Chapter 8.

Electricity tariffs

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This document can only be used in the context of the MIT Course ESD.162/6.695/15.032 “Engineering, Economics and Engineering of the Electric Power Sector” and the Comillas Course “Regulation of the electric power industry” and cannot be distributed without the explicit permission of the authors.
This chapter defines the theoretical objectives that regulation should pursue in electricity tariff design (also called ratemaking) and introduces the reader to the issues surrounding that task. Satisfactory tariff design is essential both to promote optimal short-term system usage and to guide efficient long-term demand response. This is because sound electricity tariffs convey information on responsibility in the incurred supply costs to the actors involved. The design of electricity rates is, then, of major importance both in liberalised and traditionally regulated systems.

The pursuit of greater efficiency has been the main driver of the important regulatory change that has shaken the electric power industry during the last two decades. But a number of questions arise around electricity tariff design. What is meant by efficiency? What are the implications of seeking such a desirable objective? Is efficiency the sole principle that should govern electricity tariffs? Is it even the most important criterion? What others might be taken into consideration? How can tariff design enhance efficiency? Can marginal costs be used as optimal economic signals?

A word of clarification is needed on the meaning of the term “tariffs”. Some costs incurred in the supply of electricity correspond to regulated activities (mostly networks, plus other regulated charges) whose remuneration is determined by the corresponding regulatory authority. This regulatory authority also determines how these costs will be allocated and charged with a regulated tariff that is called the "access tariff". Therefore “tariffs” are regulated charges and they apply both in a traditional or a competitive regulatory situation. Under traditional regulation, also the costs of electricity production and commercialisation are regulated and the regulatory authority determines the corresponding charges to the end consumers, which are included in the comprehensive “integral tariff”. On the other hand, under a competitive regulatory framework, consumers freely choose a supplier and each one pays the agreed price for the energy and the commercialisation service. In this case all consumers and (typically) generators pay the common access tariff (implicit in the integral tariff under traditional regulation) and consumers pay the agreed market price with the chosen supplier. Sometimes, under a competitive regulatory framework, consumers are allowed to opt for a regulated integral tariff called the "default tariff", instead of having to select a supplier. And, in all systems where retail competition exists, a “last resort tariff” must exist to be applied in those emergency situations where a consumer may be left without a supplier. All these options will be covered in this chapter, and completed in the next chapter on electricity retailing.

1 “Tariffs are computed, not decreed”. This quotation from The White Paper on power sector reform, prepared by Ignacio Pérez-Arriaga for the Spanish Government in 2005, warns against tampering with electricity tariffs, a common practice of many governments, unfortunately. The role of governments is to establish a sound regulatory framework so the activities necessary to supply electricity are efficiently performed, but not to interfere in the process of computation of the resulting tariffs.
This chapter is divided into six sections. The introduction is followed by a section on the theoretical fundamentals that should govern tariff design, along with the main theoretical approaches that have been adopted over time. That review of the approaches adopted in the past provides insight into the evolution of tariff design to what are presently regarded to be the most advanced solutions. The third section, which focuses on the determination of the access charge to be paid by all system users, describes the methodologies that can be applied to the cost items defined and relates them to the theoretical fundamentals discussed in the second section. The fourth section addresses integral (or default) tariff design, which includes the access tariff (or use of system charge) plus the cost of the energy consumed. The fifth section reviews a series of miscellaneous issues that, while not pivotal to ratemaking, need to be borne in mind, while the sixth sets out the conclusions.
8.1. INTRODUCTION

As noted, although electricity tariff design is a question of cardinal importance, not all of the factors involved have been studied in suitable depth, as this chapter will show. This is somewhat surprising because all electricity systems need to establish rates for electric power in one way or another. The possible explanations for this situation include the lack of transparency that has been and continues to be customary in many countries and regions, whereby electricity ratemaking can be used as a very valuable political tool.

In any event, before listing the primary objectives that should be taken into consideration by regulators when designing electricity tariffs, a proposal for a full ratemaking procedure would appear to be in order. The notion of what rates or tariffs are appears to be clear, for ratemaking has been going on for many years. The steps that should be taken to define a final tariff structure, the visible result of that procedure, are not always obvious, however.

Tariff design can be divided into three fundamental steps (Rodríguez et al., 2008): i) choice of remuneration methods and levels for each business activity (generation, transmission, distribution, retailing, system operation); ii) definition of the tariff structure applicable to end consumers; and lastly iii) allocation of allowed costs to that structure. When presenting each phase, an attempt should be made to comply with general ratemaking principles, which are discussed in this section.

The first step covers two phases: choice of the remuneration scheme and calculation of the allowed costs. Both depend on the type of business and have been discussed in depth in the preceding chapters. Mention should nonetheless be made of the fact that the term “tariff design” is often erroneously used (even in academic articles) to mean this phase only, ignoring the importance of the other two. This chapter, then, focuses on the other two steps: the establishment of a tariff structure and cost allocation. The starting point for this discussion is the assumption that the regulator, in compliance with relevant ratemaking principles, has established the total recognised costs for each regulated business or has the means to estimate the costs of businesses subject to competition, if necessary.

The second step calls for defining the tariff structure. Its design entails establishing consumer groups or tariff categories, the time intervals or periods subject to billing and the terms under which each category and period are to be billed. The choice of one or the other gives rise to a structure on which all possible customers appear. In addition, the design criteria should, as far as possible, comply with all the regulatory principles laid down in the following section. As discussed below, some of the principles limit or at least establish certain guidelines for tariff structure design.

The last step consists of allocating costs to the tariff structure, i.e., distributing the allowed cost items among each and every term on the structure. Like all other phases, cost allocation must be consistent with fundamental regulatory principles.

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2 Except for the retailing activity, which is intimately related to tariff design and will be presented in the following chapter.
It might be thought that each of the above three steps can be conducted separately. Tariff design is not always a linear process, however. Recognised costs can be calculated more or less separately, but the definition of the tariff structure and the calculation of the amount to be recovered under each term in the structure are closely related, for the cost allocation process itself can raise the need for new categories or terms in the tariff structure.

Conceptually speaking, electricity tariff design must meet two main objectives.

- The first is to raise the money needed to pay for the costs of the activities whose remuneration remains under the regulator’s control. Which activities are incorporated in the tariff depends on the adopted regulation, as explained in section 8.2.4. Generation and retailing are only included in the tariff under cost-of-service traditional regulation, or when the regulator sets a default tariff that allows certain categories of consumers to remain under a regulated “integral” tariff, instead of finding a suitable offer from a retailer. This objective links structure design per se to the first step in the ratemaking procedure: the choice of remuneration schemes and levels for the businesses involved.

- The second objective is to send the right economic signals to each customer to favour the optimal socio-economic use of electricity. Consumer behaviour is logically influenced by the current price and its possible future changes. A customer not paying for electricity on a time-of-use basis fails to perceive the incentive to transfer part of the power used from peak to off-peak times. A customer not suitably charged for peak capacity sees no need to attempt to flatten his load curve. Such tariffs clearly fail to convey the right signals to ensure resource use at close to the social and economic optimum.

As discussed below, a balance between the two objectives may be difficult to reach, however. The revenues associated with an economically optimal signal may differ from the revenues needed to satisfactorily remunerate industry businesses.
8.2. THEORETICAL TARIFF DESIGN FUNDAMENTALS

As noted, electricity ratemaking consists of a series of steps taken with a view to reaching two basic objectives: to raise enough money to cover the allowed costs of the businesses involved and to send consumers the right economic signals.

Suitable decision-making criteria based on regulatory principles and the theoretical approaches presently in place are requisite to each step in tariff design. This section, which aims to describe the principles and approaches that are essential to such design, contains also an in-depth discussion of tariff structures.

8.2.1. Regulatory principles

The three phases into which tariff design has been divided can be presented in very different ways depending on the objectives pursued with regulation. These objectives or principles define the characteristics that ideal or optimal tariff design should meet wherever possible.

Theoretically speaking at least, a general consensus has been reached on the regulatory principles that electricity rates should observe. While these principles provide guidelines for establishing tariffs, they also afford a certain degree of freedom or leave room for more than one interpretation. Thanks to this freedom, a number of design options can be envisaged.

The laws, directives and regulations enacted in each country as the basis for electricity tariff regulation and design almost invariably cite a number of fundamental principles (Green and Rodríguez Pardina, 1999), (Berg and Tschirhart, 1989), (Lévêque, 2003), (Rodríguez et al., 2008), (Reneses et al., 2011), (Batlle, 2011).3

![Figure 8-1. Regulatory principles](image)

- Economic sustainability or revenue sufficiency. This principle is the essential point of departure for tariff design. Any company that conducts a regulated business must be able to finance its businesses as well as any new investment required to be able to continue to operate in the future. This principle is directly related to the first phase of ratemaking, namely the calculation of allowed cost. The adopted tariff design must comply with the provisions of Directive 2003/54/EC, according to which they must be non-discriminatory and cost-reflective.

3 The electricity tariffs in place in European Union countries must comply with the provisions of Directive 2003/54/EC, according to which they must be non-discriminatory and cost-reflective.
ensure recovery of this allowed cost, and payment of the electricity market price, when
the tariff also includes this component.

• Economic efficiency in resource allocation. From the standpoint of economic theory,
efficiency means that goods or services should be consumed by whoever benefits most
from them. Efficiency so defined can be achieved by establishing a price signal (optimal
for both the short and the long term) that will prompt each consumer to use the
amount of the resource that is most efficient for the system as a whole (see Chapter 2
for a more detailed discussion). Economic theory sustains that this objective is reached
by ensuring that prices are close to the marginal costs of providing the service.
Therefore, costs must be distributed to reflect as closely as possible the amount that
each customer costs the system, so that consumers can perceive the “electric”
consequences of their decisions on power use. This efficiency principle affects all the
phases of tariff design: the remuneration scheme should further efficiency; allowed
costs should be efficient (otherwise, consumers will not use resources appropriately);
and the methods used in tariff design, both as regards the tariff structure and the way
prices are established, should further efficient consumer behaviour. In short, efficient
rates send consumers the most appropriate signals and constitute a powerful tool for
efficient energy use (Parmesano, 2007). In practice, this “marginal pricing principle”
can be only implemented as a broad guide, because of the complex nature of the
considered activities: networks with lumpy investments and strong economies of scale,
or electricity markets with significant nonlinear operation costs, for instance.

• Equity or non-discriminatory access to the service and cost allocation. As a rule non-
discrimination is agreed to mean that equal power consumption should be charged
equally, regardless of the nature of the user or the use to which the energy is put.
Equity does not mean, then, that the same costs should be allocated to all grid users
(to make this perfectly clear, this principle is often referred to as the fairness rather
than the equity principle). From the standpoint of the electric power business, this
principle ensures that the rates applied do not provide a given competitor (in this case,
customers) any advantage over any other within the electricity system. Each country
has established more or less restrictive measures regarding the implementation of this
principle, which in some cases has been considered to be compatible with certain types
of price discrimination (Lévêque, 2003), depending on the laxity in the interpretation
of the term equity. One example is low income consumers: is it equitable (fair) for them
to be deprived of electric power, defined as it is to be a basic service, because they are
unable to afford it? Or is it more equitable (fairer) for this group of consumers to pay
lower electricity rates?

