Regulation: Grids and Environment

6

Even in liberalised energy markets, grids are still natural monopolies, which need to be regulated. Another reason for government intervention into power systems are so-called external effects, which are defined in economics as impacts of one individual's action on another individual without corresponding market transaction. Environmental damages are a blatant case of external effects, and hence, government intervention is necessary to obtain efficient solutions. Therefore, the chapter aims at answering the following key questions:

- Why do simple market-based approaches not work for electricity?
- What are the alternatives to regulation?
- Which emissions stem from the production of electricity?
- What are the main environmental problems related to electricity systems?
- Which instruments are applicable for fighting environmental problems?
- Which instruments are used for limiting climate change?

Section 6.1 addresses the need and the possibilities for regulation of the electricity grid. The environmental challenges of electricity systems and the possible policy responses are then discussed in Sect. 6.2.

Key Learning Objectives
After having gone through this chapter, you will be able to

- Describe different forms of grid regulation and their practical challenges.
- Understand so-called Ramsey-prices.
- Describe emissions caused by electricity generation and the corresponding environmental impacts.

Supplementary Information The online version contains supplementary material available at https://doi.org/10.1007/978-3-030-97770-2_6.

C. Weber et al., *Economics of Power Systems*, Springer Texts in Business and Economics, https://doi.org/10.1007/978-3-030-97770-2_6

- Describe the different phases of life cycle assessment.
- Understand policy instruments to limit climate change and corresponding binding agreements.

6.1 Grid Regulation

The mainstream economic theory claims that competitive markets will deliver outcomes that may not be outperformed systematically by any form of government intervention. This statement has been formalised through the two fundamental theorems of welfare economics, cf. e.g. Varian (2014). Under well-defined conditions, market outcomes are **Pareto efficient**; i.e. it is impossible to improve one individual's situation through government intervention without at least one other individual being made worse-off. Welfare economics does not claim that such market results satisfy any pre-established fairness condition nor that there is a unique Pareto efficient outcome. Yet, mainstream economics argues that it is unnecessary to interfere in market competition and price formation mechanisms to obtain fair welfare distribution based on the second fundamental theorem of welfare economics. Instead, such distributional issues may be handled separately through redistribution measures, preferably lump-sum transfers. These do not interfere with market price formation and hence do not distort the allocative efficiency of market mechanisms, i.e. the incentives for the most efficient use of scarce resources like energy.

For this key result on the efficiency of market-based approaches to hold, a certain number of assumptions have however to be fulfilled (see also Sect. 7.1.1). One assumption is that there are no natural monopolies, or more precisely, no subadditive and irreversible cost structures over the relevant range of outputs. This condition is violated for electricity grids, as will be discussed in more detail in Sect. 6.1.1. The resulting key regulatory recipes are subsequently addressed in Sect. 6.1.2. Section 6.1.3 focuses on the nowadays widely applied so-called performance-based grid regulation. The pricing of network services and the resulting challenges are discussed in Sect. 6.1.4, notably with regard to distributed renewable energies.

6.1.1 Fundamentals of Electricity Market Regulation

Electricity grids are one example of a number of networks that form monopolistic bottlenecks. Other examples for such networks are distribution grids for natural gas and water, telecommunications and railway infrastructure.

A **monopolistic bottleneck** is a **natural monopoly** with irreversible or **sunk costs**. The essential characteristic of a natural monopoly is **subadditive costs**. The following inequality describes subadditive costs:

$$C(q_1 + q_2) < C(q_1) + C(q_2). \tag{6.1}$$

Thereby $C(q)$ is the cost function for the production of the quantity q of a given good. The statement of inequality (6.1) is then that the costs for producing the total quantity $q_1 + q_2$ are lower than the sum of the costs when q_1 and q_2 are produced separately.[1] This has to be true for the whole relevant range of output. The definition of cost subadditivity may be generalised to the case of multiple goods with joint production:

$$C\left(\sum_i q_i\right) < \sum_i C(q_i). \tag{6.2}$$

If costs are subadditive, a single monopolistic company will be more cost-efficient than any number of competing utilities – the sector is subject to a "natural" monopoly. This is the case with electricity grids: providing a network connection to any given number of customers within one region will always come at a lower cost if done through one network rather than through several, partly overlapping networks. In electricity generation, there are by contrast economies of scale only up to a specific size, e.g. for coal plants up to the current upper limit of about 1000 MW nameplate capacity. Beyond that size, there are no subadditive cost structures to be expected. Hence, competition is likely to function for sufficiently large markets like those of most European countries.

Following Baumol et al. (1982) and others, a natural monopoly by itself does not require government regulation. Regulation is only necessary if costs are not only subadditive but also (at least partly) irreversible. Once a cable is buried in the ground, a large part of the cost is "**sunk cost**", not only in the literal sense but also in the economic sense of not being recoverable. Even if the cable would be dug out again and sold on the market, only a small fraction of the initial cost could be recovered. An example of a market with a natural monopoly but without (or only minor) sunk costs is the airlines market. A large carrier will benefit from subadditive costs since it can use a hub-and-spoke network to provide connection services between multiple destinations. Nevertheless, the market is "contestable"; i.e. new entrants may try to break monopolies and oligopolies since they have only limited irreversible cost. If their business model turns out to be unprofitable, they may still get back essential parts of their upfront investment into aeroplanes by reselling them on a relatively liquid secondary market.

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[1] Note that economies of scale, defined through: $C(\lambda \cdot q) < \lambda \cdot C(q)$ for $\lambda > 1$, are a sufficient condition for subadditive costs, but not a necessary one over the whole output range. Similarly, marginal costs below average costs over the entire output range are another sufficient but not necessary condition for subadditive costs.

In the presence of a monopolistic bottleneck, governments may still choose among different regulatory alternatives (cf. Viscusi et al. 2005): laissez-faire, franchise bidding and state ownership are basic choices, yet they are hardly applied so far to the electricity sector, given that they are generally believed to induce either excessive monopoly rents, contractual problems or low efficiency, or several of these problems. Therefore, the focus in the following is rather on the regulatory approaches in place in Europe and other parts of the world with competitive electricity markets.

The key elements of the regulation in place are:

- Non-discriminatory access to the monopolistic bottleneck, i.e. the electricity grid,
- Unbundling between the monopolistic bottleneck and the competitive parts of the sector, notably generation and retailing,
- Price regulation of the monopolistic bottleneck.

These issues are discussed in the next section.

6.1.2 Non-discriminatory Grid Access, Unbundling and Price Regulation

Subsequently, we start by reviewing the key issues related to non-discriminatory grid access and unbundling in Sects. 6.1.2.1 and 6.1.2.2. Then we discuss the basic alternatives of cost-based and incentive-based price regulation for the monopolistic bottleneck in Sect. 6.1.2.3. This has to be complemented by discussing further regulatory challenges, like quality regulation in Sect. 6.1.3. The question of grid tariff structures may be addressed directly by regulation, but may also be left at least partly to the discretion of grid operators. It is therefore left to Sect. 6.1.4.

6.1.2.1 Non-discriminatory Grid Access

As discussed above, the electricity grid is a monopolistic bottleneck where competition does not work. In the past, economists considered the vertically integrated electricity sector to be a natural monopoly as a whole. Yet, since the 1970s, first economists and then practitioners started to distinguish between the grid as a monopolistic bottleneck and the remaining segments of the industry such as generation, trading and retail services (cf. Joskow 2007). Those do not exhibit subadditive cost structures, and thus, competition is possible in these fields.

Yet, electricity generators need the electricity grid to deliver their product to their customers. Hence, competition is only possible in the field of generation, if access to the grid is possible for all competitors – and the same holds for trading and retail services. Non-discriminatory access to the monopolistic bottleneck is thus a fundamental prerequisite for functioning electricity markets. This has to be stipulated by law (e.g. the German energy act EnWG) and is to be enforced by a regulatory authority (such as the Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (BNetzA) in Germany). This regulator will ensure non-discriminatory pricing by grid companies and also the absence of non-price discrimination measures (e.g. restrictions in grid access). In European markets, a key element for operationalising non-discriminatory grid access are the so-called balancing groups. These virtual entities allow grid users (energy companies, larger industrial facilities, etc.) to bundle their generation and sales activities within one grid area. The grid operator then asks the grid users to provide schedules for infeed and offtake within its grid area so that it can manage the grid accordingly (see Sect. 8.4).

6.1.2.2 Variants of Unbundling

Besides the absence of privileged grid access, grid operators should also not be able to provide other types of advantages to some other (related) player exposed to competition. To prevent such abuse of a monopoly position, a separation between grid and competitive businesses is necessary. This separation imposed by regulation is commonly labelled "unbundling" and in practice, regulators impose different forms of **unbundling**:

Accounting unbundling obliges companies active in both the grid and the competitive part of the sector to keep separate accounts for these activities and, consequently, to have separate balance sheets. This is a minimum requirement for appropriate price regulation.

Informational unbundling includes the requirement that information obtained by a grid operator is not used by the competitive parts of the same company. Otherwise, the company may obtain a competitive advantage compared to its competitors, e.g. through more detailed information about customers (e.g. load profiles). Informational unbundling implies that both business processes and IT systems must be separated between the grid and the competitive business segments.

Functional unbundling (**Management unbundling**) requires that managers in the grid business may not be involved in competitive business segments and vice versa. This prevents information sharing and strategic decision-making in view of overarching company interests.

Legal unbundling is achieved by making any grid operator a separate legal entity (company). As a separate entity, the grid operator has an obligation to keep separate accounts and also informational and functional unbundling are more easily established and monitored.

Ownership unbundling requires that grid businesses and competitive businesses like generation, trading and retail (supply) have different owners. With different owners, all incentives for privileging a competitor should vanish.

The European regulation has gradually increased the requirements for unbundling in the electricity and gas sector. In the first electricity market directive 96/92/EC, only accounting separation between generation, transmission and distribution was required. The so-called acceleration directive 2003/54/EC then required informational, functional and legal unbundling for transmission and distribution grid operators, allowing exemptions to legal unbundling for small distribution grids. The political and regulatory debate around the third internal energy market package (notably directive 2009/72/EC) focused on whether ownership unbundling should be enforced for transmission system operators (TSOs). As a result of a compromise, the European Commission did not impose full ownership unbundling throughout Europe. Instead, directive 2009/72/EC provides two alternative forms of unbundling, labelled Independent System Operator (ISO) and Independent Transmission Operator (ITO), which allow integrated companies like EDF, E.ON or RWE, to hold shares in a transmission system operator, yet with very limited possibilities to influence managerial decisions in the TSOs, which became own legal entities. In practice, many formerly vertically integrated utilities like E. ON and Vattenfall (in Germany) have sold off their transmission assets in the years around 2010.

An issue that has not received comparable attention is whether the distribution grid should be fully unbundled from the retail business. Both the presumed larger market power of generation companies compared to retail companies (also called suppliers) and the lower transaction costs (relative to the company size) may be invoked to justify the focus on transmission unbundling. Yet, with the advent of distributed generation and smart grids, the neutrality of distribution grid operators may become more important. On the other side, coordination between generation, grid and consumption at a decentralised level becomes more important (cf. e.g. Friedrichsen 2015). These trade-offs require further investigation in view of a grid regulation that enables the transition to a sustainable low-carbon energy system (see also Sect. 12.3).

The challenge of regulation at a European scale is further complicated by the broad variety of existing company structures. For example in France, one major distribution grid operator (Enedis, subsidiary of EDF) serves more than 95% of all customers. In Germany, by contrast, there are more than 800 different distribution grid companies of very unequal size.

6.1.2.3 Price Regulation: Cost-of-Service Versus Incentive Regulation

The absence of a well-functioning market for grid services leads to the need to supervise or fix the rates charged by network operators to their customers. The large variety of proposed regulation schemes may be broadly classified into two categories:

- **Cost-of-service regulation and**
- **Incentive regulation**, also called **performance-based regulation**.

These categories may be further subdivided, as shown in Fig. 6.1.

As indicated in Fig. 6.1, the price regulation should be complemented by a (direct or indirect) quality regulation. These and further aspects relevant for practical implementation will be analysed after discussing the basic concepts in the subsequent sections.

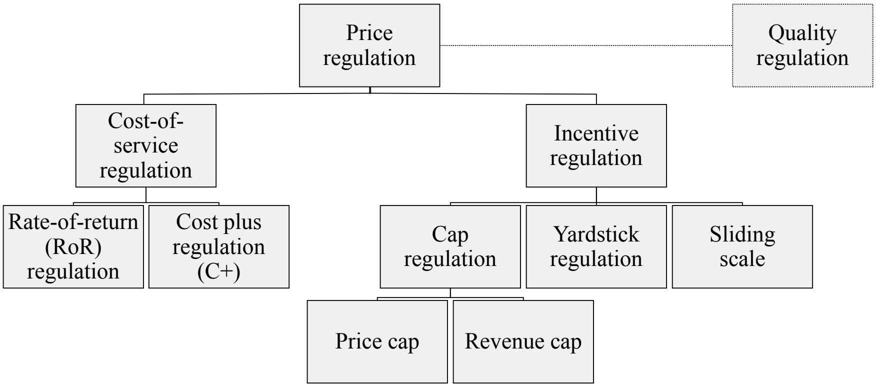

Fig. 6.1 Types of price regulations

Cost-of-Service Regulation

In a cost-of-service regulation, the cost incurred by the provider for delivering the service is taken as the basis for the price regulation by the regulator. Two variants may be distinguished:

Cost-plus regulation, in its simplest form, determines the allowable revenues R_t^{C+} based on the sum of (expected) operational expenditure O_t and capital expenditure based on depreciation C_t^{capex}. On top of this sum, a profit margin a is conceded:

$$R_t^{C+} = \left(O_t + C_t^{\text{capex}}\right) \cdot (1 + a). \tag{6.3}$$

The cost-plus approach was rather popular in Europe before liberalisation but has been mostly replaced by incentive regulation schemes. Operational expenditure includes all recurring expenses, e.g. for staff, raw materials, operation inputs such as energy or insurances and maintenance. It is frequently abbreviated as OPEX, and correspondingly, for capital expenditure the term of CAPEX has been coined. These include the expenses for machinery, equipment like poles and lines, buildings and computer systems. Regulation thereby usually does not consider the cash flows but the annual depreciation. The sum of both is then labelled TOTEX. The cost of capital (interest payment for debt and return on equity) is usually implicitly considered through the choice of the profit margin.

