilities Fortnightly*, July 1, 2003.

<sup>39</sup> For a review of North American experimentation involving residential customers, see Ahmad Faruqui and J. Robert Malko, “The Residential Demand for Electricity by Time-of-Use: A Survey of Twelve Experiments with Peak Load Pricing,” *Energy*, 1983. English and French experiments are analyzed in the following papers: Christophe Aubin, Denis Fougere, Emmanuel Husson and Marc Ivaldi, “Real-Time Pricing for Residential Customers: Econometric Analysis of an Experiment,” *Journal of Applied Econometrics*, 1995; Andrew Henley and John Peirson, “Time-of-use electricity pricing: evidence from a British experiment,” *Economics Letters*, 1994. Swiss non-experimental data are analyzed by Massimo Filippini, “Swiss residential demand for electricity by time-of-use,” *Resource and Energy Economics*, 1995 and “Swiss Residential Demand for Electricity by Time-of-Use: An Application of the Almost Ideal Demand System,” *The Energy Journal*, 1995.

If there is no time to conduct an experiment, results can be borrowed from other regions with similar climatic and socio-demographic and economic factors.<sup>40</sup> Alternatively, one could launch a non-experimental pilot program to demonstrate the feasibility of the concept.

#### 6.4.5 How does one estimate the long run response of customers to dynamic pricing?

There is a difference between the short run response of customers to dynamic pricing signals and their potential long run response. In the short run, customers do not make any changes in the capital stock of energy using equipment. Their responses are entirely behavioral in character. However, in the long run, they are likely to invest in equipment that will allow them to shift even more usage out of the expensive peak period. Examples include installing thermal energy storage systems, energy management systems, smart thermostats, automatic load controllers and co-generation capability. For planning purposes, long run responses can be simulated by constructing appropriate energy models. Or they can be estimated by observing customer behavior over a long period of time.

Another factor to keep in mind when estimating long run response is that it also involves actions taken by equipment manufacturers and architects in designing equipment and dwellings that take advantage of the possibilities opened up by dynamic pricing. This response is conditional upon a large fraction of consumers shifting over to the new system, so there is a kind of externality here which provides some justification for sharing out the cost of the new metering among all consumers. However a large part of the cost is clearly incurred on a per consumer basis, so the other issue is the extent to which that cost would rise less than proportionately with the number of consumers shifting.<sup>41</sup>

#### 6.4.6 Is it better to deploy dynamic pricing for larger customers before moving on to smaller customers?

Yes, because the cost of metering is a much smaller portion of their energy bills and because there are fewer customers to recruit into the program. Over the long haul, however, all customers should be brought into the fold of dynamic pricing.

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<sup>40</sup> The following paper attests to the feasibility of making such transfers of elasticities: Douglas Caves, Laurits Christensen and Joseph Herriges, "Consistency of Residential Customer Response in Time-of-Use Electricity Pricing Experiments," *Journal of Econometrics*, 1984.

<sup>41</sup> Personal correspondence with Ralph Turvey, April 16, 2005.

## Chapter 7- Glossary Of Terms

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**Aggregator:** Any entity that assembles a group of retail customers and provides or assists in providing electric power and energy supply services to that group based upon the group's electrical usage characteristics or commercial characteristics (e.g., credit). An Aggregator may also provide other services. An Aggregator can be a Retail Electric Supplier (RES). While many (perhaps most) other aggregators will be alternative RESs, an electric utility can often offer aggregation services outside its service territory.

**Ancillary Services Markets (ASM):** Markets for ancillary transmission services such as regulation and frequency response, energy imbalance, scheduling, spinning reserves, system control, voltage support and black start service that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission system.

**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

**Avoided Cost:** The cost to the utility if it had generated or otherwise purchased the power, and which it is able to avoid by implementing demand-side programs. It establishes a benchmark price for energy services and is used to compare resource alternatives. Avoided cost is the marginal long-term or short-term production cost that could be avoided by an alternative supply-side or demand-side resource. In many states, avoided cost rates have been used as the power purchase price offered to independent suppliers (co-generators).

**Bulk Power Market:** A market where wholesale purchases and sales of electricity are made.

**Bundled:** Prior to restructuring, electric utilities offered their services in a "bundled" form. A single utility provided the generation, transmission and distribution to customers.

**Bundled Utility Service:** All generation, transmission, and distribution services provided by one entity for a single charge. This would include ancillary services and retail services.

**Contract Customer:** A customer that is contestable and has signed a negotiated agreement with the retailer of their choice or who has been placed on a default service contract on the expiration of the franchise tariff.

**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.

**Curtailment Service Providers (CSP):** In restructured power markets, a form of aggregator who offers load curtailment from customers in response to price incentives from either a load serving entity or independent system operator.

**Decoupling:** A technique for setting the rates of a utility so that the earnings a company can achieve are not coupled to the level of sales. In standard utility rate setting, at least for non-fuel costs, if sales go down, earnings go down, and if sales go up, earnings go up. This is a disincentive to DSM. Decoupling allows rates to float up and down with the level of sales, so that earnings are not tied to sales.

**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.

**Direct Load Control (DLC):** Programs that involve utility control of specific customer appliances, such as air conditioners and water heaters, often in response to system reliability considerations.

**Dispatch:** A broadcast signaling the initiation of a control strategy or price adjustment.

**Dynamic price or 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)*

**Economic demand response:** Demand response programs that are undertaken on the basis of economic factors, such as high prices in wholesale markets.

**Emergency demand response:** Demand response programs that are undertaken to meet reliability considerations and avoid blackouts.