• Transparency, complementary to the non-discrimination principle. The aim is to ensure
transparency in the definition of ratemaking methodology, its specific application to
each business and publication of procedures and results. The publication of tariffs and
a clear and understandable description of the method used to establish them is the sole
instrument available to verify whether or not the other principles (sustainability,
equity, efficiency...) are being honoured.

• Tariff additivity, an outcome of the principles of sustainability and transparency. This
means that the end rates should be the result of the sum of all the cost items applicable
to each group of consumers. Rates should be calculated from the bottom up, beginning
Chapter 8. Electricity tariffs

with an analysis of all cost items. In addition, the tariffs from which consumers are allowed to choose must be coherently structured. Hence, the sum paid by all consumers for each item should be equal to the total recognised cost of that item. Further to this principle, the impact of each remuneration item on the tariff can be analysed individually. This is consistent with the principle of economic efficiency and can be used to show consumers how the rates they pay are itemised. Additivity is requisite to objective and transparent tariff design (Apolinário et al., 2006a).

Other criteria that may appear to be obvious but which must also be borne in mind are listed below.

- **Simplicity** of the methods proposed, as far as possible, while attempting not to forfeit other more important principles. The aim is to facilitate comprehension and acceptance.

- **Stability** of the methodology used, so that regulated actors are subject to the lowest regulatory uncertainty possible. Companies must be able to make their forecasts with some certainty. Overly high risk may deter investment, to the detriment of satisfactory electricity system operation.

- **Consistency** with liberalisation and the regulatory framework in place in each country at any given time. Specifically, the degree of industry liberalisation affects the choice of the allocation method and even the tariff structure itself.

In addition to the foregoing, other, higher ranking criteria laid down in each country’s regulations may be applicable. Examples in this regard include the protection of low income consumers, application of uniform rates throughout a given region or a country, or environmental considerations.

One relevant observation is the difficulty (actually, the impossibility) of simultaneously meeting all the above principles, at least in their full dimension. This is sometimes attributable to a lack of know-how, but it is often due to conflicts among the principles themselves. For instance, the principle of efficiency may at times clash with the principle of sufficiency (marginal prices, particularly when dealing with networks, do not provide for full cost recovery), equity (efficient cost allocation need not necessarily be socially equitable) or simplicity (where very complex processes are involved). That notwithstanding, all these principles should be borne in mind to know why certain decisions are made, what aims are pursued and what is to be forfeited to reach them. The ultimate objective is to reach a reasonable balance among all the principles discussed here.

### 8.2.2. Tariff structure design

This section focuses on tariff structure design, viewed in light of the principles described above. It first analyses the meaning of cost drivers and their relationship with the variables that can be billed. The following discussion explains how space and time affect

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4 The efficient allocation of some regulatory costs with no obvious criterion for allocation of cost responsibility (such as stranded generation costs, subsidies to domestic fuels or renewables or some network costs) should be efficiently made by Ramsey pricing (allocation of cost in inverse proportion to price elasticity), which is obviously discriminatory.
electric power consumption. Lastly, it describes the tariff structure, along with the elements that guide its design.

8.2.2.1. Cost drivers

Economic theory uses the cost function as an indispensable element to analyse any process. In the pursuit of optimal tariff design it shows that establishing a single rate for all customers is unsuitable. The tariff structure should reflect system costs and customer behaviour. It should be designed by grouping demand side actors as well as cost elements whose behaviour within the system is assumed to be similar. The tariff structure attempts to reconcile the information available on costs with the variables responsible for those costs, through which they can be recovered. The structure should consequently seek to reflect which system elements or variables generate costs and the degree to which they do so. These elements or variables are called cost drivers because they can be used to explain or estimate the costs incurred. Their definition is of major importance in tariff design and must be studied judiciously to suitably reflect the costs associated with each regulated business (Lévêque, 2003), (Apolinário et al., 2006a).

In the case of electric power, the greater share of system costs is determined by two fundamental variables: a customer’s installed capacity (typically, the peak demand that can be handled by the facility in question) and the energy consumed, at a given connection point and time. On these grounds, a very large number of cost drivers could be defined, based on the capacity available and energy consumed at each connection and during each hour of the year. In actual ratemaking practice (in keeping with the principles of simplicity and transparency), however, a manageable number of factors is defined from which the cost function can be estimated as accurately as possible.

Part of the system cost may be reasonably assumed to be linked to a charge that is a function of the capacity available to the consumer, which reflects the instantaneous capacity desired. This, from the ratemaking standpoint, would entail introducing a capacity charge. An essential factor in this regard is the specification of which capacity parameter is to be used as a cost driver. The alternatives are the peak power consumed (if measurable), the capacity defined in the contract or the installed capacity. The type of capacity chosen depends on the type of meter installed as well as the type of contract concluded with the consumer.

Costs linked to the energy or power consumed by each customer may also be defined, charging users for energy consumed as evaluated during a pre-defined period (from several months to a single hour, if smart meters, also known as interval or time-of-use meters, are installed).

In addition to these main charges, each customer is also billed a fixed amount to cover point of supply-related costs (such as customer management costs), i.e., costs that depend on the number of customers. Lastly, most regulations established a one-off connection charge to cover the costs of providing a new customer with electric power.

Table 8-1 summarises the most common cost drivers and associated costs.

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5 Depending on place and time, the system cost of consuming a given unit of energy may vary widely.
<table>
<thead>
<tr>
<th>Cost driver</th>
<th>Associated costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy</td>
<td>Costs associated with the amount of energy consumed during a given period of time</td>
</tr>
<tr>
<td>Capacity</td>
<td>Costs associated with peak demand or the potential to reach that demand</td>
</tr>
<tr>
<td>Connection</td>
<td>Costs of connecting a consumer to the supply grid</td>
</tr>
<tr>
<td>Consumer</td>
<td>Costs associated with the number of consumers connected to the supply grid</td>
</tr>
</tbody>
</table>

While several of the drivers defined are used in standard practice, certain authors (Parmesano, 2007) propose bundling as many of these charges as possible into the energy or power consumed charge.

**Space- and time-based differentiation**

One factor that needs to be taken into consideration in tariff design is that the cost of supplying electric power depends on when and where it is consumed. The cost of supplying 1 kWh in an urban area at night is obviously not the same as delivering that same kilowatt hour in a rural area during the day. Consequently, customer location and time of day constitute cost drivers.

As far as spatial differentiation is concerned, the grid needed to carry one kWh depends on where it is consumed, as do the associated costs. This variation in cost has primarily to do with the amount invested in the grid, but also depends on the energy lost during transmission and distribution, the congestion, the maintenance, the service quality required and so on. Kilowatt hours (kWh) can therefore be differentiated in terms of the location of the service connection. That differentiation also depends on the grid businesses involved and how they are conducted. A consumer in a rural area, for instance, typically generates high distribution costs. But if that consumer is located within a mostly exporting area –i.e. with excess generation over demand–, the associated transmission costs are very low or even negative.

The cost of supplying one kWh also varies with the time of day, as a distinction must be drawn between peak and off-peak demand. On the one hand, when power is consumed during peak demand, the peak grows, necessitating higher investment in grids and power plants to cover consumption at such times. On the other, during peaks, electric power is produced by plants with higher marginal costs (fuel costs) that are used at peak times only, raising production costs. Furthermore, since grid losses rise quadratically with intensity, the heavier the load on the lines, the greater are the losses per kWh. As in spatial differentiation, time-related costs also depend heavily on grid factors. For instance, a user may consume power in system off-peak times (when generation costs are lower) and still have a negative impact on grid costs if his use concurs with a local peak.

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6 Installed, in contract or peak.
Both space and time differentiation must be applied to cost drivers to establish a tariff structure. This means that a single charge for energy or power consumed cannot be defined; rather, this charge depends on the consumer location and the time of day consumption takes place (Rodríguez et al., 2008). No single fixed charge may be defined either, because of the same reasons.

The tariff structure, in short, is meant to be a simplified version of reality. Highly detailed rate structures reduce unfairness, subsidies, inefficiencies and discrimination. But at the same time, greater detail implies greater complexity in a context in which for the time being that may not be socially acceptable or advisable. An overly complex tariff structure may also involve excessive and unjustified rate calculation and billing costs (including meters and information processing).

The structure should, then, reflect existing complexities, but only to a certain extent. Customer categories should be established, along with the various terms in each category, bearing in mind that reality needs to be simplified. The customer groups defined must be carefully designed and with the smallest possible error (given the consequences of that error in terms of non-compliance with ratemaking principles such as efficiency and discrimination).

Bearing all these considerations in mind, implicitly at least, each country has adopted a tariff structure in keeping with the characteristics of its electric and regulatory systems. Some general traits follow:

- Different tariff categories are established for consumer groups regarded to originate similar costs that can be distinguished from the costs generated by other categories of users. The first consideration here is the voltage connection\textsuperscript{7}. But in addition, further to the most widely used cost drivers, consumers in the same category should have both similar consumption patterns and similar location-related circumstances.

- While arguments have been wielded to prevent overly aggressive differentiation, groupings can be established that send the right location-related signals. At this time, the existence of both nodal prices (see Chapter 6) and of several distributors offering consumers different prices is socially and politically acceptable in a considerable number of countries. This is one type of spatial discrimination. In other countries, by contrast, with a single rate in effect everywhere, any two users having the same connection voltage are grouped in the same tariff category.

- Tariffs may differ depending on the hour of the year. As a rule, hours are grouped by periods\textsuperscript{8} with similar consumption patterns, with all hours in a period charged at the same rate. The aim is to reflect the differences in the economic impact of consuming power (or being able to consume power) in different time periods. Tariff periods group

\textsuperscript{7} The voltage levels that are to define different tariffs must be established. As a rule, not all the voltages existing in the system are taken (for that would run counter to the simplicity principle). Rather, they are grouped in three or four levels.

\textsuperscript{8} The implementation of advanced (hourly, or interval or time-of-use) meters would make it possible to establish hourly differences. No consensus has been reached on their universal application, although the trend towards its generalized deployment is clear.
hours by level of responsibility for the costs incurred. Such clustering consists of two steps: seasonal blocks, if any, are first defined and then the hourly intervals within each season are established. Periods are normally determined in accordance with energy prices or total system demand, even though the most accurate procedure would be to define intervals by the cost of the various activities in each hour (Apolinário et al., 2006b). Generally speaking, prices and demand are very closely related to generation and transmission costs, and perhaps less to distribution costs, where grid saturation patterns at certain voltage levels or in certain areas may differ substantially from the overall system profile. Lastly, the definition of hourly intervals calls for a practical compromise to ensure that each rate interval always covers the same hours: on weekdays, all the hours from 4:00 to 10:00 p.m., for instance, should be regarded to be peak time. Furthermore, the tariff periods defined for any given category must adjust to the characteristics of the meters installed at each type of connection.

8.2.2.2. Tariff structure

Tariff categories and periods as well as cost drivers are used to build the tariff structure. This is a table in which tariff categories are normally shown in the rows and the tariff periods in the columns. Each resulting cell contains the cost assigned to capacity, energy consumed and number of customers. The costs of each business must also be assigned to these three drivers, as explained in greater detail in sections 8.3 and 8.4.

When costs are not defined for all the hourly intervals in a given rate category, several columns are merged into one. A conceptual example of a tariff structure is given in Table 8-2.