Rate of return regulation has been traditionally employed in the USA. Thereby, the focus is more on the recovery of the capital cost. With a pre-specified rate of return r on the capital employed K_t, the allowable revenues are computed as:

$$R_t^{\text{RoR}} = O_t + C_t^{\text{capex}} + r \cdot K_t. \tag{6.4}$$

Both regulation schemes do not provide an incentive to reduce costs since increases in costs can be passed through to the customers. Even worse, there are incentives for the grid operators to inflate their capital base in the case of a rate of return regulation with a guaranteed return exceeding the actual cost of capital of the operator. This effect has been first described in detail by Averch and Johnson (1962). For the cost-plus regulation, a similar result holds: increases in operational expenses directly increase the operator's profit. Excessive use of capital and correspondingly higher depreciations are also advantageous for the operator in the chosen formulation if the marginal costs of capital are smaller than the profit margin multiplied by the depreciation rate.

Therefore, cost-of-service regulations will only provide welfare-optimal results if the regulator has perfect knowledge both of the actual cost and the cost reduction possibilities of the grid operator. Then she will discard any expenditure on capital and operational goods that are not "used and useful". In reality, information asymmetry prevails and the grid operators have more knowledge than the regulator. By imperfectly applying the "used and useful" criterion, the regulator will aim to limit the operator's profits, yet still no incentives for dynamic efficiency improvements are provided.

Incentive or Performance-Based Regulation

Given the limitations of cost-of-service regulation, economic theory and regulatory practice have come up in the 1980s with the concept of incentive regulation. Littlechild (1983) proposed price cap regulation for the to be privatised British Telecommunications (BT), but the concept was soon after also applied to electricity and gas infrastructures and other sectors.

Price cap regulation in its basic form may be described by the formula:

$$p_t = p_0 \cdot (1 + \mathrm{RPI}_t - (t - t_0) \cdot X). \tag{6.5}$$

Accordingly, the maximum price p_t in year t is determined based on a starting price p_0 in year t_0 adjusted for the inflation through the retail price index RPI_t (measured relative to t_0) and an expected annual productivity gain, labelled X in the original literature. The scheme is therefore also known as RPI-X-regulation.

The starting price p_0 is usually determined based on cost information, whereas expectations regarding inflation and productivity gains are often derived from mere extrapolations of historical statistics.

Revenue cap regulation is a variant of the price cap approach for multi-product firms. Electricity grid operators are multi-product firms because they provide grid connection to customers at different grid levels. Yet, the provision of these services is done using a (partly) common infrastructure. Therefore, it is both simpler in application and more reflective of cost structures if not the prices of single products are regulated, but instead the overall revenue. This leads to the basic formulation of a revenue cap as follows:

$$R_t^{\mathrm{RCp}} = R_0 \cdot (1 + \mathrm{RPI}_t - (t - t_0) \cdot X). \tag{6.6}$$

The essential advantage of such a regulation scheme is that the revenues of the grid operators in year t are decoupled from their cost during the same period. Hence, the grid operator has no incentive to inflate their costs, rather they have a strong incentive to minimise costs, given that their profit will correspond to the difference between the fixed revenue cap and their actual costs. Therefore, the term "incentive regulation" has been coined for this type of regulation.

Both practical experience and more advanced theoretical reasoning however indicate that the application of this regulatory recipe is not that straightforward: given that estimates of future productivity gains are subject to considerable uncertainty, the application of a specific price or revenue cap formula should be limited to a pre-specified regulation period. Otherwise, there is a substantial risk that the operator obtains huge excess profits if the possible productivity gains are underestimated. But also the opposite risk has to be taken seriously, namely that the operator ends up in financial distress if ex-ante estimates of productivity gains turn out to be too optimistic.

Therefore, the duration of a regulation period is usually set to three to five years in practice. A new reference price or revenue level is set for the next regulation period based on cost considerations. This may however induce a so-called **ratchet effect**: since the regulated entities, i.e. the grid operators, anticipate that any cost decrease they achieve during one regulation period will induce lower (i.e. more ambitious) reference levels in the following regulation periods, they will not engage in cost reductions that require continued additional efforts. The shorter the regulation period, the more pronounced is this ratchet effect. Consequently, longer regulation periods provide more substantial efficiency incentives – at the expense of higher risks as stated above.

With any limited duration of a regulation period, the necessity of setting a new reference level also implies problems similar to those incurred in cost-of-service regulations. Notably, the criterion of "used and useful" expenditures will have to be applied by the regulator who will have to struggle with the problems of asymmetric information.

Yardstick competition as proposed first by Shleifer (1985) is a possibility to avoid some of the difficulties of conventional revenue or price cap approaches. The revenue level is thereby set by using an average cost value of similar firms as a reference. This mechanism also decouples the revenue level of the firm from its own cost level and thus provides incentives for continued cost reduction efforts. Yet, it is only applicable if an adequate number of sufficiently similar firms is available for comparison purposes. One may argue whether Germany's more than 800 distribution grid operators are sufficiently homogenous to enable an adequate comparison. But for one single TSO per country (e.g. France), this approach will not work.

Sliding scale regulation is a possibility to combine cost-based regulation with incentive schemes (cf. e.g. Schmalensee 1989; Laffont and Tirole 1993; Lyon 1996). Its basic linear version may be seen as a weighted combination of a cost-based and an incentive-based scheme. Formally, this may be written

$$R_t^{\mathrm{SSc}} = (1 - \alpha) \cdot R_t^{C+} + \alpha \cdot R_t^{\mathrm{RCp}}. \tag{6.7}$$

The sliding scale parameter α then gives the weight of the incentive-based scheme in the overall revenues. The higher its value, the more emphasis is laid on incentivising the grid operator, since cost overruns will only be recovered to a lower extent through revenue increases.

6.1.3 Practical Challenges of Performance-Based Regulation

There are numerous aspects in the application of the aforementioned concepts of incentive regulation. Subsequently, we limit the discussion to three major points: the issue of heterogeneous network operators, the question which parts of the costs should be subject to performance-based regulation and the need for a quality regulation.

6.1.3.1 Heterogeneity of Network Operators and Benchmarking

In principle, multiple network operators may contribute to alleviating the regulator's problem of asymmetric information. Indeed, the regulator may use the multiplicity of observations on different grid operators to derive benchmark performance measures. This is done in a rather straightforward way in the yardstick competition approach described above. There the average of (similar) grid operators is taken as a reference value.

Beyond that, more sophisticated approaches may be applied that consider that not all grid operators are alike. Usually, the term **benchmarking** is used to designate such methods.

Benchmarking is a method for coping with grid operators' heterogeneity by adjusting the cost for some observable characteristics of the different grid operators. With the help of benchmarking, inefficiencies in the cost structures of grid operators are to be identified. Hence, it may be used in conjunction with yardstick competition to set an adjusted revenue level, as is the case in Norway since 2007. Or it may also be used in connection with revenue cap approaches to determine firm-specific paths for productivity gains – this has been the practice in Germany since 2009. Different statistical techniques may be used to arrive at the benchmarks, among which the most frequently used are **Data Envelope Analysis** (DEA) and **Stochastic Frontier Analysis** (SFA). Whereas DEA is a nonparametric approach related to optimisation problems, SFA is more related to regression methods (cf. e.g. Bogetoft and Otto 2011).

European regulators have repeatedly applied these techniques to electricity grid operators, yet results have been heavily criticised, primarily by practitioners (cf. also Kuosmanen et al. 2013). One of the most frequent criticisms is that the results may be strongly impacted by outliers and not robust against specification errors. For example, the German regulator has responded to these criticisms by taking a best-of-four approach when assigning an efficiency level to each grid operator. The four alternative benchmark values are obtained by combining the DEA and SFA methods with two different cost bases (see next section).

6.1.3.2 Cost Base for Regulation

Applying the aforementioned methods raises two additional major questions in practice that have not been discussed so far. Both are related to the basic concept of the cost of a firm.

The first key issue is whether the incentive regulation schemes discussed previously should be applied to the total cost of a firm, i.e. TOTEX (see Sect. 6.1.2.3 for terminology), or only to the variable part, i.e. OPEX.

From a welfare perspective, the consideration of the total cost is the more obvious choice. Yet, companies tend to argue that they may not be able to influence their capital expenditure in short to medium run, given the long lifetime of assets. Thus, a comparison based on TOTEX may disadvantage some firms over a longer period – although this may be softened in a revenue cap scheme by requiring only limited productivity gains per year for firms that are found to be inefficient in a benchmarking exercise. On the other hand, a pure OPEX-based incentive regulation provides distorting incentives: the network operators will aim to reduce their operating expenditures whereas CAPEX is not touched – in extremis, there will be an excessive substitution of benchmarked OPEX by CAPEX, which are subject to a cost-based regulation.

When including the capital expenditures in the incentive scheme, the definition of these expenditures is a key aspect. But even under other regulatory regimes, the so-called **regulatory asset base** (RAB) is pivotal in regulation. What items are included in that asset base, what lifetimes are assumed for the computation of depreciations and are the capital expenditures derived directly from the depreciation according to the company accounts? The answers to these questions have a major impact on the profitability of the regulated firms, their incentives to invest and the outcomes of the regulatory benchmarking.

6.1.3.3 Quality Regulation

Whereas companies tend to cut costs under a proper incentive regulation scheme, they have an incentive to inflate their expenditures under cost-based regulation (see Sect. 6.1.2.3). Consequently, it is unlikely that the quality of service will be put at risk under cost-based regulation schemes. However, this type of regulation does not guarantee by itself the most efficient use of revenues for upholding the quality of service. Yet, the fear of being blamed for some partial or full blackout is likely to be a strong motivation for maintaining at least some quality level.

In incentive regulations, this motivation may not be strong enough to counterbalance profit maximisation goals. Therefore, an incentive regulation has to be complemented by some form of quality regulation. Usually, three dimensions of quality are distinguished:

- **network reliability**, i.e. the absence of interruptions,
- **network performance**, e.g. in terms of voltage stability or power harmonics,
- **service quality**, e.g. response time to customer requests and complaints.

The emphasis is thereby on the first one. Yet this quality regulation has to face three challenges: the time lag between investment (cuts) and quality impacts, the stochasticity of outage events and the choice of appropriate quality indicators.

As quality indicators for **network reliability**, the indicators defined in Sect. 5.1.4 are commonly used by regulators (cf. CEER 2015):

- SAIFI: System Average Interruption Frequency Index,
- SAIDI: System Average Interruption Duration Index,
- CAIDI: Customer Average Interruption Duration Index,
- ENS: Energy not supplied.

The concepts mainly differ in the weighting of different interruption events affecting various customers (see Sect. 5.1.4). Moreover, the exact definitions applied by different regulators differ in several aspects, notably whether short interruptions (e.g. below 3 min) are counted or whether events attributed to "force majeure" such as extreme weather situations are included.

From a welfare maximisation perspective, energy not supplied should be weighted by the marginal utility it provides to customers. In system planning, this is also known as the **value of lost load** (**VOLL**). Rough estimates range between 2 and 10 €/kWh for industrialised countries. Empirically this value could be determined by measuring the willingness to pay of customers for non-interruption of service.[2] However, this is hardly put into practice so far, since the willingness to pay varies a lot between customer groups and is likely to be time-varying and undoubtedly challenging to measure (cf. Kjolle et al. 2008; Shivakumar et al. 2017).

Suppose ENS (or another quality indicator) is considered to be a sufficiently accurate indicator. Then rational grid operators will make consistent and optimal choices if they are penalised for all service interruptions according to the corresponding willingness to pay of the customers. This is even true in the presence of time lags and stochasticity since full rationality implies anticipation of future penalties with best available probability estimates. Yet assuming such an entirely rational behaviour is rather heroic than realistic, and therefore, quality penalties and rewards are typically restricted to some single-digit percentage of the revenue cap. This is of particular relevance for small grid operators, where **stochasticity** has a higher relative impact due to the absence of levelling effects related to the law of large numbers (cf. Schober et al. 2014).

[2] More precisely, this should be qualified as a (monetary) willingness to accept service interruptions (cf. e.g. Horowitz and McConnell 2003 for the distinction between willingness to accept and willingness to pay).

6.1.4 Principles of Network Pricing

So far, prices for grid services and the corresponding revenues have been discussed either under the assumption that there is just one product delivered by the grid operator (and thus one price) or alternatively with an exclusive focus on the total revenue and not on its split according to different products or customer groups. But in practice, the question of who should be charged for grid usage and on what basis is very relevant since electric grids connect multiple producers with many consumers. A fundamental question is whether exclusively consumers should pay for their usage of the grid infrastructure or whether producers should also be charged.

To derive adequate answers to these questions, Sect. 6.1.4.1 starts by explaining the rather general, formal concept of Ramsey prices as price differentiation between products or customer groups under the assumption that each customer only buys one product. This is followed by a more informal discussion of different products and services delivered to each customer and the corresponding price components in Sect. 6.1.4.2. In Sect. 6.1.4.3, an application of Ramsey pricing to a stylised network is discussed, whereas Sect. 6.1.4.4 discusses the role of different price components on the example of a low-voltage grid, including notably also so-called prosumers. The practical implications for network tariffs, notably focusing on future smart grids, are then outlined in Sect. 6.1.4.5.