**End-Use:** The ultimate benefit that utility service provides, or the use to which the utility service is put. For example, in the residential sector, end-uses include space heating, air conditioning, illumination, cooking, refrigeration, motive power (e.g. fans), localized heating such as waterbed warming or electric blankets, hot-air blowers, water heating, personal computing, printing and entertainment/communications.

**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.

**Free Riders:** Customers who are compensated by a program for taking actions that they would have taken in the absence of the program.

**Franchise Customer:** A customer whose annual consumption is below the minimum threshold set for customers who are contestable, or who have elected to stay with their incumbent utility provider

**Incentive Ratemaking:** Refers to the practice of using a price cap or other form of performance-based ratemaking instead of traditional cost-plus ratemaking, to give the utility an incentive to be efficient by letting it retain a larger share of any savings it creates.

**Independent System Operator (ISO):** An independent management team set up to run transmission systems owned by two or more entities. Under the arrangement, owners retain title to their assets and the ISO runs the systems as a joint operation. The ISO files a single transmission tariff for the region, plans and schedules transmission outages, takes a lead role in transmission system planning, collects transmission charges and makes payments to the actual providers. An independent entity that controls a power grid to coordinate the generation and transmission of electricity and ensure a reliable power supply. In the U.S., ISOs are independent of states' utilities and regulated by the FERC.

**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.

**Integrated Resource Planning (IRP):** A form of resource planning in which demand and supply side resources are jointly used to minimize total resource costs.

**Interruptible Rate:** A special utility rate given to certain industrial customer who agrees to have their service reduced or temporarily stopped as part of an agreement with their electric provider.

**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).

**Least Cost Planning:** Also called Least Cost Integrated Resource Planning, Integrated Resource Planning, Integrated Resource Management (or their acronyms). Any of a number of ways to identify, rank, select and price resources for a utility in such a way that all resources are evaluated on "a level playing field" such that the resources selected are the least cost, most reliable resources for the planning horizon

**Load:** The electric power used by devices connected to an electrical generating system. The amount of electric power required to meet customers' use in a given time period. The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

**Load Building:** Refers to programs that are aimed at increasing the usage of existing electric equipment or the addition of electric equipment. Examples include industrial technologies such as induction heating and melting, direct arc furnaces and infrared drying; cooking for commercial establishments; and heat pumps for residences. Load Building should include programs that promote electric fuel substitution. Load Building effects should be reported as a negative number, shown with a minus sign.

**Load Duration Curve:** A non-chronological, graphical summary of demand levels with corresponding time durations using a curve, which plots demand magnitude (power) on the vertical axis and percent of time that the magnitude occurs on the horizontal axis.

**Load Factor:** The ratio of average load to peak load during a specific period of time, expressed as a percent. The load factor indicates to what degree energy has been consumed compared to maximum demand or the utilization of units relative to total system capability.

**Load Management:** Shifting use of electricity from periods of high demand to periods of lower demand, when the cost of electricity usually is lower.

**Load Profile:** Measurement of a customer's electricity usage over a period of time that shows how much and when a customer uses electricity. Load profiles can be used by REPs and transmission system operators to forecast electricity supply.

**Load Serving Entity (LSE):** In a restructured power market, the entity responsible for serving customer load. It may be a load aggregator or power marketer, (i) serving end users within an ISO control area, and (ii) that has been granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the control area.

**Load Shedding:** The process of deliberately removing (either manually or automatically) pre-selected customer demand from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

**Locational Market Pricing (LMP):** Pricing process that raises all wholesale power prices in a zone to a defined level, based on the cost of the most expensive source of power in that zone at a given time. Also called Locational Based Marginal Pricing.

**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.

**Performance-based Ratemaking:** A form of ratemaking intending to make more explicit the performance requirements on which a utility's profits are based. Usually refers to incentive ratemaking (price caps). Can include incentives to meet or exceed specific performance measures, such as prices relative to those of similar utilities, customer service quality, and the like.

**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.

**Rate Base:** The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash, working capital, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

**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.

**Restructuring:** The reconfiguration of the vertically integrated electric utilities. Restructuring usually refers to separation of the various utility functions -- transmission, distribution, generation, and services -- into individually operated and owned entities and the resulting creation of a competitive market for electricity supply.

**Retail:** Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, also are included in this category.

**Retail Competition:** The concept under which multiple sellers of electric power can sell directly to end-use customers and the process and responsibilities necessary to make it occur.

**Retail Customers:** Customers, including residences and businesses, who themselves use the electricity they purchase; also referred to as end-use customers.

**Retail Electric Provider (REP):** An entity that sells electric energy to retail customers in Texas. A retail electric provider may not own or operate generation assets.

**Retail Market:** A market in which electricity and other energy services are sold directly to the end-use customer.

**Reliability:** The ability to deliver uninterrupted electricity to customers on demand and to withstand sudden disturbances such as short circuits or loss of major system

components. This encompasses the reliability of the generation system and of the transmission and distribution system. Reliability may be evaluated by the frequency, duration and magnitude of any adverse effects on consumer service.

**Reliability-Based Programs:** Programs such as interruptible rates and direct load control that are used to ensure pre-set levels of system reliability.

**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. This is often defined with respect to the average customer whose load shape corresponds to the class load shape. However, for voluntary rates, it may be more appropriate to define it with respect to the segment of customers who are the target market of the program. For dynamic pricing programs, the most appropriate customers are the above average peak users.

**Seasonal rate:** A rate in which the prices varies by season, being higher during the peak season. For summer peaking utilities, rates in the summer season would be higher than those in the winter.

**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. Sometimes this is also called a stepped rate or a non-linear rate.

## Chapter 8 – References

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