9 Electricity energy prices and demand are not necessarily well correlated. For instance, in Costa Rica the highest electricity demand coincides with the cold season, which also happens to be the wettest one, with a high level of hydro production and lowest electricity energy prices. This forces to consider more time periods to account for electricity energy price levels and also demand levels for the allocation of network costs.
Table 8-2. Sample tariff structure

<table>
<thead>
<tr>
<th></th>
<th>Winter</th>
<th></th>
<th></th>
<th>Summer</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Peak</td>
<td>Shoulder</td>
<td>Off-peak</td>
<td>Off-Peak</td>
</tr>
<tr>
<td>LV</td>
<td>P* = 1</td>
<td>€/kW</td>
<td>€/kWh</td>
<td>€/customer</td>
</tr>
<tr>
<td></td>
<td>P = 2</td>
<td>€/kW</td>
<td>€/kWh</td>
<td>€/customer</td>
</tr>
<tr>
<td></td>
<td>P = 3</td>
<td>€/kW</td>
<td>€/kWh</td>
<td>€/customer</td>
</tr>
<tr>
<td>MV</td>
<td>P = 3</td>
<td>€/kW</td>
<td>€/kWh</td>
<td>€/customer</td>
</tr>
<tr>
<td></td>
<td>P = 6</td>
<td>€/kW</td>
<td>€/kWh</td>
<td>€/customer</td>
</tr>
<tr>
<td>HV</td>
<td>P = 6</td>
<td>€/kW</td>
<td>€/kWh</td>
<td>€/customer</td>
</tr>
<tr>
<td>EHV</td>
<td>P = 6</td>
<td>€/kW</td>
<td>€/kWh</td>
<td>€/customer</td>
</tr>
</tbody>
</table>

* P: number of time periods in the considered tariff. This table does not correspond to any existing tariff structure; it is only meant to show how a tariff structure could look like.

8.2.3. Marginal cost-based approaches

The tariff structure with its tariff categories, periods and cost drivers is then used in the third stage of ratemaking: the allocation of the cost items to the cells on the tariff structure. This is a very complex task for which no universally accepted procedure has been found. By way of introduction to the specific analysis of the allocation of each cost item (in sections 8.3 and 8.4), this section describes the possible theoretical approaches that can be adopted. The specific use of these approaches to allocate costs to each business is illustrated below, in the aforementioned sections.

Historically speaking and as far as the authors are aware of, the first theory-backed methodologies to be used in electricity tariff design were based on corporate analytical accounting. For that reason, they are known generically as the accounting approach. These methods were meticulously developed and implemented in most USA states—and are still in use today in some of those states—as well as in some countries with vertically integrated electricity systems. The main objective of the accounting approach is to recover all the cost items posted in companies’ accounts, to which end each item is allocated, ad hoc, to the cells on the tariff structure. While the method constituted a significant step forward in its time\(^\text{10}\), it does not send consumers the most suitable

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\(^{10}\) One of the most prominent advantages is its theoretical simplicity, and the need to have standardised regulatory accounting in place, which is particularly useful from the regulatory standpoint to determine the remuneration for regulated businesses. For background to this approach see the description of the traditional regulation in chapter 3 and, in particular, in Annex A of this book.
economic signals (because the cost distribution criteria are not optimal) and from the standpoint of sound tariff design theory, its use is not recommended.

Since the mid-twentieth century, in some countries progress began to be made in the application of classic economic principles to electricity tariff design. Hence, the use of marginalist theory, and specifically long-term marginal costs, began to be explored as the basis for suitable economic signals in electric power pricing. The earliest studies were conducted in France by Électricité de France (EDF) staff, especially Marcel Boiteux. The idea underlying the application of marginalist theory for this purpose is that the resulting rates are fairer and send economic signals that maximise social welfare. The earliest studies found that the most suitable signal would be provided by long-term marginal cost (LTMC), which is defined as the increase in the network infrastructure and associated operation and maintenance costs attendant upon a sustained rise in demand over time\textsuperscript{11}. Both the operating costs and the costs of adapting the existing facilities, i.e., investment costs, would rise with demand. Most of the proposals put forward along these lines, which focused primarily on generation, can be found in Joskow (1976) and Munasinghe (1981). For applications involving electricity systems, LTMC is often replaced by long-term incremental cost (LTIC). The reason is that finite increments are more appropriate for calculating marginal cost in this industry, where decisions to invest in new facilities are discrete. The main advantage of using marginal cost-based rates is they constitute an attempt at making that each consumer defrays the system costs incurred by his own use. One problem is that marginal rates do not generally recover allowed costs completely (especially for the networks, due to economies of scale), and consequently call for significant adjustments that may ultimately distort the economic signals sent to users. Another problem is that LTMC or LTIC are difficult to estimate and are based on questionable assumptions. That notwithstanding, these approaches are still in place in many countries even today, essentially for grid tariff design, as discussed in section 8.3.

With the advent of restructuring and liberalization of the power sector, electricity is traded in wholesale markets with short-term energy prices. It has been shown in Chapter 2 that the application of short-term marginal costs is the most efficient economic signal for power system operation (Schweppe et al., 1988). The short-term marginal cost (STMC) is defined as the increment in operating system costs resulting from a per unit increment in demand at any given time and network node. In most countries, wholesale electricity market design has evolved toward the use of STMCs (normally hour by hour, but also every half hour or even every 5 minutes) as the optimal economic signal for energy trading. Therefore STMCs for electric energy are readily available without ambiguity in space and time. The primary advantage of using STMCs in operation is that the resulting economic signal optimises consumers’ response to the cost of supplying electric power (Kahn, 1988) as well as the response of generators. Since STMC differ by location, when applied to energy injected and retrieved at the different nodes, they result in some rents that could be used to pay for a fraction of the total network costs. Note the essential difference between LTMC of networks and STMC of energy, as described here: while LTMC refers to network total costs, STMC refers to electric energy costs. Therefore, these two approaches do not only differ in being short or long in time, their

\textsuperscript{11} Long-term marginal costs can, by definition, accommodate space differentiation. In other words, increases in cost depend on where demand rises.
underlying concepts have nothing to do with one another. While LTMC of networks is an attempt to assign responsibility of the increment of the demand at each node in the development of the network, the STMCs of energy look at the earnings that the network could make in the short term by purchasing cheaper electricity in some nodes and delivering it (minus losses) at other nodes at a higher price. Under ideal conditions of continuity in the investments, absence of economies of scale and others (see Chapter 6 for transmission), both approaches would be able to allocate the complete network costs to its users. In practice none of them can, unless they are tweaked somehow. Regarding STMCs, as shown in Chapter 6, their use for grid remuneration in general leads to the recovery of only a small fraction of the total cost, making it unsuitable for tariff design.

The network cost allocation problem has only become relevant in parallel with the process of restructuring and liberalization. Under traditional regulation only consumers had to pay for network costs and almost universally the end user regulated tariffs are uniform (i.e. no geographical differentiation) for the same class of consumers that are connected to the same voltage level. On the contrary, when the transmission activity is unbundled and there is competition at wholesale level, transmission cost allocation matters, as it is now of essence to send sound locational signals to prospective new generation investors and, sometimes, also to large consumers. And in the anticipated future distribution networks, teeming with distributed generation and demand response capabilities, locational signals might be also an advisable regulatory instrument.

Since the strict application of marginal principles is unable to give an adequate response to the network cost allocation problem for the reasons described above, it has to be complemented or replaced by other cost causality or beneficiary pays approaches, as explained in Chapter 6 (for transmission) and also Chapter 5 (for distribution). The starting point in these approaches is that the costs to be paid by the network users should be allocated in accordance with each user’s responsibility (or associated benefit) for each cost item. The possible methods derived from this broad principle have been already developed in Chapters 5 and 6. The main difficulty in applying these approaches lies in practical issues, since they require a detailed understanding of the planning function used by the companies involved in each area of the electricity network business, to be able to accurately allocate costs (Lévêque, 2003).

8.2.4. Access charge and integral rate

As discussed in this and preceding chapters, the regulations in place for each electricity industry business have a direct effect on tariff levels (allowed revenues). But the regulatory factor with greatest impact on the methodology adopted is the degree of industry liberalisation, which affects not only rates, but the choice of the allocation method and the very structure of the tariff structure.

Two broad types of electricity tariffs can be distinguished in any electricity market. In a wholly liberalised market, tariffs need not be designed to take generation and retailing businesses into consideration. Consumers pay the network activities with an access tariff, while purchasing power from the supplier of their choice at a freely established price. In this case, the only regulated price is the access tariff, which covers the costs of all the activities whose cost is determined by the regulator, such as the networks, system operation and different types of subsidies. The design of the access tariff is dealt with in section 8.3.
When the electricity market is not liberalised, the price of electric energy and customer management costs must be included in the price of electricity, conforming to what is known as the integral tariff. In practice, this tariff often co-exists with the access tariff when the electricity market is in the process of liberalisation or even after it has been fully liberalised, if the regulator decides to establish a default tariff, as shown in Chapter 9. The integral tariff is addressed in section 8.4.
8.3. THE ACCESS TARIFF

The access or use of system (UoS) tariff covers the electricity system cost items that must be paid by users inescapably, either separately (if participating on a liberalised market) or as part of the integral rate. These cost items, which are determined by the regulator, include the costs associated with regulated businesses along with any other cost the regulator deems should be paid by all consumers.

This section analyses the methodology for allocating the cost items that form part of the access tariff. These costs can be classified into three distinct categories.

- Costs for using the transmission and distribution networks. These normally account for the larger part of the access charge. No universally accepted methodology for allocating grid costs is in place, and a variety of criteria have been adopted for this end.

- The allowed customer management costs incurred by distributors to attend to the customers connected to their grids.

- Other regulated costs, including the costs inherited from preceding regulatory systems and present costs that are deemed to be attributable to power system agents, regardless of whether or not they are liberalised market actors. Some of the costs most commonly included under this heading are listed below.

  Functioning costs of the System Operator, the Regulatory Commission or Market Operator (this cost might be recovered with some charge applied to market agents).

  Stranded costs. In systems undergoing substantial regulatory change, the regulator may consider that it is fair to compensate those former system agents that might be hurt by the change. These costs must be assumed by all consumers.

  Costs associated with environmental and energy diversity policies. This may include the cost of subsidising renewable energy, local sources of energy and energy efficiency programmes.

  Positive or negative deviations over the previous year’s revenues with respect to allowable revenues. This issue is discussed more fully in item 8.5.1.

  Other costs stemming from industry-specific regulation.

8.3.1. Methodologies for allocating network costs

As noted above, no universally accepted methodology is presently in place to allocate transmission and distribution costs to the tariff schedule. It therefore continues to be an open and much debated issue.

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12 The reader is advised, before studying this section, to review what has been already said about network cost allocation and pricing in Chapters 5 (distribution, in particular sections 5.2.3 –network charges– and also 5.7 –impact of distributed generation–) and 6 (transmission, in particular section 6.5 on transmission cost allocation, as well as section 6.5.1 on the requests of connection to the grid).
In most of this section transmission and distribution costs are considered together, despite the existence of specific proposals for each of these businesses. The reason is that here it will be assumed that the initial task of allocating the cost of the transmission network among countries or regions, and even to specific areas or nodes when this is the case, has been done already following the procedures explained in Chapter 6 (Electricity Transmission). Therefore, the job that is left for this section is to design the most adequate format for this component of the tariff for the network users in a certain area or node, once the total cost of transmission corresponding to that area or node has been predetermined. Consequently, for most intents and purposes of methodology, the transmission grid can be regarded to be simply another voltage level on the distribution grid. In many countries the transmission grid is paid for partly by consumers and partly by generators (ETSO, 2009), for it benefits and is used by both. The only change in allocation methodology required under such circumstances is that the part of the transmission grid cost defrayed by generators must be deducted from the total and only the difference allocated to consumers. Also in distribution networks there is connected generation and in some power systems already in significant amounts. Specific tariff for distributed generation will have to be developed, but this issue is only briefly discussed in this chapter, in section 8.5.5.