6.1.4.1 Ramsey Pricing

The so-called Ramsey rule goes back to the British mathematician Frank Ramsey (1903–1930). A related rule also named after Frank Ramsey is applicable in the context of optimal taxation issues. The common underlying question is how a monopolist should fix prices (or tax rates) to maximise welfare under a given budget constraint.

This problem arises in the case of a grid operator since the basic rule for efficient pricing, namely to set prices equal to marginal costs, does not fulfil the budget constraint. As stated in Sect. 6.1.1, the need for regulation of grid operators arises from the fact that grid costs are subadditive. Even the stronger condition that marginal costs are below the average per-unit cost holds in the case of grid operators. This implies that setting prices equal to marginal costs will result in revenues for grid operators, which do not cover their costs. If there is a single product with a single price, the problem may be depicted as shown in Fig. 6.2. The first-best solution of setting prices equal to marginal cost results in the equilibrium indicated by point F. Yet at the corresponding price p^*, the grid operator incurs losses equivalent to the hashed area, corresponding to the difference between average cost and price multiplied by the equilibrium quantity.

The optimal solution satisfying the budget constraint, i.e. without losses incurred by the grid operator, is given in the one-product case by point S. This **second-best** solution (cf. Sect. 6.2.3.1) corresponds to setting the price equal to average per-unit cost.

If multiple products i (grid services) are sold to different customers, the second-best solution is not that obvious. It may be obtained by maximising the

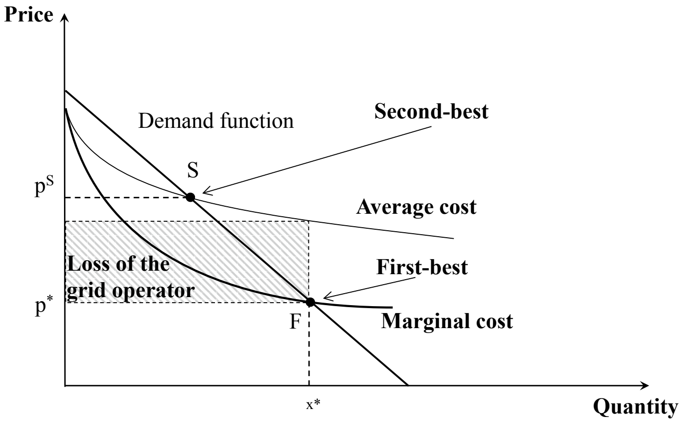

Fig. 6.2 First-best and second-best solutions for grid tariffication

economic surplus (welfare) W under a budget (non-loss) constraint. The economic surplus may be derived as the sum of consumer and producer surpluses over all products. This is equivalent to obtaining the integral willingness to pay for the delivered quantities q_i and deducing joint production cost C:

$$W = \sum_{i=1}^{N} \int_{0}^{q_i} p_i(q_i)\mathrm{d}q_i - C(q_1 \ldots q_i \ldots q_N). \tag{6.8}$$

Thereby the inverse demand functions $p_i(q_i)$ are used to represent the willingness to pay (and thus marginal utility of customers) for the different products.

The budget constraint of the grid operator then corresponds to:

$$\sum_{i=1}^{N} p_i q_i - C(q_1 \ldots q_i \ldots q_N) = 0. \tag{6.9}$$

Using the Lagrange multiplier approach and determining first-order optimality conditions, one obtains after some rearrangements the Ramsey pricing rule:

$$\frac{p_i - c_i(q_1 \ldots q_i \ldots q_N)}{p_i} = \frac{k}{|\varepsilon_i|} \quad \forall i. \tag{6.10}$$

The left-hand side thereby corresponds to the relative markup over the marginal cost $c_i = \partial C / \partial q_i$. And this markup is found to be inversely proportional to the price elasticity of demand $\varepsilon_i = \frac{\partial q_i}{\partial p_i} \cdot \frac{p_i}{q_i}$. The proportionality constant k thereby has to be chosen such that the budget constraint is fulfilled.

According to this Ramsey rule, those costs that are not directly attributable to one product should hence not be distributed equally or proportionally to the customer groups, but rather those should pay most that have the lowest evasion or substitution tendency. This rule minimises the so-called dead-weight losses associated with government intervention in markets, although it may result in prices and distribution effects that are perceived as unfair. The implications of applying (or not applying) this rule will be discussed in Sect. 6.1.4.5.

6.1.4.2 Capacity, Energy and Other Prices for Grid Usage

We may push the cost allocation and pricing one step further by arguing that a single customer does not obtain one single service from the grid but rather different services depending on the hour of the day or the year when she or he consumes or produces electricity.

A widely applied principle is that consumers are only charged the costs of the grid voltage levels they are using. This way, a large industrial customer, who is directly connected to the high-voltage grid, will not be charged the cost of the low-voltage grid. Since the electricity a large industrial customer consumes does not transit the low-voltage grid, this has been true in conventional power systems with little small-scale distributed generation, leading to reverse flows in the grids. Households and other small electricity users connected to the low-voltage grid are contrarily charged the cost of the low-voltage grid and a fraction of the costs of higher voltage grid levels – since large proportions of the energy they are using is transported via the higher level grids.

On the other hand, most grid costs depend on the maximum grid capacity needed over the year or even several years since this grid capacity is a key design choice in the grid and determines its investment. The consequence for grid tariffs is that customers should be charged for their contribution to maximum capacity on the one side and for the energy they get transported through the grid on the other side. And if there are costs that are independent of power and energy provided, those should be charged separately in a lump-sum connection fee.

Conventional grid tariffs in many countries around the world are designed in line with these general considerations: they are two- or three-part tariffs including[3]:

- an annual base fee,
- a capacity fee and
- an energy fee.

However, these basic tariff elements need further reflection to obtain an adequate tariff system. An interesting aspect regarding the capacity fee is whether it should be paid based on the individual maximum capacity or according to the contribution to the maximum system load. The first approach is currently implemented in

[3] Also retail prices frequently are made up of the same components as discussed in Sects. 3.1.6 and 7.4.7. This is a consequence of the fact that even in deregulated electricity markets with unbundling, retail contracts mostly also include the payment of the grid charges.

Germany, the second in the UK, and justifications may be given for both. Another aspect that limits the applicability of analytical solutions based on marginal calculus is the frequent indivisibility of investments in the grid – e.g. building a new transmission or distribution line comes at some fix cost per km, almost independently of the actual capacity of the line. A further, very practical aspect has so far been the lack of automatic meter reading systems ("smart meters") in the case of households and other low-voltage grid users. With the conventional electromagnetic meters, the capacity used cannot be measured easily and is therefore frequently not charged. This has led to tariff schemes with relatively high energy fees.

Therefore, a combination of economic optimisation calculus, engineering rules of thumb and considerations of practicability and acceptability is needed to determine an adequate network tariff system.

6.1.4.3 Application: Ramsey Pricing in an Electrical Network

We consider a stylised network with two voltage levels: at the higher level, i.e. the transmission grid, there are three grid nodes with the generators and loads connected as depicted in Fig. 6.3. The lower-level distribution grid is only considered for one of the transmission grid nodes. The key parameters for the grid users are summarised in Table 6.1.

Since the distribution grid is only used by the grid users located in area A2.1, potential costs of this lower-level grid are attributable to the two user groups, solar panels (A2.1) and small and medium consumers (A2.1). Yet the costs of the transmission grid cannot be attributed clearly to any of the grid users since Kirchhoff's laws govern the power flows (see Sect. 5.1.2.1). Moreover, the power flows may vary over time or according to meteorological conditions. This raises the question how to determine appropriate reference capacities. Yet, we assume this question to be solved and consider the reference capacities given in Table 6.1 to reflect properly the grid usage at some reference cost or price level $c_0 = p_0$. This reference cost level may be thought of as some pure energy procurement cost (respectively sales revenue in the case of generators), i.e. based on a wholesale market price disregarding grid costs (see Sect. 7.1). It is as such applied to all grid users in the example. As indicated in Table 6.1, the reference cost level is set at 60 €/MWh. The total grid cost is assumed to be independent of the produced and consumed quantities and equal to 1,000,000 €/h on average. Dividing this cost by the total dimensioning capacity Q, grid costs correspond to 20 €/MW/h.[4]

The application of Ramsey pricing now aims at an optimal distribution of these latter costs to the different grid users. This requires in a first step the reformulation of Eq. (6.10) so that the unknown p_i is expressed as a function of the single unknown variable k:

[4] We use hourly values to keep the numbers simple. Those can easily be transformed into annual numbers by multiplying with the number of hours of a year, i.e. 8760. As the basis of our calculations is an average hour, we also disregard the distinction between capacity, energy and other grid price components as usual in simple models of Ramsey pricing.

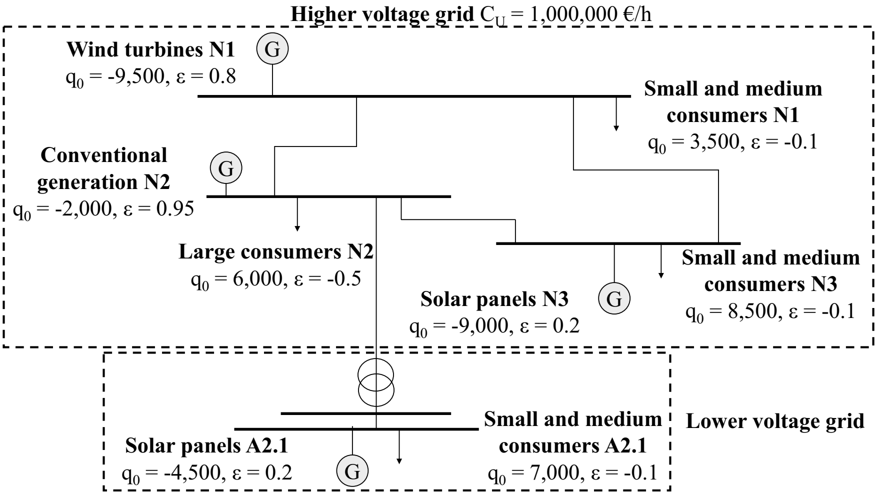

Fig. 6.3 Schematic representation of a two-level grid

Table 6.1 Key characteristics of grid users, grid costs and reference costs

Node higher voltage grid	Area lower voltage grid	Grid user	Grid usage [reference capacity in MW (q_{i0})]	Price elasticity (ε_i)
N1	–	Wind turbines	−9,500	0.8
	–	Small and medium consumers	3,500	−0.1
N2	–	Conventional generation	−2,000	0.95
	–	Large consumers	6,000	−0.5
	A2.1	Solar panels	−4,500	0.2
	A2.1	Small and medium consumers	7,000	−0.1
N3	–	Solar panels	−9,000	0.8
	–	Small and medium consumers	8,500	0.1
All		Total (abs. values)	$Q = 50,000$	
Overall cost/ market value	Reference	$c_0 = p_0 = 60$ €/MWh		
	Grid	C = 1,000,000 €/h, i.e. C/Q = 20 €/MW/h		

$$p_i = \frac{c_0}{1 + \frac{k}{\varepsilon_i}} \quad \forall i. \tag{6.11}$$

Thereby we have used the substitution $|\varepsilon_i| = -\varepsilon_i$ which is valid for consumers who (mostly) have negative price elasticities (see Sect. 3.1.4). Yet with this reformulation, the approach is also valid for producers where grid fees would reduce market revenues. Additionally, the dependency of the quantities q_i on the prices p_i needs to be described. Here an iso-elastic formulation is assumed:

$$q_i = q_{i0} \left(\frac{p_i}{p_0} \right)^{\varepsilon_i} \quad \forall i. \tag{6.12}$$

The reference prices p_0 are set to the same value c_0 as discussed before. Yet the revenue of the grid operator from customer i is only based on the difference between the price p_i and the reference price p_0, as the reference price reflects wholesale costs/revenues. Hence the necessary condition for grid revenue adequacy becomes after inserting the two previous expressions and rearranging:

$$\sum_{i=1}^{n} (p_i - p_0) q_i = \sum_{i=1}^{n} \left(\frac{1}{1 + \frac{k}{\varepsilon_i}} - 1 \right) \left(\frac{1}{1 + \frac{k}{\varepsilon_i}} \right)^{\varepsilon_i} p_0 q_{i0} = C. \tag{6.13}$$

This is now a single equation for the single unknown k. It cannot be solved analytically, yet a numerical solution is straightforward using a spreadsheet program like Microsoft Excel or another computation software. This is true since each term of the sum on the left side is found to be monotonously increasing with k, as long as k is positive and strictly smaller than the absolute value of the smallest negative price elasticity ε_i. Hence, the sum increases monotonously from (close to) zero to infinity and there is a single optimal value k. The corresponding calculations are implemented in the spreadsheet *RamseyPricing.xlsx* contained in the electronic appendix to this chapter. Using the function "search target value", the user can determine the optimal solution given in Table 6.2.

From the results, it is obvious that grid users with low price elasticities pay much higher markups than those with high price sensitivity – or producers must accept much higher discounts. In our example, the small and medium consumers bear a 42.5% surcharge, whereas it is only 8.5% for the large consumers who have a five-time higher price elasticity. Wind and conventional producers in our example are even more price-sensitive and therefore only face discounts of 5.3% and 4.5%, respectively. As stated in Eq. (6.10), the markups and discounts are directly proportional to the inverse of the price elasticities.