The accounting approach

The initial attempts to establish a methodology based on the use of the principles of economic efficiency to set grid rates were made in the framework of the accounting approach. As explained in item 8.2.3, in that approach business accounting was used to allocate cost items to the cells on the tariff schedule. One of the major contributions of this type of design (implemented primarily in the USA) was the development of a procedure for systematising ratemaking. That procedure can be translated into a three-stage cost allocation process. Since some of these steps are necessary in causality principle-based methodologies (item 8.3.1.2), they are described more fully under that item.

The billing variables through which costs are to be recovered are defined in the first step. As discussed below, this question is far from having a single solution, although a number of proposals have been put forward. The earliest approaches to the problem (accounting approach) made provision for the fact that network cost is not entirely a result of the capacity for which it is designed (this issue is dealt with in greater depth in item 8.3.1.2). They consequently proposed allocating all grid costs to the capacity charge, with the exception of the so-called minimum distribution grid, a fictitious grid that interconnects all consumers, but carries no electric power. The cost of this latter grid was to be allocated to the number-of-consumers variable, i.e., to be recovered by means of a fixed charge billed to each consumer.

The second step in this cost allocation approach consists of distributing costs across the rate periods defined. Under the accounting approach, this entails merely dividing the cost allocated to capacity. Nonetheless a large number of complex methods of particular interest arose that are still being used in many of the methodologies applied today. One of those methods, the probability of contributing to the peak (PCP) method, distributes the cost across tariff periods in accordance with the likelihood that the hours in each period will concur with grid peak hours.
Lastly, the third step entails cost allocation (by cost driver and period) to tariff categories. Again, a substantial number of methodologies were developed to solve this problem. Many remain current, the coincident and non-coincident peak demand methods being among the most prominent.

As noted, while these approaches led on occasion to scantly efficient cost allocation based on ad hoc criteria, they constituted the point of departure for tariff design and more specifically for cost causality methods. They will not be further explained here.

**Marginal cost-based approaches**

The application of STMC (so far only implemented at transmission level in some power systems) at every node may result in the collection of some revenues, which could be used to partly cover the total network charges, as shown in Chapter 6. Note that the practical application of this methodology to transmission grids has shown that cost recovery was normally under 20% (Pérez-Arriaga et al., 1995) (Ponce de Leão and Saraiva, 2003). Any “suitably modified” STMC that could recover the network costs completely would distort the STMC message completely. Therefore, even in those systems that have implemented STMC at transmission level, another method for network tariff design must be used. The application of STMCs to distribution networks is even less suitable, since cost recovery may be even lower and the signals sent to users would violate a number of tariff principles, such as equity and stability. Indeed, the STMCs for two very similar users may be totally different because of the existing grid layout. If, for instance, a user is located at the beginning of a feeder line, his STMC may be much smaller than a user located at the end of that same line. This situation may be due to completely arbitrary grid planning or network operation criteria and might change if a new line were to be laid, or a network reconfiguration takes place, making these economic signals very unstable.

For this reason, the application of marginal cost-based principles to grid tariff design will be limited to the use of long-term marginal costs. Item 8.3.1.1 describes the application of this approach to grids in detail.

The other approach most widely applied in grid ratemaking, – which in essence is not that much different–, is based on the cost causality (or beneficiary pays) principle. That approach is addressed in depth in item 8.3.1.2.

**8.3.1.1. Long-term marginal cost-based network rates**

The earliest papers that proposed the use of long-term marginal costs (LTMCs) in grid tariff design were authored by French economists (Boiteux and Stasi, 1964) in the mid-twentieth century. They justified the approach on the grounds that consumers must pay the costs they would generate in a perfectly adapted network, for they are not responsible for grid planning.

While the LTMC approach is conceptually attractive in grid tariff design, its practical application poses several problems. Firstly, LTMC must be properly defined, since its meaning is not obvious in the context of electricity grids. In fact, while a number of methodologies based on this approach have been put forward, no consensus has been reached on how to calculate LTMC. No wonder, since the lumpiness of network
investments and the fact that strong economies of scale exist for network investment costs, make a strict implementation of marginal costing to be impossible. Moreover, the application of such methodologies to actual networks normally calls for very complex planning models to perform the calculations. Lastly, as shown in Chapter 6, the use of LTMC for grid tariffs usually entails the non-recovery of the revenues allowed for the businesses involved, necessitating revenue reconciliation or adjustments to attain such revenues. Depending on their magnitude, these adjustments may significantly distort the signals.

For grids, the LTMCs are normally replaced by long-term incremental costs (LTICs) to mitigate the investment lumpiness problem. LTICs can be calculated with planning models which, defining the existing grid as the baseline, optimise an expansion plan for a given demand-side trend.

The new problem with LTICs is that the results are highly dependent on how close or far is the current network from being “perfectly adapted” (i.e. optimal, for a given demand level). With LTMCs this can be avoided by taking as the reference network the one that is perfectly adapted to the current demand. But this network could be very different from the actual one, and the results may be very questionable.

A review of the most relevant methodologies that have been proposed for calculating LTMC-based grid tariff design are described below, followed by a discussion of possible revenue adjustment procedures.

**LTMC- or LTIC-based methodologies**

The paragraphs that follow summarise the main proposals found in the literature on the use of LTMCs in electricity network rate design.

Williams and Strbac (2001) introduced a methodology used by English and Welsh distributors to establish distribution rates. It is based on the DRM (Distribution Reinforcement Model, also called the Generic Pricing Model or 500MW model), an expansion model whose baseline is the existing grid, on which demand is raised by 500 MW at each voltage level\(^{13}\). Long-term incremental costs can be calculated with this model. Costs are allocated either entirely to capacity (although some consumers are charged for energy used, based on load curves) or an energy use charge is defined for upstream facilities and divided among the tariff categories in accordance with their estimated contribution to peak demand.

Marangon Lima et al. (2002) addressed distribution tariff design in Brazil. Instead of marginal cost, these authors proposed an expansion plan-based mean incremental cost, calculated from an aggregated facilities model. Cost was then divided among consumers in accordance with their contribution to area peak demand and the area’s contribution to upstream peak demand (for which load profiles were used).

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\(^{13}\) The choice of a 500-MW increment is based on the fact that it has a sufficient impact on the grid, without diluting the effect of using the existing grid as a point of departure.
Another LTIC-based proposal for distribution grids was put forward by Ponce de Leão and Saraiva (2003). Here also, calculations were performed with a long-term planning model, here based on operating costs, reliability (power not supplied) and investment.

Li and Tolley (2007) presented an innovative way to calculate marginal or incremental costs. According to these authors, conventional LTMC or LTIC calculation (evaluating the investment needed to cover predicted increases in demand and generation) poses two problems. On the one hand, it is a passive approach, for it makes no attempt to modify growth predictions, and on the other, demand and generation forecasts are subject to a good deal of uncertainty. Consequently, they proposed a methodology that attempts to reflect the cost of anticipating or delaying investment by calculating the number of years of service life left for each facility. It then assumes a variation in demand over that number of years. The difference between the present values of reinforcements with and without the variation in demand is used to calculate the LTIC associated with the facility. This methodology is applicable to both positive (consumer) and negative (distributed generation) variations in demand and the result is applied to the capacity charge only.

Taking a similar tack, Li (2007) developed the same methodology but using analytical expressions to calculate LTMC instead of incremental cost. Li and Matlotse (2008) also applied this methodology to calculate reactive energy tariffs, using the reinforcements required to offset voltage limit violations.

Parmesano (2007) staunchly defended the use of LTMCs. This author proposed the recovery of local distribution grid costs with a fixed charge based on design demand, on the grounds that these facilities are not marginal due to minor changes in the demand. This fixed charge may be a monthly charge, a capacity charge or a surcharge on a first tranche of power consumed, paid by nearly all users. For transmission and high voltage distribution grids, by contrast, the paper proposed using charges that would vary by hourly intervals based on the likelihood with which an increase in demand in each interval would affect grid costs.

The Portuguese tariff design methodology is described in Apolinário et al. (2006) and specifically applied to distribution in Apolinário et al. (2009). Tariffs are based on LTMC, although what is actually calculated is LTIC. These researchers used a formula based on the yearly investments needed to meet an increase in demand at each voltage level. In addition to contract capacity (or peak capacity for metered consumers), the billing variables proposed include the mean capacity during the peak period\(^{14}\). Specifically, the charge for using the transmission grid and the central part (i.e., the part used by many consumers) of the distribution grid are included in this billing variable, because a consumer’s impact on grid cost is proportional to his peak capacity during system peak periods. The cost of distribution grids close to the points of supply, in turn, is recovered by a contract capacity charge, for grid sizing is conditioned by a small number of consumers (on occasion, only one).

\(^{14}\) It is actually a charge equivalent to an energy use charge during the peak period.
Revenue reconciliation

As noted, the use of LTMC- or LTIC-based tariffs does not ensure the total recovery of the allowed costs of network businesses, due primarily to the existence of lumpiness, economies of scale and the difference between the present network and the one that is perfectly adapted to the present demand\(^\text{15}\). For this reason, these rates generally need to be adjusted, a process known as revenue reconciliation.

No satisfactory approach has yet been found to this problem, in particular where reconciliation is of significant magnitude, i.e., when there is a material difference between allowed costs and costs recovered through LTMC. In fact, revenue reconciliation is not even mentioned in a substantial number of proposals. The most elementary adjustments are made by applying coefficients to the rates. Two types of coefficients can be envisaged: multiplier and additive. In the former, the rates obtained are multiplied by the ratio of the allowed costs to the LTMC-based revenues. This maintains the relationship between rates for the various consumer categories and tariff periods. In this case, the LTMCs are used as coefficients to recover total costs (Williams and Strbac, 2001), (Marangon Lima et al., 2002), (Apolinário et al., 2009). Another solution uses additive coefficients, i.e., adding the same amount to all rates, thereby maintaining the absolute difference between categories and periods, keeping consumers from shifting consumption from one period to another as a result of the adjustments (Parmesano, 2007).

Economically speaking, the objective is to minimise the effect of reconciliation on consumer behaviour. In this regard, if the consumers’ utility function were known, reconciliation could be conducted efficiently, further to so-called second best methods. One example of these methods, often proposed for electricity tariff design, is to be found in Ramsey prices (Lévêque, 2003). In this method adjustments are allocated to consumers in inverse proportion to their elasticity to price variations. Non-elastic consumers would pay more. Despite its pursuit of economic efficiency, this methodology has two important drawbacks that make it scantily recommendable in practice. The first is that it is discriminatory, violating the principle of equity, for consumers’ private data and not only the technical and economic characteristics of the power consumed are used in the allocation (two consumers with the same consumption pattern could pay different tariffs depending on the use to which the electricity is put). As a rule, Ramsey prices are detrimental to domestic consumers, who tend to be the least elastic in developed countries\(^\text{16}\). The second drawback is that, from a practical standpoint, reliable data on consumer elasticity cannot be readily obtained. One alternative to Ramsey prices (used in Portugal and Spain) is to define elasticities not on the basis of consumers, but of time intervals. In this approach, peak time consumption is regarded to be least elastic.