In this vein, it hence seems justifiable that producers are (almost) exempt from grid fees.[5] Yet even for consumers, the practical application of Ramsey pricing faces serious difficulties: first, the price elasticities are generally not known and not

[5] Note that we have considered wholesale market prices to be exogenously given, independent of generator decisions. This is obviously not true in reality. Yet an endogenous treatment of market

Table 6.2 Results of Ramsey pricing for the application example

Node higher voltage grid	Area lower voltage grid	Grid user	Final network price (in €/MW/h)	Relative markup (%)
N1	–	Wind turbines	57.0	−5.3
	–	Small and medium consumers	104.4	42.5
N2	–	Conventional generation	57.4	−4.5
	–	Large consumers	65.6	8.5
	A2.1	Solar panels	49.5	−21.3
	A2.1	Small and medium consumers	104.4	42.5
N3	–	Solar panels	49.5	−21.3
	–	Small and medium consumers	104.4	42.5
Calibration parameter		$k = 0.04255$		

easily measurable. This is particularly true as the relevant elasticities regarding irreversible and long-term investment in grid infrastructure are long-run price elasticities. Their estimation requires long price series, which are prone to structural breaks. The second issue is (perceived) fairness. This is not an issue in the framework of mainstream economics since distributional effects should be handled separately from pricing issues according to the fundamental theorems of welfare economics (see the introduction to Sect. 6.1). Yet as grid operators are either state-owned or regulated utilities, the decision on grid tariffs is also a political one. In particular in the presence of very limited empirical evidence, the case for Ramsey pricing as a form of discriminatory pricing is challenging to defend in the public debate.

Our example of Ramsey pricing could be extended to the lower grid level contained in Fig. 6.4. Yet, we leave it aside to limit complexity and focus in the following subsection on the challenges arising in low-voltage grids, notably in connection with so-called prosumers.

6.1.4.4 Application: Network Tariffication in Low-Voltage Grids

The heterogeneity of grid users in a future **smart grid** further complicates identifying efficient and cost-reflective prices as those discussed previously under the concept of **Ramsey pricing**. Notably, the presence of prosumers raises new challenges.

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equilibrium would require a substantial extension of the classical Ramsey pricing model, making use of the market equilibrium models introduced in Sect. 7.1.

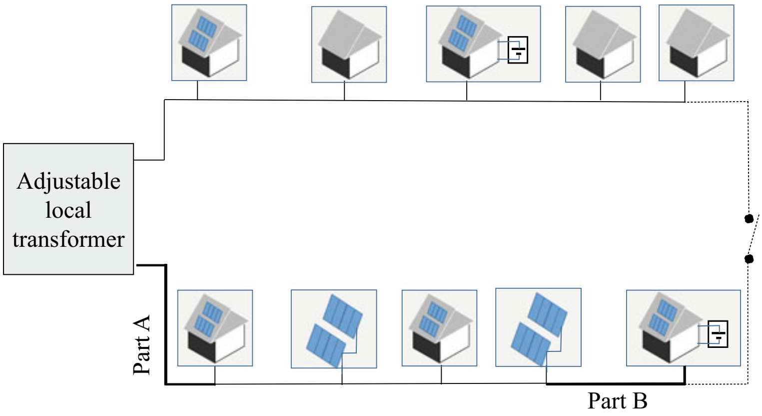


Fig. 6.4 Schematic representation of a low-voltage grid

Prosumers are a rather new type of grid users – the term has been coined to designate customers that not only consume electricity but also operate on-site generation facilities, notably PV or CHP systems. Moreover, they may have some flexibility in their generation and consumption pattern, e.g. through the use of storage possibilities.

To illustrate the arising challenges for network tariffication, we consider an exemplary low-voltage grid as depicted in Fig. 6.4.

This grid consists of

1. One transformer as a connection point to the higher voltage grid levels
2. Several consumption points (households)
3. Several production units (PV-panels) associated with households
4. Several production units (PV-panels) not associated with households
5. Some storage devices (batteries) associated with production units.

The grid is constructed as a closed loop, but the switch at the end of the line is open in standard operation mode. It is only closed if there is an interruption somewhere else in the circuit, so that **N-1 secure** operation is possible. In what follows, we yet disregard faults and other contingencies and focus on regular operation.

Without a complete formal treatment, we subsequently aim to explain the challenges of finding the correct "prices for the grid services". We do so by starting with simple configurations and adding complexity step by step.

(a) **Transformer plus consumers**: this is a simplistic version of a grid to start dealing with the question: How should we fix the grid tariff in an efficient and cost-reflective way? The answer begins by stating that the load peak in the system mainly drives the transformer size. Hence, each consumption point should pay a share of the transformer cost proportional to the (expected) contribution to the transformer peak load. In the case of consumers with similar consumption profiles, the contribution to the transformer peak load will be proportional to the households' own peak load. Hence, there should be a (part of the) capacity charge paid per kW of (non-coincident) peak load in the household. If the households have different consumption profiles, this is yet no longer the optimal pricing scheme. Then, the capacity charge should be paid on the basis of the (average) contribution to the system peak load, i.e. the **coincident peak load** (cf. Sect. 3.1.6).

As long as consumption is purely random and effectively not controlled by the consumer nor the consumer can avoid the grid charge through relocation, the height and structure of the capacity charges do not impact the economic efficiency – in the Ramsey formula, the price elasticity is equal to zero. Yet as soon as consumers may react, e.g. by rescheduling load, capacity charges have to reflect contributions to system load peaks.

(b) **Energy instead of capacity pricing**: traditional grid tariffs in the low-voltage grid often charge the users with an energy fee instead of a capacity fee – not least since traditional meters only measure the energy flowing through the wire and do not keep track of load maxima or loads per time interval. Charging the customers proportional to their energy consumption instead of their contribution to system load again makes no difference in efficiency, as long as the consumers have no capability to react. Such a pricing then also does not affect overall costs (and thus economic efficiency) even if it may be perceived as unfair, i.e. the resulting distribution of costs is not in line with preconceptions of equitable cost sharing. But suppose households have opportunities to adjust their consumption. In that case, a time-independent energy price does not provide an adequate signal for doing so – as it does not incentivise consumers to shift their load away from the peak load period.

(c) **Adding connection lines**: if the previous system consisting of a transformer and several consumption points is now complemented by the (underground or overhead) lines necessary to supply the individual households, the question arises of who should pay for these lines. In Fig. 6.4, part A of the line serves all households of this feeder, while part B is only needed in regular operation to supply one household. In the logic of cost-reflective pricing, the costs of part A should hence be borne by all households, those of part B yet only by the household attached to it. This discriminatory pricing would be efficient since it would put more substantial incentives on capacity reductions by the consumers beyond part B of the line, where line upgrades are more costly for the customers. Yet this perspective is only correct if we consider the location of the transformer as fixed. This is undoubtedly true in the short to medium term but may not hold in the long run. Then also, the justification for discriminatory pricing in terms of economic efficiency gets weaker.

(d) **Addition of (renewable) generation units**: What changes in terms of efficient grid pricing if we now include some generation units in the system? A differentiation is necessary to answer this question:

If the generation follows the load and reduces the peak load on the transformer and the lines, it contributes to grid cost savings. It may then earn remuneration from the grid – corresponding to the grid capacity price multiplied by the (expected) reduction in grid peak load.

Another situation occurs if the generation is driven by natural variability as is the case for PV and wind. In that case, it is unlikely that the distributed generation will predictably reduce the load peak.[6]

In grids with high shares of renewables, even the power flow may be reversed during periods with high renewable infeed. As long as the transformer capacity is not exceeded (and voltage limits are not violated) by the reverse flows, grid costs are not driven by the renewable infeed and generation should therefore not be allocated any grid costs – except for a payment covering the transportation losses in the grid, which we omitted so far.

As soon as the transformer (or another critical element) is yet more heavily used during the period of maximum reverse flow than in the peak load situations, the long-run costs of the grid are driven by the maximum reverse flow. Hence cost-reflective pricing would imply charging the generators in the grid for their (expected) contribution to peak reverse flow and conversely paying the consumers for the relief they provide in that situation.

(e) **Curtailment of (renewable) generation**: the situation described at the end of the previous section (reverse flows determine capacities of grid elements) would yet provoke adaption reactions from renewable producers: instead of paying high grid capacity charges they would curtail their production in the peak reverse flow situations, as long as the revenues from sales on the wholesale market (or under a renewable support scheme) are lower than the capacity charges. In the optimum, capacity charges would then be paid by consumers and generators with higher per kWh charges for the consumers. This is a consequence of their lower price elasticity (i.e. their higher willingness to pay for unlimited grid access) and the Ramsey pricing rule (see Sect. 6.1.4.3). Obviously, also the grid should be extended as long as the aggregate willingness to pay exceeds the grid construction costs.

(f) **Addition of storage or other flexibility providers**: already the addition of limited (curtailment) flexibility in the previous step has led to differentiated grid charges applicable for different time segments (peak load and peak reverse flows). The situation becomes even more complicated if storage is used to (partly) substitute grid investments. Three challenges arise:

1. multi-period variable grid charges
2. lumpiness of grid investment
3. strong location-dependency of grid-related storage value.

[6] Grids with high air-conditioning and cooling loads may be an exception to the rule, if the load peak coincides with periods of high solar radiation and hence high PV infeed. The so-called duck curve observed in California (cf. e.g. IEA 2019) yet suggests that even in such grids the coincidence is far from being perfect: in California, the peak in electricity consumption occurs in the early evening, when people return from work and turn on air-conditioning and other appliances at home.

The first point is the relatively straightforward generalisation of the point made previously on simultaneous scarcity pricing in different periods. The second one, by contrast, emphasises that the marginal calculus that may be used to underpin the first point is in reality hardly appropriate, given that grid operators invest in discrete pieces of hardware. If the investment is not necessary, the marginal value of substitutes is (close to) zero. If the investment is unavoidable, the marginal value becomes infinite. However, there may be a finite nonzero value for alternative lumpy investments (cf. Böcker et al. 2018). Finally, the third point emphasises that these considerations will be strongly dependent on the exact grid topology and congestion situation. These considerations are related to so-called nodal pricing which is discussed in Sect. 10.8, albeit nodal pricing usually focuses on short-run marginal cost.

6.1.4.5 Implications for Practical Grid Tariff Structures

The general principles and applications discussed in the preceding sections indicate elements of current and future grid tariffication, although no simple recipe for optimal tariff structures may be directly derived. Key practical implications to be retained include notably:

Consumers generally have a lower price elasticity for electricity than producers – this provides a rationale for charging mainly (or even exclusively) consumers with the markup over short-run marginal costs.

Producers should nevertheless be charged at least the marginal grid cost they are causing. This includes the direct connection costs (so-called shallow connection charges) but may also include indirect costs caused by new generation in other parts of the network, e.g. for grid expansion ("deep connection charges"). This leads to a locational component in grid tariffs that has been in place in the UK for more than a decade as a so-called G component. The calculation of such a component should be based on the long-run marginal costs for grid operation, renewal and expansion. However, such a grid tariff based on long-term costs provides only imperfect signals in terms of short-term congestion management (see Sect. 10.6.2).

For *electricity storage*, e.g. pumped hydropower stations or battery storage, similar considerations apply as for generators. They are rather price-sensitive and should therefore be charged mostly the direct and indirect connection cost.

For *prosumers* as grid users who not only consume electricity but also operate on-site generation facilities, notably PV or CHP systems, the design of grid tariffs is of particular relevance: high energy-related charges (see Sect. 6.1.4.2) lead to strong incentives for self-generation, which effective grid cost savings might not justify.

The increasing share of distributed generation and prosumers therefore challenges the existing grid tariff structures. This is particularly true in the ongoing transformation of the electricity system. If there is considerable uncertainty about the future generation mix and the corresponding costs, long-run marginal grid costs are also uncertain. Setting adequate incentives here without jeopardising innovation through frequent rule changes is undoubtedly a key challenge for regulation and grid management in future (see also Sect. 12.3).

6.2 Environmental Effects and Environmental Policy

Energy conversion leads to different environmental impacts, especially when transforming primary energy carriers like coal, gas, oil or uranium. The magnitude of these problems strongly depends on the technologies and energy carriers used. As long as the originator of the environmental impact does not have to bear the costs related to this impact, he will not take these costs into account. This constitutes a form of market failure that has to be addressed by governmental intervention, i.e. by the implementation of different policy instruments.

Section 6.2.1 addresses the problem of externalities. Different emissions caused by energy conversion processes based on fossil fuels, the corresponding environmental impacts and emission reduction technologies are discussed in detail (Sect. 6.2.2). Section 6.2.3 then reviews different policy instruments, with more specific considerations in Sect. 6.2.4 for climate change.

6.2.1 Externalities

In the market-oriented perspective of mainstream economics, the effects of economic activities on parties not involved in the underlying business transaction are called **externalities**. These externalities can be negative or positive for the third parties and are not compensated by the responsible entity.[7] Therefore, externalities lead to inefficient market outcomes (see Sect. 6.1.1) and induce market failures.

In the case of emissions from energy production, primarily negative externalities arise. As long as the producers of emissions do not have to bear the costs from these externalities, they will not consider them within their production process. This might lead to a situation where too many emissions are produced, a situation not being the social optimum. Theoretically, the emissions should be reduced to the economic optimum of emission reduction costs and damage costs, which will usually not be a reduction of the emissions to their minimum. From Fig. 6.5 it can be seen that the optimal emission level is e^* and the corresponding marginal abatement costs and marginal damage costs are t^* (for the interpretation of t^* see Sect. 6.2.3.1).

If negative externalities are monetarised, external costs are obtained. The costs are called "external", because they are not reflected in the market prices of the corresponding business transactions. Therefore, the marginal private production costs are below the marginal social production costs, which include private and external costs, leading to the dilemma (or market failure) that too many goods with negative externalities (x_0) are produced in the market equilibrium and the corresponding price (p_0) is too low (see Fig. 6.6).

Externalities can also be explained with the help of the theory of **public goods** (cf. e.g. Feess and Seeliger 2013, pp. 35–41). In general, goods can be differentiated with the help of the criteria rivalry and excludability into private goods, club goods,

[7] The "tragedy of the commons", i.e. the overgrazing of common land, is described in a seminal paper by Hardin (1968).