In pursuit of an efficient signal, Parmesano (2007) proposed a more qualitative approach, which would involve adjusting the fixed charge or creating a surcharge on the first tranche of power consumed, which is paid by practically all consumers.

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\(^{15}\) Contrary to the STMC approach, no detailed studies have been conducted on what part of grid costs would be recovered under LTMC-based methodology.

\(^{16}\) The opposite is typically the case in some developing countries with protected local industries not exposed to competition and impoverished populations.
Lessons to be learnt from LTMC- or LTIC- based methodologies

By way of conclusion, LTMC- or LTIC-based grid tariff design has been and continues to be researched. At the origin, the rationale for these schemes was to design network tariffs as optimal economic signals under ideal conditions. But LTMPs and LTICs can also be seen as an attempt to search for responsibilities in network investments. This is how the method of Investment Cost Related Pricing (ICRP) was developed in the UK in 1990 and it is still used now. All are nonetheless subject to a number of practical difficulties that have acted as a deterrent to their application to network tariff design.

One of the major problems posed by these approaches is the need to reconcile revenues, a practice that ultimately distorts the signal emitted (and the pursuit of that signal is the justification for using LTMC or LTIC). If the signal obtained is ultimately distorted, calculating rates from marginal costs may in the end be fairly futile.

Another important problem is that LTMCs and LTICs are calculated with optimal expansion tools, which are potentially subject to questionable criteria or manipulation.

Lastly but no less importantly, the approaches proposed focus on high voltage transmission and distribution grids, essentially ignoring low voltage grids. Many proposals call for facility-by-facility calculation (Li and Tolley, 2007), which is not feasible at the low voltage level.

8.3.1.2. Network tariffs based on the cost causality or beneficiary pays principle

Ideally (i.e., no lumpiness, no economies of scale, no economically unjustified reliability constraints and no planning errors), marginal pricing is a theoretically sound approach to assigning responsibility for network investment. However, the difficulties described in the preceding item on the use of LTMCs have given rise to more direct approaches to the application of principles of cost allocation based on cost causality or (equivalently) beneficiary pays. The central idea of the new family of approaches is to consider cost allocation as a by-product of network planning: Network reinforcement has to be justified as the most efficient response to demand growth or –in a market environment– because the cost of the reinforcements is less than the entailed aggregated benefit for all network users. Therefore the planning process must provide enough information to determine how to allocate the costs.

The new family of approaches borrows from the accounting method the emphasis on considering the totality of costs to be allocated from the outset, but now using much more economically efficient allocation criteria. These approaches feature a number of advantages that make them very promising from a practical standpoint, such as set out below.

- The economic signal emitted is efficient if the causes underlying the incurred costs are accurately identified. The causality principle can be likened to a very long-term marginal cost model that includes, in addition to grid reinforcement costs, the cost of replacing all existing infrastructure at the end of its service life.

- These are very robust methodologies because they ensure cost recovery (sufficiency principle). In fact, they start from allowed cost, which is distributed over the various cost drivers, periods and consumer categories in accordance with their responsibility
for costs. If successful in allocating all costs, one advantage of these methodologies over LTMC is that they call for no subsequent revenue reconciliation.

- These are signals that (if the right criteria for identifying the causes underlying cost are used) comply with the non-discrimination principle, for two users responsible for the same grid cost are charged the same.

- Even though the methodology is complex in theory (inasmuch as it entails identifying the causes underlying each cost, which in turn calls for a detailed understanding of the companies’ planning function), reasonable simplifications can be made in practice that lead to simple and transparent tariff design.

The practical application, then, entails designing mechanisms to identify the parties responsible for each cost inherent in grid businesses. The function reflecting the relationship between costs and their causes is (rather appropriately) called the cost causality function. As in the case of the LTMC approach, no single methodology has been universally accepted and a fairly large number of different approaches to the problem have been adopted. As a rule, the necessary know-how must be drawn from grid planning experts to ascertain the reasons for investment and on those grounds to allocate grid costs to each cell (cost drivers, time period, category) on the tariff structure.

In electricity grids, nearly all costs can be regarded to be fixed, for most are the capital costs associated with grid infrastructure and operation and maintenance costs, which may be regarded to be proportional to capital costs.

The causality function for these costs is none other than the decision-making process that leads to investment in grids. The grid planning function must therefore be studied and an analysis conducted of the consumer characteristics underlying investment decisions and the respective weight of each such characteristic in each investment decision. The causality function may be formulated in greater or lesser detail, depending on the degree of differentiation and complexity desired for the final tariff schedule. The implementation of individually personalised rates would naturally be unthinkable for two reasons: firstly, the amount of information needed, its management and tariff handling itself would be practically impossible; and secondly and more importantly, given the characteristics of energy distribution, applying the principle of causality consumer by consumer could lead to highly discriminatory rates. In other words, there is no single or best distribution grid\textsuperscript{17} and there is no way to choose one over another if both have the same costs and requirements. This means that the cost allocated to a specific charge is different in each possible grid and that the cost originated by a given consumer cannot be regarded to be unique. Rather, it depends on the grid chosen.

The tariff schedule must consequently reflect but simplify the causality function obtained. The categories on a tariff schedule must be defined taking these simplifications into consideration, and by grouping variables and consumer groups that give rise to similar costs.

\textsuperscript{17} A number of optimal sites may be defined for substations and transformer stations. Load proximity to or distance from the respective transformer station, for instance, affects its cost to the system. Nonetheless, a consumer should not benefit from or be punished for a design criterion over which he has no say.
As a general rule, four distinct steps are involved in cost causality principle-based grid tariff calculations. The first is the definition of the cost drivers to be used and the allocation to each driver of the part of the cost to be recovered. The second is the establishment of a grid model with which to allocate the cost of each voltage level to the actors responsible for that cost (typically, downstream consumers connected at that level). The third step is to divide the cost associated with each driver among the tariff periods. The fourth and last step is to distribute the cost by driver and period over the tariff categories. On completion of the fourth step, all the cells on the rate schedule will be filled in. These steps are described below, along with some of the most relevant methods proposed for each.

**Step 1. Cost drivers: capacity charge and energy charge**

The first step in calculating grid rates is to decide how to divide the total cost among the possible cost drivers. Some proposals envisage a single capacity charge\(^\text{18}\), although in most cases an energy use charge, or more rarely, a fixed charge, is also implemented. The reason for the single capacity charge is the belief that network investment is solely determined by the peak demand that grids are expected to withstand. This consideration is inaccurate in both transmission and distribution, however, for energy use is also an important variable and at times a determinant for investment levels due to the need to minimise grid losses and to improve reliability. On the other hand, the network charge in many systems is purely volumetric (€/kWh), because of the lack of knowledge about the individual peak loads, given the absence of individual enhanced meters and, frequently, of contracted capacities or any limits to the individual peak demands.

In those cases in which a capacity charge or an energy charge is not the sole charge, most of the approaches to dividing the cost between a capacity and an energy use charge are based on ad hoc criteria. One such criterion, found in several proposals, is to assume that, for a given group of consumers, the cost of the closest grid (typically, the grid for their voltage level) is recovered by the capacity charge, for grid design is regarded to follow local peak demand. The cost of the more distant grid (higher voltage levels), by contrast, is recovered by an energy use charge in the peak period, because this peak is assumed to be responsible for cost in that part of the grid (Williams and Strbac, 2001), (Apolinário et al., 2009). Parmesano (2007) proposed recovering local distribution grid costs with a fixed charge, and the transmission and high voltage distribution grid costs with a capacity charge (or an energy use charge, where smart meters are installed).

Rodríguez et al. (2008) introduced the only method that adopts a detailed network-based quantitative approach to determine the capacity and energy use charges. This proposal consists of evaluating the weight of the contracted capacity and energy consumed in grid development, based on a reference network model (see section 5.5.4.). As we already know, reference network models are tools that deliver the optimal grid design using the parameters that determine grid planning in a given region, such as different consumption patterns and their location, terrain profile, costs of the components needed to meet the

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\(^{18}\) Logically, this capacity charge is designed taking customer location and time of use into consideration as cost drivers. In other words, this charge depends on the tariff period and voltage level and may depend as well on geographic location (urban or rural area).
contract capacity and energy demand requirements (such as cables and transformers), security of supply and service quality criteria. Evaluating the share that should be allocated to capacity and energy use charges is a two-stage process.

- Initially, the reference network model is used to design the optimal grid considering the contracted capacity only, i.e., not the energy demanded at each point of supply. This grid is designed to quality criterion N-1 (or any other, depending on the applicable regulations). The theoretical cost of a grid, if that were the sole design principle, can then be calculated, along with the unit cost per kW of contract capacity that should be allocated to each consumer.

- The optimal grid calculation is subsequently repeated, but considering both contract capacity and the energy demanded by consumers. This grid is also designed to quality criteria (such as the SAIDI and SAIFI\(^{19}\) requisites in place in each area), considering the cost of losses as well. This analysis, especially for medium and high voltage grids, yields a grid whose cost is higher than found in the preceding phase. The difference between the costs of the grids resulting from the two phases is the amount that should be allocated to consumers’ energy use charge.

**Step 2. Definition of a grid model**

As noted earlier, network costs are generally distributed on the grounds of voltage level. Since real life grids, especially distribution grids, are built with a wide variety of voltages, the use of some type of simplified grid is normally used to calculate tariffs. With this model, the cost of each voltage level can be allocated to the actors responsible for the cost in question (typically, downstream consumers connected at that level).

The use of a cascade grid model that envisages the existence of transformers between non-consecutive voltage levels is recommended for this purpose. With this grid layout, inter-voltage level flows and their respective shares can be calculated fairly simply, bearing in mind network losses, power plant delivery at each level and consumption figures. Figure 8-2 shows an example of a grid with the voltage levels proposed by Spain’s National Energy Commission. A simpler example applied to the Libyan system is given in Reneses et al. (2011). Here the possible presence of distributed generation at each voltage level (as shown in Figure 8-2) has been ignored.

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\(^{19}\) System Average Interruption Duration Index and System Average Interruption Frequency Index, respectively.
The following data associated with the grid model are needed to allocate the various voltage level costs to tariff periods and consumer categories:

- energy $E$ and capacity $P$ (be it contract, peak or mean, as discussed below) for each tariff period and category,
- losses for each voltage level and tariff period,
- power plant generation $G$ delivered at each voltage level and in each tariff period,
- flows $w_{ij}$ between the various voltage levels for each tariff period,
- voltage level load curves for each tariff period and
- load profiles for each customer category in each tariff period.

The grid model and associated data are used to distribute the cost of each voltage level among the responsible users, normally consumers connected at that level and the downstream voltage levels (assuming that power flows from higher to lower voltage levels).

Lastly, if different rates are to be instituted in different areas (different rates for each distributor, for instance), the grid model and associated data have to be broken down accordingly.

**Step 3. Cost distribution across tariff periods**

Once the decision has been made as to what portion of the cost is to be recovered under the capacity charge and what portion under the energy use charge, the cost must be distributed across the tariff periods. This is necessary because grid costs depend not only on the energy consumed or peak capacity, but on the time of day when power is consumed.
Standard practice is to distribute energy use costs in proportion to the energy consumed in each tariff period, for the part of network costs recovered with the energy use charge and attributable to each tariff period cannot be calculated a priori. This means that the unit charge is the same in all periods.