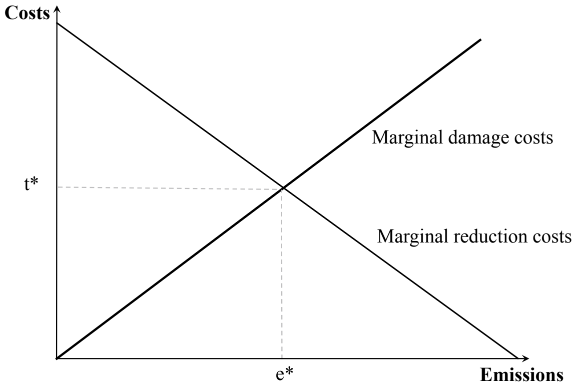


Fig. 6.5 Marginal damage costs versus marginal reduction costs. *Source* Own illustration based on Perman et al. (2003, p. 173)

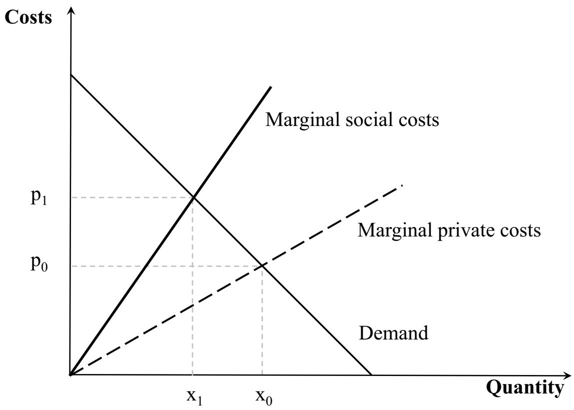


Fig. 6.6 Marginal private versus marginal social costs of production. *Source* Own illustration based on Fritsch (2018, p. 113)

common-pool resources and public goods (see Table 6.3). Whereas the owner of a private good enjoys private property rights, everyone can benefit from public goods. Many environmental goods (e.g. clean air) are seen as public goods, satisfying the corresponding constitutive criteria: non-rivalry and non-excludability. Sometimes, the extensive use of these goods already limits the benefit for one consumer by another. In such a case, the criteria of non-rivalry is no longer fulfilled leading to a classification of the corresponding environmental good as a common-pool resource. Public goods and common-pool resources lead to the so-called free-rider problem because one can benefit from this good even without paying for it. Therefore, there is hardly any incentive for firms or households to provide public goods, and the opposite is true in the case of so-called public bads

Table 6.3 Differentiation of goods according to the criteria rivalry and excludability

	Rivalrous	Non-rivalrous
Excludable	Private good, e.g. ice cream	Club good, e.g. subscription television
Non-excludable	Common-pool resource, e.g. fishery outside territorial waters	Public good, e.g. lighthouse

Source Own illustration based on Perman et al. (2003, p. 126)

(e.g. polluted air), where incentives are missing to avoid the negative externalities for other parties.

The quantification of external costs and their allocation to an economic activity gives rise to various empirical problems. First, the causal relationship between an economic activity and an externality has to be established. But even nowadays, many negative environmental externalities are not fully understood. In addition, sometimes the causal relationship is difficult to prove, e.g. because only the interaction of different economic activities induces the observed negative externality or because in particular situations additional emissions, caused by production processes, will even reduce some negative externalities. Furthermore, it can be extremely challenging to quantify the damage caused by an externality, e.g. in the case of a changed overall landscape appearance caused by the visual impact of (wind) power plants or overhead transmission lines. Therefore, besides the endeavour to directly estimate the **damage costs** (e.g. the economic losses caused by forest decline or casualties due to acid rain), so-called **avoidance cost** methods, which calculate the costs of alternative measures to avoid negative externalities, e.g. the costs of flue gas cleaning to prevent the precursor emissions of acid rain, are used. Another alternative is to determine the value of a good with the help of preference valuation methods (stated preferences and revealed preferences). The methodology of revealed preferences tries to identify people's preferences[8] by observing their purchasing behaviour, whereas in contingent valuation surveys people have to state their **willingness to pay** or their willingness to accept. Furthermore, the quantification of the external costs has to deal with the problem that frequently some damage will only become evident in the future, e.g. in the case of global warming. Then the question arises at which rate such damage should be discounted.

6.2.2 Emissions, Environmental Impacts and Emission Reduction Technologies

Converting energy carriers, e.g. into electricity and heat, leads to so-called **energy-induced emissions** in contrast to process emissions arising, e.g. in industrial production processes like cement production. By burning fossil fuels, greenhouse gas emissions (notably CO_2) and pollutants (e.g. NO_x) are produced

[8] These preferences will differ from person to person and may vary over time.

Table 6.4 Main emissions from different fossil fuels

	SO_2	NO_x	CO	VOC[a]	Particulates	CO_2
Coal	X	X	X	X	X	X
Oil	X	X	X	X	X	X
Natural gas		X	X	X		X

[a] Sometimes VOCs (Volatile Organic Compounds) are differentiated into methane (CH_4) and the remaining non-methane volatile organic compounds (NMVOC)

(so-called primary pollutants; see Table 6.4), which might lead to environmental impacts.

Whereas such air pollutants and greenhouse gases are not emitted when using nuclear energy, long-lived radioactive waste is produced in the normal operation mode of nuclear power plants. Radioactive contamination (e.g. by the spent nuclear fuels and parts of the reactor) constitutes a threat to ecosystems as radionuclides are carcinogenic. The produced nuclear waste has to be securely stored for thousands of years to avoid exposure to radionuclides.

The use of renewable energies also has some environmental effects, which seem to be of minor importance compared to those of fossil fuels and nuclear energy. Nevertheless, the installation of renewables, like hydropower plants, wind power plants, biomass power plants, solar thermal power plants and ground-mounted PV might lead to negative impacts on the natural landscapes (visual impact) and the use of land and water.[9] Besides the indirect emissions from the construction, hydropower plants may result in problems concerning fish migration and the ecosystems located on both sides of the dams (cf. Kaltschmitt and Jorde 2007, pp. 378–383). Wind power plants produce emissions of infrasonic noise and can be a threat to birds and bats (cf. Kaltschmitt et al. 2007, pp. 343–348).

In contrast, the following sections will focus on emissions and environmental impacts caused by burning fossil fuels and appropriate emission reduction technologies.

6.2.2.1 Emissions from Burning Fossil Fuels

The use of fossil fuels is inevitably linked to oxidation of carbon and accordingly to the emission of the greenhouse gas carbon dioxide (CO_2). However, the **CO_2 emission factors** of different fossil fuels differ. Even within the same fuel, substantial variations may arise depending on the fuel provenance and variety. In Fig. 6.7, some average CO_2 emission factors in kg CO_2 per kWh energy content are shown for different fossil fuels (cf. Juhrich 2016, pp. 45–47). The different emission factors already illustrate that switching to fuels with lower CO_2 emission factors or even without any CO_2 emissions (e.g. renewables) can be a promising CO_2 reduction strategy. Yet, in addition to the fuel-specific emission factor, the efficiency of the corresponding production process has to be considered when

[9] Besides, regional effects on climate are known (e.g. due to local reduction of wind speeds), while global impacts are not (yet) identified.

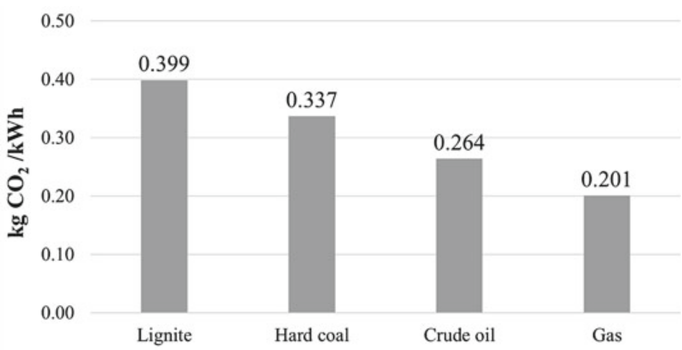


Fig. 6.7 CO_2 emission factors of different fossil fuels. *Source* Own illustration based on data from Juhrich (2016, pp. 45–47)

determining the CO_2 reduction of such a fuel switch (see Sect. 4.3). The average CO_2 emission factor of electricity produced in Germany in 2018 was about 0.474 kg CO_2 per kilowatt-hour electricity produced (kWh_{el}) compared to 0.764 kg CO_2/kWh_{el} in 1990 (cf. Icha et al. 2019). The emission factor of the electricity mix has been declining in Germany for many years due to measures like fuel switching and increasing efficiencies. In this context, it has to be mentioned that the lower the emission factor of an electricity mix is, the fewer emissions are reduced by saving one kilowatt-hour of this electricity, or in other words, the higher the specific CO_2 reduction costs of energy-saving measures (in €/t CO_2) are.

Besides the formation of CO_2 and hydrogen (see Sect. 4.1), also other chemical reactions take place during the combustion of fossil fuels, which result in emissions of air pollutants. The combustion of fossil fuels that contain sulphur leads to the formation of sulphur dioxide (SO_2), which might be oxidised to SO_3:

$$S + O_2 \rightarrow SO_2.$$

In addition, **oxides of nitrogen** (general formula NO_x) arise due to different sources of nitrogen (N) and different NO formation mechanisms. Besides fuel NO and thermal NO emissions, so-called prompt NO emissions can be distinguished. Thermal NO is produced from N_2 of the combustion air when reaction temperatures of about 1300 °C are reached; besides the temperature in the reaction zone also the air ratio and the residence time in the reaction zone have a strong influence on the NO formation (cf. Baumbach 1990, pp. 31–35). The fuel NO results from the nitrogen of the fuels, whereas the prompt NO emissions are produced through incomplete combustion (cf. Tan 2014, pp. 211–216). In a simplified way, the share of the different NO building mechanisms in total NO_2 emissions is shown in Fig. 6.8.

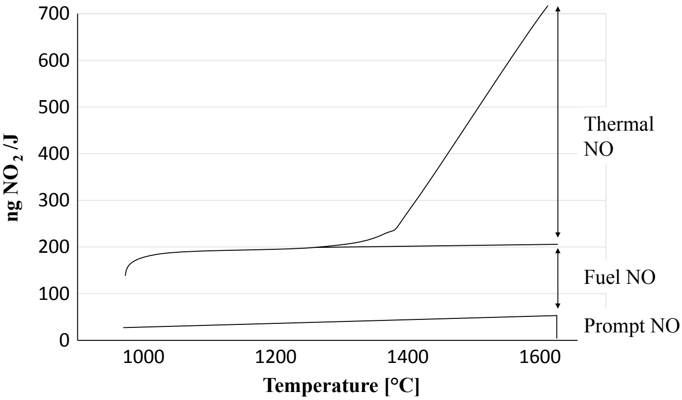


Fig. 6.8 Prompt NO, fuel NO and thermal NO depending on the temperature. *Source* Own illustration based on Hupa et al. (1989, p. 1497)

NO is oxidised to nitrogen oxide according to the following reactions:

$$NO + {}^{1}\!/_{2}O_2 \rightarrow NO_2.$$

Furthermore, trace elements like mercury may be emitted from combustion processes depending on the composition of the fuels via boiler ash and fly ash. Also, particulates [or particulate matter (PM)] are relevant pollutants. These are small solid or liquid particles, which can be considered as dust. Particulates are differentiated according to their diameters, e.g. PM_{10} comprise particles with a diameter of less than or equal to 10 µm, $PM_{2.5}$ accordingly with less than or equal to 2.5 µm.

6.2.2.2 Environmental Impacts

Emissions from burning fossil fuels can lead to different environmental problems and threats to human health. In the 1970s and 1980s, acid rain as a consequence of NO_x and SO_x emissions was the central ecological problem in many parts of the world. This has changed entirely, and nowadays, limiting climate change is on the top of the environmental agenda. Whereas the emissions of NO_x and SO_x have been reduced in many countries within the last 40 years due to the regulation put into place (see Sects. 2.3 and 6.2.3.1) and the emission reduction technologies needed for compliance (see Sect. 6.2.2.3), the worldwide emissions of the most important greenhouse gas carbon dioxide (CO_2) are still increasing (see Sect. 2.3).

Climate change is at least partly caused by human activities[10] (a comprehensive glossary presenting important terminology in the field of climate change can be found in Matthews 2018). Anthropogenic (i.e. human-made) emissions lead to a shift in the composition of gases in the atmosphere and thus form the so-called

[10] Natural activities causing changes of the climate are, e.g., variations of solar cycles.

anthropogenic greenhouse effect. Concerning emission quantities and impact, CO_2 is seen to be the most important greenhouse gas, yet there is a variety of greenhouse gases (GHG), including methane (CH_4), nitrous oxide (N_2O) and fluorinated gases. Greenhouse gases trap heat in the atmosphere. This leads to an intensification of the natural greenhouse effect and an increasing global mean surface temperature, so-called **global warming** – an essential part of climate change. The impacts of climate change may be different for different regions. Still, it is to be feared that in general climate change may lead to more extreme weather events (e.g. drought), rising sea levels, melting of the Arctic ice etc. (cf. e.g. Hoegh-Guldberg et al. 2018). According to the Intergovernmental Panel on Climate Change (IPCC), the anthropogenic temperature increase had already in 2017 reached about 1 °C compared to the pre-industrial level. However, it is essential to note that land regions suffer from even greater warming than the global average (cf. Allen et al. 2018, pp. 56–62). In this context, it has to be mentioned that the climate also changed in the past, but the current changes are much faster than what the earth has witnessed up to now, making it much more difficult for ecosystems to adapt to the new circumstances.

The effect of greenhouse gas emissions on climate change mainly depends on the following two properties of the corresponding gases (cf. Ardone 1999, pp. 85–90): the atmospheric lifetime, which is the residence time in the atmosphere, and the so-called radiative forcing, which is the ability of the gas to absorb infrared radiation. To compare the effects of different gases on the climate and to translate GHG emissions into carbon dioxide equivalents (CO_2-eq.), so-called **global warming potential** (**GWP**) factors of greenhouse gases over a given period are calculated relative to that of CO_2 (GWP factors of CO_2 are set to 1 for all considered periods) (cf. Forster et al. 2007, pp. 210–216):

$$\mathrm{GWP}_i = \frac{\int_0^T (\Delta F_i \cdot [\gamma_i(t)])\mathrm{d}t}{\int_0^T \left(\Delta F_{\mathrm{CO_2}} \cdot [\gamma_{\mathrm{CO_2}}(t)]\right)\mathrm{d}t} \tag{6.14}$$

with

i	Greenhouse gas
ΔF_i	Radiative forcing of the greenhouse gas i
$[\gamma_i(t)]$	Time-dependent abundance of the greenhouse gas i at time t based on a 1 kg initial emission impulse
T	Time period (e.g. 100 years) considered for the calculation of the GWP.

Using GWP factors makes it impossible to develop a greenhouse gas reduction strategy with the objective to reduce the concentration of these gases in the atmosphere during specific years, e.g. during the years with the maximum effect on the climate, within a given period. GWP factors cannot be clearly interpreted; a high GWP factor may result from a greenhouse gas having a low radiative forcing but a long residence time in the atmosphere or from a greenhouse gas having a high

Table 6.5 GWP factors of different greenhouse gases

	(Average) Lifetime (years)	Cumulative forcing over 20 years	Cumulative forcing over 100 years
CO_2	No single lifetime can be given	1	1
CH_4	12.4	84	28
N_2O	121.0	264	265

Source IPCC (2014, p. 87)

radiative forcing but a short residence time in the atmosphere (cf. Ardone 1999, pp. 86–87). Although the calculation of GWP factors inevitably results in some loss of information, these factors are often used to develop strategies to reduce greenhouse gas emissions as they are relatively easy to compute and handle. Table 6.5 shows the GWP factors of carbon dioxide, methane and nitrous oxide for periods of 20 (GWP_{20}) and of 100 years (GWP_{100}) (cf. IPCC 2014, p. 87).

Acid depositions are a consequence of emissions of NO_x and SO_x, which are converted in the atmosphere via nitrous acid (HNO_2) and sulphurous acid (H_2SO_3) into nitric acid (HNO_3) and sulfuric acid (H_2SO_4). Acid depositions are also called acid rains and have a pH below 5.0 on the pH scale for measuring the acidity, going from zero to 14. These depositions influence forests (forest dieback), waters and soils in many different ways due to acidification.

NO_x emissions (together with phosphorus emissions) furthermore contribute to so-called nutrient contamination. This eutrophication effect might, at first glance, seem to be somewhat positive. Still, it has many negative aspects as it can lead, e.g., to an extreme growth of algae in waters with undesired consequences like oxygen depletion and nitrate enrichment in soils and (drinking) groundwater. Furthermore, under sunlight, NO_x emissions and VOC emissions are starting substances for ozone formation (photochemical ozone or "summer smog").

Similar to the procedure to compare the climate effects of different greenhouse gases with the help of GWP factors, also various pollutants can be integrated into the calculation of their potential for acidification (acidification potential, AP), for eutrophication (eutrophication potential, EP) and for photochemical ozone creation (photochemical ozone creation potential, POCP).

Emissions of trace elements like mercury (Hg) and particulate matter can directly impact human beings causing severe health problems. Particulate matter might get into organs or even the bloodstream of human beings, and mercury is toxic to the human nervous system.

Besides the mentioned air emissions, the combustion of fossil fuels leads to ashes and sludge, which have to be disposed of depending on their components. Furthermore, thermal power plants need cooling, leading to emissions of heat, e.g. to adjacent rivers. Finally, the various kinds of electricity production result in different visual and noise impacts.

Air pollutants can be transported over long distances (long-range transmission), resulting in so-called **immissions** and subsequent impacts on human beings and the environment far away from the point of origin of the emissions. During the transportation phase, the produced emissions might be degraded or converted to

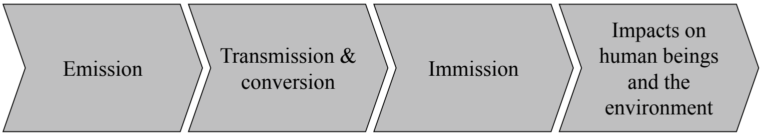


Fig. 6.9 Emission impact pathways

other substances (so-called secondary pollutants). These new substances will be deposited either with the help of atmospheric water (wet deposition) or as gases and particles (dry deposition).

To what extent emissions cause damages via immissions depends on different factors like the concentration rate. Calculations of the environmental and economic consequences are extremely challenging due to massive uncertainties as the whole pathway from the formation of the emissions to the resulting damages has to be considered (see Fig. 6.9 and e.g. ExternE 2018).

As emissions of air pollutants in one country can lead to immissions in another country, international cooperation is needed to identify where emissions should be reduced considering air dispersion (t_{ij}) from one region to other regions. Such an approach has been realised in Europe to find the cost-minimal strategy not to exceed the so-called critical loads, which can be interpreted as upper load limits. This has been implemented using the integrated assessment model Regional Air Pollution INformation and Simulation (RAINS), which can be expressed as a cost minimisation problem (6.15)–(6.17) (cf. e.g. Alcamo et al. 1990):

Objective function

$$\min \sum_c c_c \cdot v_c \cdot \xi_c \tag{6.15}$$

subject to the following restrictions

$$\sum_c v_c (1 - \xi_c) t_{cr} \leq \Gamma_r \quad \forall r \tag{6.16}$$

$$0 \leq \xi_c \leq 1 \quad \forall c \tag{6.17}$$

with

c	country index
c_c	per-unit emission reduction costs
v_c	emissions in country c
ξ_c	emission reduction rate
r	region [e.g. 50 × 50 km]
t_{cr}	transfer coefficient
Γ_r	critical load in region r.

Already this simplified model description illustrates that a lot of input data is necessary – like critical loads, transfer coefficients, emission inventories and cost functions – to calculate the optimal reduction rates for air pollutants. Furthermore, appropriate incentive structures have to be put in place to realise this cost-minimal solution. Otherwise, it might lead to a financial burden for countries not partaking in the benefits of the realised emission reduction.

6.2.2.3 Emission Reduction Technologies

An efficient emission reduction strategy may not only make use of specific emission reduction technologies but also aim at avoiding emissions by a reduction of the consumption of the related energy services or the use of more sustainable production routes (see Sect. 2.4). Emission reduction technologies in the narrower sense can be differentiated according to the location where the pollution reduction takes place into primary measures (pre-combustion and in-combustion technologies) and secondary measures (post-combustion technologies) (cf. Tan 2014, p. 18). With the help of pre-combustion technologies, the input of a combustion process is cleaned from substances inducing pollutions even before the fuel is used in the combustion process. If the firing technology itself is adjusted to reduce the formation of pollutants, the related technologies are called in-combustion technologies. In contrast to these two types of reduction technologies, secondary measures, also called **post-combustion** or **end-of-pipe technologies**, are used after the pollutants have been produced and released into the exhaust gas, which then is cleaned with the help of these technologies. To reach the required emission reduction level, even combining some of these technologies may be necessary.

In electricity production, pre-combustion technologies are of minor relevance compared to the other reduction technologies. One example of a pre-combustion technology is the desulfurisation of the fuel. Since many gas fields produce sour gases, the so-called gas sweetening by scrubbers using amine solutions is applied to remove sulphur compounds of natural gas. Furthermore, the **pre-combustion carbon capture technology** could be used to mitigate CO_2 emissions in the future. This technology is based on the **IGCC – internal gasification combined cycle** – process. A gasification stage is thereby inserted upstream of the gas turbine to generate a synthesis gas (see Sect. 4.1). This synthesis gas mainly consists of hydrogen and carbon dioxide, so that in a following step CO_2 can be separated.

In conventional power plants, in-combustion and post-combustion technologies are dominating. Developments to increase the efficiency of energy conversion processes can be counted among **in-combustion technologies**. By increasing the efficiency of technologies using fossil fuels to produce electricity, less input is needed and accordingly, fewer emissions, e.g. CO_2 emissions, are generated for producing the same output. Furthermore, in-combustion technologies are mainly used for NO_x reduction because the NO production strongly depends on combustion temperatures, the air ratio, and the residence time in the reaction zone, which modifications of the combustion process can influence. This already shows that there can be conflicting effects regarding different emissions; lowering the combustion temperatures might help reduce NO_x emissions (notably thermal NO_x), but can lead to lower efficiency and accordingly to higher CO_2 emissions.

Technologies to reduce the formation of NO_x comprise, amongst others, air staging, fuel staging and flue gas recirculation (cf. e.g. Tan 2014, pp. 268–272; Baumbach 1990, pp. 341–347). As the NO production depends on the air ratio, a principle to reduce NO production is the limitation of the oxygen available in the central reaction zone. With the help of air staging technologies, the combustion zone is divided into different zones: a fuel-rich zone, where only a part of the needed air (and therefore oxygen) is supplied, and a fuel-lean zone, where the rest of the required air is provided. Besides the staging of the air, there is also the possibility that the fuel is staged. This fuel staging or reburning technology is also characterised by different zones. Here three different combustion zones exist: a primary zone with a primary fuel used under fuel-lean conditions, a secondary zone with a secondary fuel used under fuel-rich conditions, and a fuel-lean final combustion zone. In the secondary zone, also called reburn zone, parts of the NO_x emissions already produced in the primary zone are reduced again. Another primary reduction technology is the recirculation of the flue gas into the combustion area, which can help to reduce NO_x emissions by lowering the combustion temperature. These three technologies, staging of the air, staging of the fuel and recirculation of the flue gas, and their combinations are used in so-called low-NO_x burners and may lead to a reduction of NO_x up to 70% (cf. Baumbach 1990, p. 347).

The so-called **oxy-fuel process** may be considered an in-combustion solution to mitigate CO_2 emissions (cf. Tan 2014, pp. 358–360). An air separation unit is needed for this process because not air but oxygen is used in the firing process. The resulting flue gas mainly consists of the two products H_2O and CO_2, which can be separated in a final step.

Post-combustion technologies are widely used to remove pollution emissions – e.g. SO_2, NO_x, particulates (cf. Tan 2014, pp. 277–313). For capturing particulate matters besides cyclones, filters and electrostatic precipitation (ESP) are used. In electrostatic precipitation, the particles are charged electrostatically and then deposited on a collecting electrode, from where they have to be removed, e.g. with the help of mechanical vibration. The separation efficiency of ESP is above 95% (cf. Baumbach 1990, p. 336). An alternative to an ESP with a relatively similar separation efficiency (cf. Tan 2014, p. 281) is the use of filters, like bag-house filters.

Flue gas **desulfurisation** (FGD) technologies are widely applied to remove SO_x emissions ($DeSO_x$) from the flue gas of power plants. The dominating version is the wet FGD, where typically limestone, i.e. calcium carbonate ($CaCO_3$), is used to produce calcium sulphate dehydrate ($CaSO_4 \cdot 2H_2O$) and CO_2[11] by capturing SO_x according to the following reactions (cf. Khartchenko 1997, p. 120):

[11] Again a conflicting effect is observable here: SO_2 reduction via limestone scrubbing leads to an increase of CO_2 emissions.

$$SO_2 + {}^1/_2O_2 \rightarrow SO_3$$
$$CaCO_3 + H_2O \rightarrow Ca(OH)_2 + CO_2$$
$$Ca(OH)_2 + SO_3 + H_2O \rightarrow CaSO_4 \cdot 2H_2O.$$

Calcium sulphate dehydrates, better known as gypsum, is the final product of FGD with limestone. This process is characterised by a colossal absorption tower, in which the flue gas is fed in and sprayed with the limestone suspension. The resulting separation efficiencies lie above 95% (cf. Baumbach 1990, p. 376). It is also possible to use other inputs as, e.g., magnesium hydroxide instead of limestone.

Concerning the reduction of NO_x emissions ($DeNO_x$) by using end-of-pipe technologies, the selective catalytic reduction (SCR) process is widely spread, but also the selective non-catalytic reduction (SNCR) can often be found in industry. The main difference between these two technologies is the existence of a catalyst in the case of SCR making this technology more expensive than SNCR, but also leading to higher separation efficiencies of above 95% (cf. Tan 2014, p. 295). Typically, ammonia (NH_3) is used as input for this process leading to the following main reaction at the catalyst:

$$NH_3 + NO \rightarrow N_2 + H_2O.$$

These post-combustion technologies also help reduce the emissions of trace elements like mercury, for which often no specific reduction measures have been installed.

Figure 6.10 shows three possible arrangements of the different **end-of-pipe technologies** in a hard coal power plant: high-dust, low-dust and tail end. From a thermodynamic point of view, the high-dust arrangement is preferable, as the SCR needs rather high temperatures of more than 300 °C to be operated.

In future, these three post-combustion technologies could eventually be supplemented by a fourth end-of-pipe technology to remove CO_2 from the exhaust gas and store it underground to prevent its contribution to the greenhouse effect (**carbon capture and storage**, **CCS**). Up to now, this concept has been realised in some industrial large-scale demonstration projects. In this post-combustion process, CO_2 is separated from the exhaust gas by a solvent, e.g. an amine solution. Compared to the other processes to capture carbon, i.e. the IGCC process and the oxy-fuel process, one advantage of this technology is that existing power plants can be upgraded with this post-combustion technology. An essential prerequisite for such an upgrading is that enough space at the respective site is available. In the context of CCS technologies, it has to be mentioned that the CO_2 captured has to be transported and stored safely. This could be realised by pipelines from combustion installations to deep underground storage possibilities. In the case of injecting CO_2 into (partly depleted) oil and gas fields, this can even help increase the field's output (so-called enhanced hydrocarbon recovery[12]). One should note that there are

[12] Especially enhanced oil recovery (EOR) and enhanced gas recovery (EGR).