The distribution of capacity costs, which is more complex, has been discussed in considerable detail from the earliest accounting approach studies of the problem. A number of very promising and complex methods put forward at the time are still used in many of today’s methodologies. These methods arose out of the need to define hourly intervals and attempt to reflect the existence of times of day which, while inside the system peak periods, are actually not peaks from the standpoint of grid cost distribution (and vice-versa, off-peak hours that are actually peak periods). Three reasons for this can be identified. First, periods are determined beforehand and demand is likely to shift or change sporadically; second, when defining tariff periods, clear and unchanging boundaries must be established (for instance, the weekday peak is defined to occur between 4.00 and 10.00 p.m.), even though this may vary from day to day; third, while grid costs are distributed separately for each voltage level (or even for each facility), the peak for a given voltage level (or area) may not concur with the overall system peak.

One of the most prominent methods is the PCP (probability of contribution to peak) method, that divides the capacity cost for each voltage level by the $H$ hours of highest demand in that level. The capacity cost is divided on the grounds of the share of each tariff period in each level’s peak demand, using the percentage of hours in each tariff period belonging to those $H$ hours (see Figure 8-3).

![Figure 8-3. Capacity cost distributed across tariff periods](image)

This method has been used and continues to be used (implicitly or explicitly) in a fair number of tariff schedule designs (Reneses et al., 2011).

Another simpler approach consists of allocating the entire cost of a facility to its peak demand period (Mutale et al., 2007). Lastly, De-Oliveira-De Jesús et al. (2005) proposed calculating hourly or load interval prices based on optimising social welfare, taking the demand response into consideration.

**Step 4. Cost distribution across tariff categories**

Once costs are allocated to cost drivers and distributed across tariff periods, the last step in their allocation to each cell on the tariff schedule is to divide them into the various consumer categories.
For the energy use charge, the natural and universal method is a pro rata division by the consumption recorded for each category within each tariff period. Hence, the cost of energy during a tariff period is split in proportion to the energy consumed by each tariff category in that period.

For the capacity charge, however, no obvious or generally accepted allocation method is in place. A number of approaches for allocating grid costs to consumers have been put forward in the literature, for this step has drawn more attention than the division across tariff periods. For distribution networks some authors have proposed to use the proxy of network utilization, as it has been also used in transmission (see section 6.4.2.2). These approaches include the MW-Mile method and its variations, Amp-Mile or MVA-Mile (Sotkiewicz and Vignolo, 2007), (Li et al., 2008). In these methods cost allocation entails geographic discrimination, whereby the costs in a given grid area (such as a substation and all downstream facilities) are distributed among downstream consumers in proportion to their consumption and the distance involved (in the example, the distance from the consumer to the substation). Zhong and Lo (2008) proposed using a cross between the MW-Mile and the long-term incremental cost approaches.

In practice, a number of options have been used since the earliest analyses of the problem (accounting approach). The two most prominent are the coincident peak and the non-coincident peak methods. In the coincident peak method cost is distributed by the value of the demand in each category during the peak for the respective tariff period. Under this method, the capacity charge of a group of consumers with a very high demand peak remains unaffected if that peak does not concur with the period peak (Sotkiewicz and Vignolo, 2007). The signals obtained are efficient for high voltage facilities used by all consumers (for they are designed for the system peak) but may not be for all the local grids that are designed to handle the peak capacity in a given area. Mutale et al. (2007) proposed this exercise, but taking into account whether each facility is generation- or demand-governed (i.e., whether the flow is from high to low voltage or vice-versa). Once that is determined, a peak flow charge is applied to each facility so that positive or negative charges can be obtained for demand and distributed generation, depending on the direction of the flow. In the non-coincident peak method, costs are distributed in accordance with the peak for each category throughout the tariff period, regardless of whether or not the peak concurs with the period peak. This method provides better signals for local grids, but not for grids used by many consumers.

Rodríguez et al. (2008) proposed classifying the consumers in a given voltage level by the actual cost they originate by using a reference network model and clustering techniques.

Other alternatives that have been applied include the use of the sum of non-coincident peaks (for each category, each consumer’s peak is added to all the others’; this is unfair, for it fails to take simultaneity factors into account) or of the mean period demand (which fails to emit signals that would encourage peak reduction).

8.3.2. Methodology for allocating customer management costs

The second group of costs that should be allocated to calculate the access charge is the allowed customer management (or commercial) costs incurred by distributors. These are costs directly associated with technical management and the relationship with all
connected customers. Most of these costs are related to metering and billing (where this task is performed by distributors) and customer support.

The solution nearly universally adopted to ensure efficient allocation of customer management costs is to establish a fixed charge per customer. This fixed, typically monthly, charge varies for each tariff category, for the costs associated with different customer categories may vary widely. Indeed, the management costs for a large industrial account may be several orders of magnitude higher than for a domestic consumer. As an alternative to the fixed charge per customer, Parmesano (2007) proposed using a capacity charge or a surcharge on the first tranche of energy paid for by practically all users, so as not to distort the marginal signals that should be received by users.

### 8.3.3. Methodology for allocating other costs

The allocation of the rest of the regulated costs to the access charge is often an open issue. The most advisable general criterion is the causality principle to determine the most economically efficient allocation. That entails analysing the motivations underlying each cost item and, further thereto, to attempting to allocate them to the beneficiaries or actors responsible in accordance with each one’s impact on the total cost. Below are a number of reflections on certain specific costs that are normally included in the access charge.

- **Institutional costs.** Since these costs normally account for a negligible proportion of the total regulated costs, applying a complex allocation criterion is not justified. The traditional solution consists of applying a uniform percentage of each customer’s access charge or an energy use charge.

- **Stranded costs.** Allocation depends on their nature and volume, although in this case the causality principle cannot be applied, for these costs were incurred at some prior time. The solutions adopted usually include a fixed percentage of the bill, a fixed charge or, if the costs are not very high, an energy use surcharge.

- **Costs associated with environmental and energy diversity policies.** The part of these costs defrayed by the electricity industry are normally allocated to an energy use charge, which is usually the clearest cost driver. The target pursued by renewable energy incentives, for instance, is for this type of energy to attain a certain share of the generation mix. Hence, the more energy consumed, the greater the production and associated investment needed in renewable energy and consequently the greater the associated cost. However, distortion of the actual marginal energy cost should be discouraged. And there are sound reasons to charge a significant fraction of the financial support to renewables to other non-electric energy consumptions, like heating or transportation, which also must participate in the efforts to reduce carbon emissions (Batlle, 2011).

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20 While the application of Ramsey prices would be optimal from the standpoint of economic efficiency, the arguments against their application are the practical difficulties estimating the sensitivities and the violation of the equity principle entailed.
8.3.4. Determination of final tariffs

All the steps described in this section lead to the allocation of each cost item to the various cells on the tariff structure matrix. Application of the additivity principle yields the total cost allocated to each cell on the schedule, which is defined by each tariff category (consumer group), tariff period (hourly interval) and cost driver (capacity, energy or number of consumers). The final rates are calculated by simply dividing each of these total costs by the respective cost driver.

Those costs that only depend on the number of consumers must be divided by the expected number of consumers in each category, yielding a charge per consumer and, typically, month. The cost of energy is divided by the volume of energy estimated for each consumer category and period, yielding a charge per kWh. Lastly, the capacity cost is divided by the estimated capacity that has been used to assign costs (contract capacity, coincident peak capacity, non-coincident peak capacity or mean capacity) to calculate a charge per kW.

For categories of consumers with meters able to provide the data needed to bill all these variables, this completes the ratemaking process. Most consumers do not have such meters today, however, and even those that have them may not be subject to such complex tariffs. Consequently, certain cells on the tariff schedule need to be grouped to determine the rates for such consumers, which become simpler.

If a tariff structure is designed with six rate periods, for instance, but domestic consumers only have two, the costs in the cells affected need to be combined. This operation is normally based on load profiles for the category in question, whereby the costs to be recovered in each original cell are calculated, the values found for the combined cells are added and the sum is divided by the sum of the cost drivers.

This type of adjustments to determine the final rates is likewise applicable to determine the integral tariff described in the following section.

There is still one more point to be made regarding the design of the final format of the tariffs to be applied to the end consumers. Not only the amount of network charges to be paid by the end consumer matters, also the format of the charge (€/kWh, €/kW or annual charge) and the process itself of computing the charges matter, as different formats and computation methods result in different economic incentives for the end consumers. Once the amount to be charged to each end consumer is computed as described above, the format of the final charge could be chosen so that any potential distortionary impacts are minimised. This issue was already discussed in section 6.4.3 in the context of transmission charges and it will appear later in this chapter too.
8.4. THE INTEGRAL TARIFF

In most countries, some manner of integral (or comprehensive) tariff is needed that includes all the cost items to be paid by regulated consumers. That would cover the access charge items as well as the energy use items, namely the cost or price (depending on the regulatory framework) of electricity production and any customer management (commercialization) costs. Integral tariffs may be needed to cover either of the following two situations.

- Regulated integral tariffs, in which the cost of electricity production is one of the several regulated costs included in the rate paid by non-eligible consumers (all consumers in non-liberalised markets).

- In most liberalised electricity systems, eligible consumers, at least for some time, are allowed to opt to continue to buy electricity at a regulated tariff termed default tariff), provided by a retailer legally assigned this responsibility (and often related in some way to the distributor to which the consumer is connected). This tariff is discussed in detail in Chapter 9.

An integral tariff often co-exists with the access charge, when the electricity industry is in the process of liberalisation (i.e., in which not all consumers participate in the market yet) or even after full liberalisation (when a default tariff is available as a voluntary protection for some subset of consumers). Irrespective of the circumstances, the regulator must determine the methodology for allocating two further cost items to the access charge to establish the integral tariff, namely generation cost and customer management costs. The present section deals with this issue.

8.4.1. Methodology for allocating generation costs

The first step for including generating costs in the tariff schedule is to quantify the total cost to be distributed among users. The way this sum is determined depends essentially on the regulatory model in place.

- In wholly liberalised markets, it can be obtained directly as the cost of purchasing electricity on that market. Criteria must nonetheless be established to define which price is to be used for this purpose: the spot price, the forward price in any organized power exchange, some measure of the bilateral contract prices or any combination of the three. Some manner of incentive should also be instituted to encourage default retailers to purchase power efficiently.

- Where the market is liberalised but not all consumers have retail access, the price of energy on the wholesale market (spot, organized forward or bilateral contract) may also be used. In this case also, incentives should be established for the efficient purchase of power by retailers acting on behalf of regulated consumers.

- Lastly, where the market is not liberalised, the revenues allowed for generation are determined as the foreseeable total production cost (or allowed cost) for the period in which the tariffs are to be in effect. The following discussion assumes the existence of an organised electricity market. Item 8.4.1.2 focuses on the methodology to be implemented where no such market exists.
The earliest methodologies for allocating allowed generation costs were based on ad hoc criteria, along the lines of the accounting approach. One of the most widely used criteria for dividing costs between the capacity charge and the energy use charge was to allocate the variable costs of generation to energy component of the tariff (€/kWh) and the fixed costs (capital costs and generation-independent operating and maintenance costs) to the capacity component (€/kW). In the specific case of hydroelectric plants, instead of assigning the total cost to capacity, part of the investment was regarded to be earmarked for storing fuel and consequently allocated to energy. The energy use costs were distributed more or less intuitively across tariff periods, based on the volume of demand in each period weighted by the cost of the fuel used. One of the methods used for capacity costs was the BIP (base, intermediate, peak) method, which classifies generating technologies in one of three categories: base (operating all year), intermediate and peak (only operating during the hours of highest yearly demand). The peak technology costs were allocated to the winter peak, the intermediate technologies equally between the winter and summer peaks, and the base costs were distributed equally over the winter and summer peaks and the off-peak period.