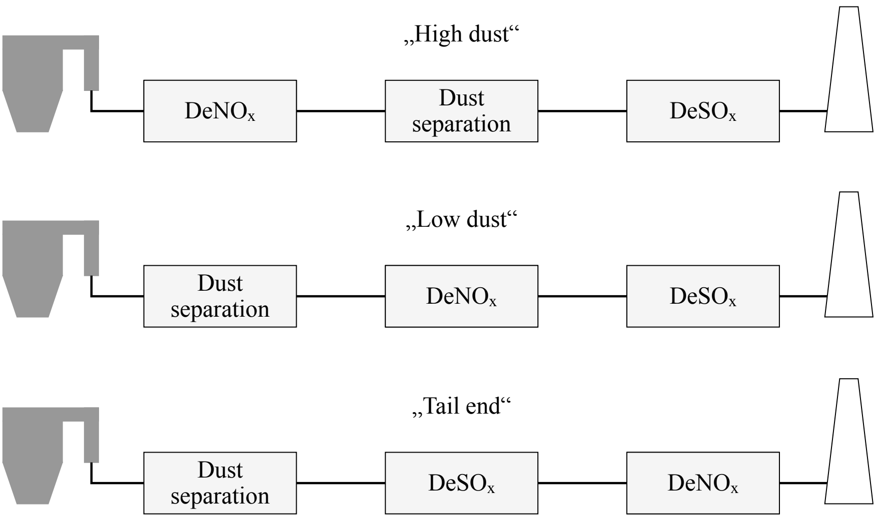


Fig. 6.10 Arrangements of the three end-of-pipe technologies DeNO$_x$, dust removal and DeSO$_x$. *Source* Own illustration based on Richers and Günther (2014, p. 38)

also limits to separation efficiency for CCS technologies, depending on the technology the attainable maximum is between 80 and 98% (cf. Mathieu 2010). Additionally, the energy conversion efficiency is reduced.

In the context of reducing the CO_2 concentration in the atmosphere, installations using bioenergy combined with CCS (BECCS) are an interesting option, as the plants take CO_2 out of the atmosphere during the period of growth and in the utilisation phase no CO_2 is released into the atmosphere (so-called negative emissions[13]). An alternative to storing the captured CO_2 in underground storage could be to use it as an input for the production of chemicals (**carbon capture and utilisation**, **CCU**).

6.2.2.4 Excursus: Life Cycle Assessment

When calculating the environmental impact of a product, a service, a technology or even an entire system (in the following just called “object under consideration”), the whole life cycle of the object under consideration should be considered. This comprehensive approach is often referred to as **life cycle assessment** (**LCA**), eco-balancing or cradle-to-grave[14] analysis. According to the standards of the International Organization for Standardization (ISO) (cf. ISO14040 2006; ISO14044 2006), an LCA consists of the four phases “Goal and scope definition”, “Inventory analysis”, “Impact assessment” and “Interpretation” (see Fig. 6.11). These phases do not have to be executed in a purely sequential way, rather it is

[13] Another possibility to produce negative emissions is the use of direct air capture (DAC).
[14] Only parts of the whole life cycle are considered in so-called cradle-to-gate or gate-to-gate analyses.

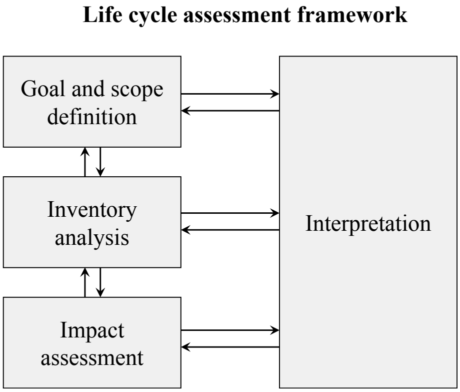


Fig. 6.11 Phases of an LCA according to ISO14040 (2006)

possible to jump back and forth between these stages to realise adjustments (cf. e.g. Matthews et al. 2014, p. 84).

In the first phase, framework conditions have to be defined, like the study's objective, the system boundaries and the so-called functional unit. The functional unit is needed to quantitatively describe the function of the object under consideration; so, if the environmental impacts of a technology for electricity generation are to be analysed, an appropriate functional unit (for the function electricity production) would be one kilowatt-hour of electricity produced (cf. Turconi 2014, pp. 5 and 11).

Based on these definitions, all the energy and material flows caused by the object under consideration, in other words all the inputs and outputs, are collected in the inventory phase; in the example of assessing an electricity generation technology, this would comprise data from the process of manufacturing the electricity generation technology via the emissions during the electricity production process up to the dismantling of the generation technology.

In the assessment process (third phase), the environmental impacts caused by the collected inputs and outputs of the object under consideration are analysed. This impact assessment phase consists of the three mandatory elements *selection*, *classification* and *characterisation* and further optional elements (cf. Matthews et al. 2014, pp. 366–396). First, the considered impact categories (e.g. global warming), indicators for these categories (e.g. radiative forcing over a given period) and characterisation models [e.g. concept of global warming potential (GWP)] have to be selected. Then the inputs and outputs connected to the object under consideration are linked to one or more of these impact categories, which is called classification. In the characterisation stage, characterisation factors (sometimes also called equivalence factors) resulting from the chosen characterisation model (e.g. GWP factors of the different greenhouse gases) are used to calculate the indicators. In addition, the ISO framework for LCA also allows for further optional elements, like the weighting to transfer the results for the different impact indicators into one value, showing the total impact of the object under consideration. The element of weighting is not mandatory as in many cases it might be extremely challenging (and subjective) to develop the needed weighting factors since the different impacts can hardly be compared; e.g. which weighting factors should be used to add up the impact categories of Global Warming and acidification? Finally, the results of the previous phases are discussed and recommendations are made.

6.2.3 Policy Instruments

6.2.3.1 First-Best and Second-Best Instruments

Negative externalities materialise if **property rights** are not applicable. Producing emissions and emitting them into the atmosphere leads to external costs if the costs caused by the damages resulting from these emissions are not reflected in the market prices. Then the producers of these emissions have no incentive to reduce them. However, there will be damages caused by environmental problems resulting from these emissions. Therefore, there is a need to address this market failure by implementing some policy instrument.

In an economic perspective, a straightforward solution is to establish property rights and create markets, an idea going back to Coase (1960). Coase showed that without the consideration of transaction costs and under further idealising assumptions, the allocation of property rights would lead to a bargaining process resulting in a solution, which is **Pareto efficient** (see Sect. 6.1). This so-called efficiency theorem implies that in the bargain outcome the marginal abatement costs of the polluters are equal to the marginal damage costs (see Sect. 6.2.1). The solution will be Pareto efficient, independently of the original allocation of property rights; however, the allocation of property rights will result in distributional effects. So an efficient outcome is possible, even if property rights are given to the polluters and not to the damaged third parties. And such a solution could even emerge without government intervention – through the willingness of the damaged parties to pay for pollution reduction. Yet this is a rather theoretical result since it is only valid in the absence of transaction costs.[15] In real-world problems, bargaining is likely to be difficult and costly if many polluters and damaged third parties are involved. Hence, a pure bargaining solution is, if at all, only practical for small-scale problems with only a few involved parties.

Yet in the same theoretical vein of mainstream environmental economics, two other welfare-optimal **first-best instruments** exist: the **Pigou tax** approach, also called Pigouvian tax and the first-best emissions trading approach.[16] Arthur Pigou developed the idea to shift the private cost curve up by increasing the costs with the help of a tax (Pigou 1920). This tax corresponds to t^* in Fig. 6.5. With the help of

[15] Note that transaction costs is used in the broad economic sense of costs related to a market transaction. These include here among others the cost for negotiating an agreement, for measuring pollution quantities and for enforcing the pollution limits.

[16] In principle such a trading approach can be used for all kinds of environmental goods, e.g. for land use (cf. Walz et al. 2009).

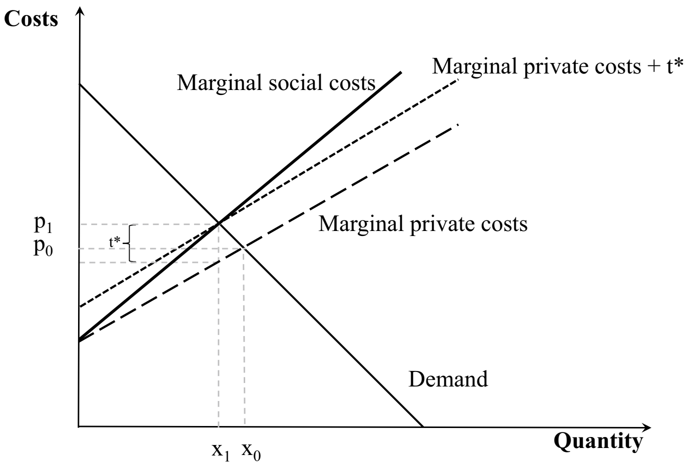


Fig. 6.12 Pigouvian tax shifting the marginal private cost curve. *Source* Own illustration based on Fritsch (2018, p. 113)

this tax, the marginal private cost curve (including the tax) intersects with the demand curve just in the point where the marginal social cost curve demand of the product intersects with the demand curve (see Fig. 6.12).

In the first-best **emissions trading** approach, a maximum limit for the total emissions being allowed is set – the so-called cap, which corresponds to *e** in Fig. 6.5. This cap is then broken down into emission allowances, with each allowance representing the right to produce the corresponding amount of emissions, e.g. one tonne of CO_2. Emission allowances can be traded. That is why this system is also called a "**cap and trade system**" (cf. Dales 1968).

The tax and the emissions trading approach are somewhat symmetric: Using a tax solution leaves the emission reduction to the market by setting a price, whereas in a trading solution, the emissions level is fixed and the price is left to the market (cf. Feess and Seeliger 2013, p. 119). But these two strategies for internalisation face challenges in practice related to information deficits: the government has to know the marginal emission reduction costs of all polluters as well as the marginal damage costs to determine the optimal control parameters of the respective instrument: the tax level (t^* in Fig. 6.5) in the case of the Pigou tax approach or the maximum of emissions allowed (e^* in Fig. 6.5) in the case of the first-best emissions trading approach.

Different policy instruments have been developed besides the non-economic idea to appeal to the emitters' sense of moral behaviour. These are frequently labelled as **second-best** solutions, since they are less efficient than the first-best solutions under idealised textbook conditions. For instance, the government might set an environmental target exogenously and identify a set of command and control measures to meet this target. The following major criteria may be used to assess second-best instruments for a given environmental problem:

- **target achievement/environmental effectiveness**: Will it be assured that the exogenously given environmental target is reached with the policy instrument at hand?
- **cost efficiency/static efficiency**: Will the exogenously given environmental target be reached at the lowest costs with the policy instrument at hand?
- **dynamic efficiency**: Will the policy instrument at hand set incentives to develop new technologies to minimise long-term costs?

Furthermore, criteria like political acceptability, practicability, distributional effects, social acceptance and adjustability (cf. e.g. Fais 2015, pp. 9–10) are relevant in the selection process.

Regarding the possible environmental policy instruments (cf. e.g. Perman et al. 2003, pp. 202–246; Cansier 1993, pp. 155–280), there is often a differentiation into four groups: Command and control instruments, economic incentive instruments, information instruments like information campaigns and voluntary instruments like voluntary agreements by the industry.

By using **command and control instruments**, the government directly intervenes in polluters' production processes. This can be realised using technology-based standards, with the help of which the permitted technologies are fixed; e.g. often only so-called Best Available Technologies (BAT) are postulated to be used. The other form of command and control instruments are performance-based standards, with the help of which emission limit values for a production process are fixed, but not the means by which these levels are to be reached. In Europe, the Industrial Emissions Directive (IED) sets different emission limit values for NO_x, SO_2 and dust emissions from large combustion plants. Upper limits for emissions from combustion units, which might be set in milligrammes per cubic metre of the flue gas (mg/m^3), can differ, e.g. depending on the size of the firing installation and the fuel used. Emission limit values have been one of the dominating policy instruments in the energy sector. They help to control emissions from individual installations and the corresponding emission reductions contribute to combat the related environmental problem, for instance, in the case of a regional ecological problem like acid rain. Yet, there is no guarantee that the total emissions, e.g. in a region, are capped by such an instrument. They might even increase if the number of used installations grows. But the main disadvantage of command and control instruments is that they will hardly lead to a cost-efficient solution, as the polluters do not have many options on how to comply with the given regulation. The company-specific situation is usually not considered, especially in technology-based standards. But also in the case of performance-based standards based on emission limit values, different marginal reduction costs across companies are not taken into account when all companies have to reach the same emission limit. In contrast, a cost-efficient policy instrument will lead to a situation where the marginal reduction costs of the companies involved are the same. This can be easily shown by using the Lagrangian method for the following optimisation problem (cf. e.g. Feess and Seeliger 2013, pp. 63–65):

Objective function

$$\min \sum_i C_i(\Xi_i) \tag{6.18}$$

subject to the following restriction

$$\sum_i \Xi_i \leq \Delta\Gamma \tag{6.19}$$

with

i company index
C_i absolute emission reduction costs
Ξ_i emission reduction
$\Delta\Gamma$ total emission reduction obligation.

For urgent environmental problems, like acid rain in the 1970s, emissions reduction obligations have been set at a very high level. In such a case, there are often very limited possibilities to fulfil the emission limit values, e.g. end-of-pipe technologies with separation efficiencies near to 100% have to be used to limit SO_2 emission values. So the economic drawback of command and control instruments is circumstantial.