The greater availability of information and the enhancement of IT tools has logically allowed the development of more sophisticated and efficient methodologies. More specifically, in the nineteen seventies and eighties, a great deal of progress was made in establishing the price of generation based on the long-term marginal cost approach. Under that approach, marginal cost is calculated as the increase in total generation cost attributable to a sustained increase in demand over time, including both operating costs (essentially fuel and maintenance costs) and the cost of investment in new power plants (Joskow, 1976), (Munasinghe, 1981). Normally, these LTMCs are calculated with a system planning and operation tool able to deliver costs broken down by time and even geographically. LTMCs are allocated to the energy component of the tariff.

The main advantage of the LTMC approach is that it sends consumers a stable long-term signal, encouraging long-term economic efficiency. It has two drawbacks, however. On the one hand, since the short-term signal (real costs at any given time) is lost, consumers do not perceive deviations from the usual pattern of prices and, in particular, exceptional situations (such as drought, high demand or steam plant outages) with very high costs. Their concomitant failure to react to such situations threatens system security of supply and is not economically efficient. And on the other hand, it does not generally ensure recovery of allowed generating costs (depending on the specific rules for remunerating generation, revenues may be higher or lower than allowed), necessitating adjustments that distort the signal.

In any event, the use of LTMCs to set generation tariffs began to wane with electricity industry liberalisation, although some authors continue to propose their implementation, particularly for transition economies (Vikitsert, 1995), (Malik and Zubeidi, 2006).

Industry liberalisation and the appearance of electric power wholesale markets led to the widespread use of short-term marginal costs as the optimal signal for remunerating the

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21 Although the first proposals to address the problem arose around mid-century, they did not begin to gain popularity until several decades later.
generation activity and establishing generation tariffs (Schweppe et al., 1988), (Andersson, 1984). These marginal costs (or spot market prices) are transferred directly to consumers as an energy use charge, whereby the cost is distributed among them in proportion to the energy consumed at any given time. Moreover, these marginal costs can be used as a basis for both geographic (since spot prices can vary from one node to another) and by time of use (since prices are normally set by the hour) differentiation. The main advantage of using STMCs is that this approach sends consumers the most economically efficient signal, for account is taken of the cost of supplying power at any given time (and if the market is nodal or area-based, in any given place). The scheme therefore reflects the situation actually prevailing: demand, hydroelectric reserves, fuel costs, outages and so on. Moreover, in systems with a wholesale market it is the most transparent signal and the simplest to implement.

Some people argue that a drawback to STMCs is their volatility. It is true that the wholesale market price, which represents the real cost of energy at any given time, may vary abruptly and reach very high or low values in certain circumstances. Other people claim that today most users are not prepared to react to real time pricing (RTP). In reality all consumers—with advanced meters on not—are equally exposed to these volatile short-term energy prices and pay them. The only difference is that those with advanced meters have the information about real time prices and may react to them, while consumers with simple meters are subject to the same prices but do not have the possibility of doing anything about it.

Improved information and communication technologies afford the opportunity to conduct large-scale experiments, and a substantial number of articles have attempted to analyse the effect of applying tariffs based on STMCs (see, for instance, Borenstein (2005)). The unrelenting trend is for an increasing number of users to receive some manner of time-of-use signal, in response to the pursuit of economic efficiency and improvements in demand-side management. For low voltage consumers, these signals are usually time-of-use (TOU) rates, which are calculated ex ante with electricity system operating models that estimate the expected STMC values. One factor that should be borne in mind is that while more stable price signals lower the consumer exposure to hourly STMCs, these more stable signals are nonetheless less efficient from the standpoint of system operation. In some countries, regulators require default suppliers to conclude agreements for part of the energy they need to buy for their customers (for further detail, see the chapter on the retail business) to reduce the exposure to the short-term prices, as any load serving entity would do to hedge against uncertain future short-term prices.

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22 See the chapter on Wholesale Electricity Markets for further details.

23 Consumers could, of course, conclude agreements to protect themselves from volatility, while still being responsive to real time prices if the right format of hedging contracts is chosen, see section 9.3.3 in the retail Chapter 9.

24 It is assumed here that, at the end of the year, there is some sort of adjustment in the tariffs for next year so that any deviation between the estimated tariff for those consumers not directly exposed to the short-term prices and the actual prices during the year is accounted for. See section 8.5.1.

25 The adjustments required once the market price is known are addressed in item 8.5.1.
8.4.1.1. Capacity payment

The regulator may wish to ensure a certain reliability level for the power system (in simple terms this requirement may be visualized as a constraint to install a certain minimum quantity of firm generation capacity above the estimated peak demand). Under a market-oriented regulatory framework this reserve margin can be attained by means of some regulatory mechanism that translates this requirement into some sort of capacity remuneration for generation investments. Since such mechanisms vary much from one electricity system to another, their reflection in rates should take the design criteria into consideration, see Chapter 12.

As a general rule, the charge to cover the cost of the adopted capacity instrument is applicable to all consumers, regardless of the supply scheme and in keeping with their responsibility in generation investment. Since the concern is ensuring generation availability in critical periods (peak system demand, typically), the most suitable variable for allocating this cost should be the peak capacity of each consumer that is concurrent with the system peak\(^{26}\). In practice, the billing variables are usually contracted capacity or actual power consumption (kW) during the peak period. This charge should logically be part of the capacity (€/kW) component of the consumers’ tariff.

In approaches that propose using a planning model to calculate LTMCs, the capacity payment is included therein, if the model is designed to accommodate the reserve restriction. For that reason, LTMCs must be divided into an energy use charge and a capacity charge.

8.4.1.2. Revenue reconciliation

This section only applies to power systems under traditional cost-of-service regulation. As noted earlier, where the market is not liberalised, the remuneration of generation is determined as the allowed cost for the period in which the rates are to be in effect. The allowed cost needs not, of course, concur with the revenues accruing from the (short- or long-term) marginal cost rate design and (if applicable) the capacity payment. In such circumstances, the calculated rate must be adjusted by means of a supplementary charge; this is known as revenue reconciliation.

It is important to note that, in power systems under traditional regulation, it is possible to send to consumers the same efficient short-term signals that consumers may receive under competitive market conditions. As we know from Chapters 2 and 7, the spot prices of electricity in perfectly competitive markets coincide with the short-term marginal costs of generation. In the design of integral tariffs both the short-term prices and the short-term marginal costs have to be estimated ex ante, although adjustments may be applied later, see section 8.5.1. And, with advanced metering, in both cases it is also possible to apply real-time pricing. The main difference is that, under market conditions, the market

\(^{26}\) In the presence of large volumes of intermittent generation (wind or solar PV), or with a significant presence of hydro storage, the power system is more stressed when there is scarce wind and sun and there is little water in the reservoirs, even if the demand is not at the annual peak. Short-term market prices above a prescribed threshold or the exhaustion of operating reserves are more reliable indicators of power system stress than the pure demand level.
price is all that generators receive and consumers must pay (except, when it applies, any capacity payment). With cost-of-service regulation the generators must recover all their allowed costs, and this amount may differ from what consumers would pay under marginal cost-based tariffs. As said before, making generators whole under cost-of-service regulation with marginal cost-based tariffs is the role of revenue reconciliation.

This supplementary charge must be allocated in a way that distorts the marginal cost signals as little as possible. To this end, second best methods, such as Ramsey prices, are sometimes implemented, whereby these costs are allocated to consumers in accordance with their elasticity. As noted in section 8.3, however, these methods are difficult to apply in practice and may violate the equity principle. For that reason, multiplier methods (coefficients that maintain tariff proportionality across periods) or additive methods (coefficients that maintain the absolute value of differences) are often used (Apolinário et al., 2006a), (Parmesano, 2007).

As in the case of market-based regulation, the STMCs are wholly allocated to the energy component of the regulated tariff.

8.4.2. Methodology for allocating customer management costs

In addition to generation costs, retailers that purchase power for regulated rate users also incur customer management costs. As indicated in item 8.3.2, this type of costs is nearly universally allocated by means of a fixed charge per consumer. These charges naturally vary depending on the tariff category, for each customer group is responsible for different amounts of management costs.

If the rate designed for a certain category is intended as a default tariff for a small number of consumers only, high customer management costs can be established to encourage consumers to participate in the market.
8.5. MISCELLANEOUS ISSUES

This section briefly reviews a series of subjects that, while not constituting the core of tariff design, have a bearing on final rates.

8.5.1. Tariff adjustment

As the reader will have realised, ratemaking often entails using parameter forecasts for tariff periods, including items such as the energy consumed by each category, peak demand or number of consumers in a given category. As a result and particularly to ensure that all allowed costs or remuneration based on actual energy prices are recovered, tariff adjustment mechanisms must be designed to revise calculations and offset any deviations once the actual values of these parameters can be determined.

Such adjustments may be made in different timeframes, depending on the item to be revised. Most are made yearly, when calculating the rates for the following year. In some cases, however, semi-annual, quarterly or even monthly revisions are made, depending on the regulations in effect. One of the most common adjustments required is the energy cost pass-through charge applied to regulated consumers. Lastly, special adjustments may be implemented in the event of substantial deviations with an impact on costs that is too heavy to be postponed.

8.5.2. Connection charges

Grid connection charges have been already introduced in Chapters 5 (distribution, section 5.2.3) and 6 (transmission, section 6.5.1.1). These are one-off charges for system connection. Two main philosophies are in place with respect to connection charge design: so-called deep cost and shallow cost tariffs.

In deep cost tariffs the new consumer is charged for the cost of his own service connection and of all the upstream grid reinforcements required to supply the contracted capacity. If, for instance, that entails enlarging a substation, reinforcing a line or changing a relay system, those items are included in the connection charge. This solution carries a very strong location signal for new customers, for connection costs may constitute a very high barrier for connecting to a saturated system. If incorrectly designed, however, it may discriminate inordinately among consumers connected at one and the same part of the grid, depending on when they connected. For instance, once the grid has been reinforced (bearing in mind that reinforcement is discrete), a consumer with exactly the same characteristics as the preceding user may connect to the same point without having to pay for the reinforcement already paid for by the latter.

With shallow cost rates, the customer pays the service and grid connection costs only. All other reinforcements are regarded to form part of the grid costs recovered under the access charge. This rate is not discriminatory, although the location signal is not as strong as in the deep cost approach. An alternative even more beneficial for users is the

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27 In California, in the summer of 2000, two retailers-distributors went bankrupt when wholesale market prices rose abruptly and no mechanisms had been established to transfer these rises to end consumers.
super shallow cost-based connection charge, which includes only the equipment up to the connection line, but not the line itself.

Intermediate models are also possible, such as the so-called shallowish charges, which depend on customer size, location, loads in the surrounding area, connection voltage and so on (Williams and Andrews, 2002).

In any event, the connection charge chosen and the access charge must be consistent to ensure that all the costs incurred by the distributor are acknowledged, and acknowledged only once.

8.5.3. Utilization factors

Even without advanced meters, it is possible to distinguish among small and medium size consumers connected at a given voltage level on the basis of their amount of energy consumption or, more precisely, their utilization factor.

The utilization factor UF of a consumer is defined as its total consumed energy divided by its contracted capacity. The maximum possible value of UF is 8760 (or 1.0, if we normalise all the utilization factors by dividing them by 8760), corresponding to consumers whose demands, at every hour of the year, are equal to their contracted capacities.

If the network charges are accurately computed for many real consumers individually over the entire range of values of utilisation factors, it should be possible to fit a curve to these experimental data. Of course, this curve should be verified and adjusted for each situation, but typically it should have the shape that is shown in Figure 8-4. Since an experimental curve cannot be easily used to define tariffs with a simple format, the curve in Figure 8-4 has been approximated by three straight lines: one fits well the network charges for low UF consumers, other for medium UF and a third one for high UF consumers. These straight lines are now used to define three sets of simple tariffs, since they only have two components:

- A capacity component (in €/kW, applied to the contracted capacity or the estimated peak demand of the considered consumer): This is the value of the straight line at its intersection with the vertical axis: the incurred cost even if the energy consumed is zero, just for being connected).

- An energy component (in €/kWh, applied to the consumed energy, which is proportional to the utilization factor).

Note that consumers with a low utilisation factor, who typically consume preferentially at peak time, have a lower capacity charge, while they have a higher energy charge than other consumers with higher values of UF. The opposite applies to consumers with a high utilisation factor. The explanation should be clear: Even though low UF network users concentrate their consumption at peak times, their coincidence factor with peak demand necessarily has to be inferior to that of consumers with UF close to 1.0, since they consume at almost all times. On the other hand, the energy consumed by low UF consumers is, as an average, more expensive than the energy consumed by high UF consumers, which basically corresponds to the average energy price over the entire year.
Figure 8-4. Network cost functions in terms of the value of the utilization factor.

The set of tariffs that have been defined in this way has an interesting property (inferred from inspection of Figure 8-4): If the consumers know their expected utilization factors for next year and they are free to choose whatever of the three tariffs, they will choose the one corresponding to their true UF values, since this is the one that minimises their payments.

Utilization factors are frequently used in practice in the design of tariffs for consumers connected at low and medium voltages. It allows the tariffs to be better adapted to the load profiles of the individual consumers without having to resort to advanced meters.

8.5.4. Reactive power rates

Reactive energy affects energy losses and voltage regulation, two of the keys to satisfactory system operation. Reactive power impacts grid dimensioning. Most reactive power is consumed in users’ facilities. Consumers can and should, then, participate in controlling this power, with a view to maintaining voltage levels and minimising system losses. Signals should consequently be sent to consumers in the form of a specific charge.

When designing reactive power charges, the signal must be adapted to consumer typology. The keys to good reactive charge design are, on the one hand, meter specifications and on the other, consumers’ capacity to correct reactive power. Reactive charges are often not applied to low voltage domestic consumers, in light of their scant ability to vary their behaviour.

For larger scale consumers, however, reactive power meters are usually installed, to measure consumption only or generation and consumption. Some meters also feature time of day recording. Charges are commonly established in terms of the consumption cosine or tangent when electric power is expressed as a phasor, although this parameter oversimplifies the reactive power issue, particularly for large accounts. Charges that penalise reactive power consumption in peak periods and its generation during off-peak periods are often implemented (Apolinário et al., 2009).

Some authors have attempted to develop specific methodologies to design reactive energy tariffs. Foremost among these methods are the adaptation of the MW-Mile approach (Sotkiewicz and Vignolo, 2007), (Li et al., 2008), and the use of long-term incremental costs on the grounds of the reinforcements required due to voltage limits at nodes (Li and Matlose, 2008).
8.5.5. Subsidies

As maintained throughout this chapter, from the standpoint of economic efficiency, good tariff design ensures that the tariffs charged reflect the costs incurred. This induces efficient system use, guarantees long-term viability and investment and avoids cross-subsidies among consumers in different rate categories. Certain communities of users (low income consumers), however, may not be able to pay the system costs they originate. Subsidies may be in order to enable them to access the service. From a social-economic standpoint, these subsidies are justified by the fact that for certain basic needs, electric power is regarded to be a universal right.

Two forms of subsidies are implemented in standard international practice.

- Subsidies integrated in the tariff, which is often progressive, with higher consumption brackets paying a higher price, and designed so that basic needs (lowest bracket) can be covered at a very low price. This practice is generally unadvisable from the standpoint of economic efficiency, since the same electric energy is simultaneously subsidised for some consumers and charged extra for some others.

- Tariff-independent, explicit subsidies, identifying the beneficiary communities and establishing direct payments to cover the cost of their electricity. The main advantage is that they do not distort the economic signals emitted by rates and their primary drawback is the pitfalls involved in identifying the groups involved.

The funds needed to cover the subsidies may be sourced externally (public subsidies) or internally (recovered as a regulated charge in the electricity tariff).

Another type of subsidy that is unavoidable in ratemaking (in the absence of individual hourly metering) is the cross-subsidy among consumers in the same category. These subsidies are inherent in cost distribution based on behavioural similarities among consumers in a given tariff group. Regardless of how refined the rate categories are, consumption patterns will always vary within each one. Consumers with load profiles less coincident with hourly price profiles subsidise consumers whose demand is very aligned with the periods of high prices.

8.5.6. Distributed generation

The conventional generation plants (large thermal, hydroelectric or nuclear plants) are normally connected to the transmission grid, driving energy flows from higher to lower voltage levels to successively feed demand at each level. For a number of years and due to a variety of reasons, a host of different generation technologies have been appearing, which share two features: small size compared to conventional plants and connection to the distribution rather than the transmission grid.

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28 Another aim of this practice is demand-side management to further energy savings.

29 See Chapter 9 for further details in this regard.

30 The reader is advised to review section 5.7 in Chapter 5, for an introduction to this topic.
In some electricity systems and more specifically in certain areas in some systems, distributed generation (DG) is changing the grid planning and operating paradigm, and giving rise to flows that circulate from lower to higher voltage levels. The regulation of such facilities is a highly topical and open issue whose impact on tariff design should also be studied.

At the present moment there is no generally accepted approach to determine network charges for DG and it can be considered an open research topic. As indicated in section 5.7 in Chapter 5 (distribution), the reasonable way to proceed is to analyse the cost impact on each grid of the penetration of DG with a network reference model, until the experiences obtained may allow the development of general-purpose rules.

Another important factor that has been the object of considerable debate is whether DG connection charges should be based on super shallow costs, shallow costs or deep costs. This is a subject for research that will have to be addressed in depth in the years to come, as DG acquires greater importance in electricity systems.

Another open topic in tariff design, already announced in section 5.7, is the treatment to be given to distributed generation at residential level, i.e. distributed generation such as micro-cogenerators or roof-top solar panels, which are connected at the same node in the distribution grid as the residential demand. If separate meters are used for demand and generation, each one could be properly charged with its specific tariff. If a single meter is used jointly for both (this is usually termed "net metering"), a special tariff design could be developed for this new category of network user, which sometimes behaves as a load and other times as a generator. The problem appears when the distribution charge that is applied to the net metered combination of generation and demand is a purely volumetric one (€/kWh) or almost. Why a problem? Because the local generation avoids the payment of network charges to any existing demand and it is therefore being unduly subsidized. Some credit might be given to local generation for reducing network use, but not as much as 100% reduction in the network charges to local demand per kWh of energy produced.

This discussion makes us thing about a fundamental issue in tariff design, but one that the authors have never seen written or presented in public: the format of the tariff matters and, if necessary, it can be made independent from the monetary value of whatever charge an agent must pay. For instance, once the network charge (€) that a generator located at a node n must pay has been determined, it matters whether the amount is charged to the generator as a capacity charge (€/kW), an energy charge (€/kWh) or an annual lump sum. Note that an energy charge at node n would be internalized by the generator in their bids into the market, therefore distorting its competitive market behaviour. And there is no reason to believe that the same €/kWh charge should apply to any other generator connected at n. Similar reasoning applies to a possible capacity charge (€/kW) for all existing and potential future generators connected at n. Certainly a nuclear plant and a peaking unit connected at n should not pay the same €/kW network charge. This leads us to think that there is no good reason

31 Detailed information on connection charges for distributed generation can be found in the European ELEP (http://www.elep.net) and Green-Net (http://www.greennet-europe.org) projects.
to maintain the fiction of nodal network charges that apply to any agent located at a
given location.
8.6. SUMMARY

This chapter addresses tariff design, covering the fundamental theory underlying the approaches presently in place as well as their practical implications. The conclusions drawn are listed below.

- Electricity tariff design is a highly complex task, theoretically and practically speaking, which has not always received the attention it merits.

- The fundamental ratemaking principles to be borne in mind for tariff design are sufficiency (cost recovery), economic efficiency and equity. Since these principles normally clash, tariff design consists of reaching a compromise among them.

- Other principles to be taken into consideration in ratemaking include transparency, additivity, simplicity, stability and consistency with the regulatory framework.

- The tariff design procedure consists of three main steps: 1) choice of the remuneration scheme and level of remuneration for each one of the activities needed for electricity supply (as presented in the preceding chapters); 2) definition of the tariff structure applicable to end consumers; and 3) allocation of the allowed costs to the structure.

- The design of the tariff structure must be based on cost drivers (billing variables) and tariff periods and categories (consumer groups).

- The earliest attempts at cost allocation conformed what is now known as the accounting approach, based on business accounting. Later, in the mid-twentieth century, marginal pricing concepts began to be applied to ratemaking, in pursuit of economic efficiency. This gave rise to tariff designs initially based on long-term marginal costs. The difficulty involved in applying marginal pricing to network costs eventually led to the advent of tariff design more strictly based on the principle of cost causality (which borrowed from both the accounting and the marginal pricing approaches).

- The cost items accounted for in tariff design can be classified into two categories: access charges (to be paid by all grid users, regardless of whether the regulatory framework is traditional or market oriented) and the remaining charges or prices, corresponding to the generation and retail activities, which can be performed either under traditional or market regulation, and complete the access charge to result (under traditional regulation only) in the regulated integral rate.

- The access charge can in turn be divided into grid costs (normally accounting for the major share of this charge), distributors’ management costs and other regulated costs. The integral tariff is topped off with generation (energy purchase) and customer management costs.

- Network cost allocation has been and continues to be the object of a sizeable number of proposals, which in recent years have been narrowing into a fundamental tenet: cost allocation must be based on cost causality. This principle somehow inspired the early attempts using LTMCs and it is also behind the most recent approaches, which try to exploit the fact that network planning is caused by those agents whose increased
demand or generation has required the network to expand. Therefore, at the heart of the planning process must lay the justification for cost allocation.

- Customer management costs (incurred by distributors and in the integral rate) are recovered practically universally by means of a fixed charge that varies from one rate category to another.

- The most efficient methodology to recover energy purchase (generation) costs is based on marginal pricing principles. Short-term marginal costs plus some adjustment elements for revenue reconciliation (under traditional regulation) or spot market prices (when wholesale competitive markets exist) provide the efficient economic signals to be used in the design of integral regulated tariffs or to be used by retailers in their competitive offers to end consumers.
8.7. REFERENCES


Parmesano, H. 2003. Rate design is the No. 1 energy efficiency tool. The Electricity Journal, vol. 20, pp. 18-25