Economic incentive instruments have as central idea to give incentives to polluters to change their behaviour. These instruments can be designed in-line with the **first-best instruments**, i.e. the Pigou tax, respectively, the emissions trading approach. To cope with the mentioned information deficits, the level of the tax – so-called price approach (cf. e.g. Baumol and Oates 1971) – or the allowed emissions – so-called quantity approach – is set administratively. Such a quantity approach clearly has to be distinguished from the theoretical first-best emissions trading approach based on the optimal emission cap. This may therefore be referred to as second-best emissions trading. The main advantage of economic incentive instruments is their cost efficiency. Each company is free to decide how to react: companies have to identify whether it is more favourable for them to reduce their emissions or to continue producing emissions and paying the tax or using emission allowances. All polluters will reduce their emissions until their marginal reduction costs are equal to the market price of the tradable emission allowances or the tax, so the marginal reduction costs of the different companies will be the same. As soon as the market price of the tradable emission allowances or the tax is below the individual marginal reduction costs, the polluter will choose to pay the market price of the emission allowances or the tax. One advantage of the second-best **emissions trading** approach compared to the **emission tax** is the environmental effectiveness: the exogenously given environmental target[17] in the form of the emission cap will

[17] It has to be mentioned here that in reality these targets are often the result of intense political negotiations.

be reached if efficient control mechanisms are established. In the case of a tax solution, this tax will probably have to be adjusted by the regulatory authority in a kind of trial-and-error procedure to converge to the envisaged environmental target.[18] Besides taxes and emission trading, there is also the possibility to incentivise polluters to change their behaviour by giving them subsidies. Subsidies can have the form of direct payments or investment grants, where the recipients get a fixed payment if they carry out a predefined action. Another form of incentivising market participants by subsidies is to put in place a price support mechanism, which enables the producers to get predefined prices for their goods (cf. Mechler et al. 2016).

Economic incentive instruments seem to be good solutions for the limitation of emissions causing global environmental problems. For such problems, the location where the emission reduction is realised is not decisive. On the other hand, these instruments could lead to regional hot spots with high immissions (cf. Feess and Seeliger 2013, p. 125), if all installations producing emissions that lead to immissions in this region decide not to reduce them – therefore, its application is not as straightforward if environmental damage is location-dependent. Emission trading schemes exist for different emissions: in 2005, an emission trading scheme was introduced to limit CO_2 emissions of European combustion installations, in the US emission trading schemes were realised even earlier, even for the reduction of emissions leading to regional environmental problems, as e.g. SO_2 [see, e.g., the Acid Rain Program (ARP)]. To avoid regional hot spots of environmental problems, the emission trading scheme was there supplemented by other regulations assuring local emission reduction.

6.2.3.2 The Implementation of Emissions Trading

To establish an emissions trading system, first, the system boundaries have to be set (e.g. the designation of the considered market players and emissions). As far as possible, limitations regarding participating sectors, countries, etc., should rather be avoided to have one comprehensive system. Another possibility to enlarge the system boundaries is linking existing emissions trading systems or integrating emission reductions realised in sectors not part of the trading scheme. Emission trading concepts can be designed for different target groups, the system might focus on either upstream players (e.g. entities placing emission-causing energy carriers on the market) or downstream players (e.g. producers of emissions). As soon as the system boundaries have been determined, a cap for the permitted total emissions has to be fixed administratively. In the next step, this cap has to be broken down into rights to produce a specified amount of emissions (so-called emission allowances). In SO_2 emissions trading, an emission allowance could, e.g., represent the right to produce one tonne of SO_2. These emission allowances are then allocated to the participating entities by using appropriate allocation mechanisms. This initial allocation can be realised by issuing the allowances free of charge according to the

[18] There is a broad discussion in environmental economics about the relative benefits of price- versus quantity-based instruments under uncertainty starting with Weitzman (1974).

emissions the company produced in a reference period in the past (so-called grandfathering), potentially multiplied by a particular reduction factor. This form of allocation might penalise companies that already invested in emission reduction measures resulting in lower emissions in the past and can – of course – not be applied for companies just entering the market. Another form of free of charge allocation is to use the emissions of a reference or benchmark process (e.g. of the BAT) and allocate the corresponding allowances to the used processes. Alternatively, emission allowances can be issued via auctions. The participants are subsequently free to trade the allocated emission allowances (e.g. via a secondary market). Furthermore, the involved companies have the responsibility to report their emissions. At the end of the compliance period, the participants finally have to deliver emission allowances equal to the emissions they produced during this period. Then the whole procedure starts again for the next compliance period. To control the compliance of the companies involved, a regulatory authority has to be established and an organisational and administrative effort is required. Within the emissions trading system, further flexibility mechanisms can be integrated: there might be the possibility to bank emission allowances to use them for compliance in later periods (so-called banking) or the option to use emission allowances that will be allocated in later compliance periods already in the current period (so-called borrowing) (cf. e.g. Flachsland et al. 2008, pp. 18–19).

Through emissions trading, a new factor of production arises in the participating companies,[19] which has to be integrated into production and investment planning processes. Depending on the cap level, this production factor might become scarce, leading to higher allowance prices on the market. An emission allowance represents a fundamental factor of production, which has at least one exceptional feature: as the participants are only obliged to deliver allowances at the end of the compliance period, this factor of production can be procured even after the production of the emissions for which it is used, in other words, the producer of emissions can go physically short (cf. Wallner et al. 2014, p. 18).

In line with the concept of opportunity costs, companies will price in a scarce production factor – independently of the chosen allocation mechanism,[20] as the company has the opportunity to use this factor of production in another way: the company could decide not to use it as an input for its own production process, but to sell it on the market. On the other hand, the allocation mechanism can lead to considerable distributional effects. Whereas free of charge allocation might help to create or sustain acceptance for the system, such an allocation may produce

[19] Factors of production are inputs needed to be able to produce the output of the company. In Economics usually the three factors of production land, capital and labor are differentiated, in Business Administration much more detailed classifications exist (cf. e.g. Dyckhoff and Spengler 2010, p. 16-19).

[20] This does not hold true for contingent allocation rules. A scarce production factor will not necessarily be fully priced in by a company if the allocation in future trading periods depends on the actions of the company still to be taken, e.g. if the reference period of a later allocation period is updated and incorporates the current year the production today might influence the allocation in future (cf. Weber and Vogel 2014).

additional profits (so-called windfall profits) as the involved companies might raise their product prices (in the power sector, the wholesale electricity prices) according to the economic value of this new factor of production. However, they do not have to pay for it. Alternatively, the auctioning of emission allowances will lead to revenue streams for the government.

6.2.4 Limiting Climate Change

One of the most important political achievements in combating climate change (see Sect. 6.2.2.2) is the **United Nations Framework Convention on Climate Change** (**UNFCCC**), which already entered into force in the year 1994. This convention has been operationalised by the so-called **Kyoto Protocol**, coming into force in 2005, and the so-called **Paris Agreement**, coming into force in 2016. Whereas the Kyoto Protocol set targets for the reduction of greenhouse gas emissions in industrialised countries for the commitment periods 2008–2012 and 2013–2020, according to the subsequent Paris Agreement all parties to this agreement have to present their contribution to the reduction of greenhouse gas emissions by the preparation of so-called nationally determined contributions (NDCs).

Countries have put in place different instruments to fulfil the objectives set by the Kyoto Protocol and the NDCs. This chapter will focus on two rather different ways to approach the greenhouse gas reduction targets, which both have been implemented: on the one hand, setting an emission reduction target, allocating the corresponding emission rights and allowing trading of emissions rights (Sect. 6.2.4.1), on the other hand, setting incentives for specific technologies, which do not or hardly lead to greenhouse gas emissions, by introducing support schemes only for them, e.g. feed-in tariffs for renewable energies (Sect. 6.2.4.2). Finally, in Sect. 6.2.4.3, possible interactions between these instruments, if they are used at the same time, will be discussed.

6.2.4.1 The EU Emissions Trading System (EU ETS)

In 2005, the **EU Emissions Trading System** (**EU ETS**) was launched in Europe[21] to limit CO_2 emissions of combustion installations with a thermal input exceeding 20 MW. Later, the system boundaries were expanded to integrate emissions of the greenhouse gases N_2O and perfluorocarbons (PFC) from specific industrial processes, which are converted into CO_2-equivalents by using GWP_{100} factors (see Sect. 6.2.2.2), as well as to emissions from the aviation sector.[22] About 45% of total EU greenhouse gas emissions, more than 11,000 installations in over 30 countries are covered by the EU ETS (cf. e.g. European Commission 2018).

[21] As the environmental problem that this emission trading system is aiming at is a global one, limitations regarding participating countries should rather be avoided.

[22] Temporarily the scope regarding the aviation sector was reduced to flights between airports in Europe.

As the European emissions trading scheme does not cover all the greenhouse gas emissions in Europe, emission reduction targets for the sectors not included in the EU ETS had to be put into place, which was done by setting national targets for each member state (Effort Sharing Regulation (ESR)[23]). The fact that European member states have, on the one hand, emission reduction obligations on a national level and that on the other hand combustion installations in these countries are participating in the EU ETS, leads to challenges concerning the breaking down of the national reduction targets to the different sectors, because under an emission trading scheme it is not clear in which installations the emission reduction will be realised.

The trading system started with a test period from 2005 to 2007, followed by the trading periods 2008–2012 (phase II) and 2013–2020 (phase III). The fourth trading period comprises the time horizon from 2021 to 2030. The emission allowances of the EU ETS are called EUAs (European Union Allowances) and represent the right to produce 1 tonne of CO_2-equivalents each. The given emission cap shrinks from year to year to reach the objectives to reduce the emissions from the participants (at the time of writing this book, the objective was 43% in 2030 compared to emission levels in 2005).

During the first two trading periods, the European countries had to develop so-called National Allocation Plans (NAPs), indicating how many emission allowances are issued in each country and according to which allocation mechanisms these allowances are distributed to the involved installations. According to these NAPs, most installations got the allowances free of charge, mainly based on benchmarks. This means that e.g. many power plants got the allowances according to a (fuel-specific) benchmark (kg CO_2/kWh), which had to be multiplied by a utilisation factor (full-load hours per year). This utilisation factor was calculated from historical data or had to be estimated by the plant operator or was set administratively by the government. In the third trading period, auctioning (using sealed bids and uniform pricing) has become the default allocation mechanism, but still industrial processes get (parts of) the allowances free of charge based on benchmarks. Especially companies that might relocate their production sites due to economic reasons into a country, where they do not have to undertake efforts to reduce their emissions, get their allowances free of charge, as such relocation could lead to even higher CO_2 emissions (so-called **carbon leakage**). Participants have to submit sufficient allowances by the end of April of the following year to cover their previous year's emissions. The system allows banking of the allowances. Only between phase I and phase II, emission allowances could not be banked because 2008–2012 was the commitment period under the Kyoto Protocol and the member states did not want to jeopardise the fulfilment of their emission reduction targets through the banking of allowances into this period. On the other hand, the EU ETS does in principle not allow borrowing. Effectively, borrowing is at least partially possible because at least parts of the yearly allocation process take place before the

[23] To fulfil the national targets, the ESR provides different flexibility mechanisms, e.g. it is allowed that member states buy "surplus emission reductions" from other member states.

allowances have to be surrendered to demonstrate compliance in the previous year. Other flexibility options are the possibility of generating emission credits by reducing emissions through projects in countries (international offsets) or even sectors (domestic offsets) not involved in emissions trading and using these credits for compliance within the emission trading scheme. Before the fourth phase of the EU ETS, it was allowed to at least partly exchange different kinds of these credits for EUAs: Certified Emission Reduction (CER) credits from projects that reduce emissions in developing countries [Clean Development Mechanism (CDM)], and Emission Reduction Unit (ERU) credits from projects in industrialised countries [Joint Implementation (JI)]. The credits are calculated by comparing the emission level in the situation with the emission reduction project to a hypothetical emission level of a business as usual (BAU) scenario; the project has to prove the so-called additionality of the emissions reduction, meaning that it must be shown that without the project the emission reduction would not have occurred. Therefore, this form of emissions reduction is called a **baseline and credit program**. As long as a greenhouse gas emission trading scheme does not cover all sectors and emissions worldwide, these credits provide an incentive to identify and use cheap emission reduction measures, which otherwise would not be exploited.

As the EU ETS fixes the overall cap of emissions for the participating sectors, additional political requirements for these sectors, e.g. national (domestic) decisions to phase out coal-based power generation or to introduce a carbon floor price, do only lead to an additional emission reduction, if the cap can be adjusted. Otherwise, the emission reduction in one country will be compensated by additional emissions in other countries [so-called waterbed effect (cf. Perino 2018)].

Since the beginning of emissions trading in Europe in 2005, the prices of EUAs have shown relatively high volatility. Already in the first phase, allowance prices exceeded 25 €/tCO_2-eq. and then fell back drastically, a development rather similar to what was observed in the second trading period. Trading phase III was characterised by rather low prices till 2017, and since then, a considerable increase can be seen (see Fig. 6.13).

Fig. 6.13 Development of EUA prices. *Sources* Own illustration based on data from ICIS and EEX

The collapse of prices in the trading period 2005–2007 was a consequence of false expectations followed by the discovery that allowances issued by member states were abundant, which led to a surplus in the market. As soon as this became clear, the prices of EUA dropped, resulting in a price of zero because banking was not allowed between phase I and phase II. Also, in the trading phase 2008–2012, the prices crashed due to a surplus of about 2 billion emission allowances in the market. The reasons for this surplus are manifold:

- the economic crisis in 2008, leading to a reduction in industrial production,
- the intense use of relatively cheap international offsets and
- interrelating policy instruments, like the support for renewable energy sources, leading to reduced demand for emission allowances (see Sect. 6.2.4.3).

Owing to this surplus, many allowances have been set aside by the market players to be used in future periods as they expect a scarcer market and banking is possible. The European Commission reacted to the price decline and the accumulation of banked allowances by taking emission allowances out of the market in the years 2014–2016 through the so-called backloading, and eventually deciding to put them into the so-called **market stability reserve** (**MSR**).

For trading phase IV, the yearly emission cap has been tightened considerably. Depending on the amount of allowances that are banked, further allowances will be put into the MSR, or rather allowances in the MSR will be returned into the market. In addition, an upper bound for allowances within the MSR has been introduced and all allowances in the MSR above this threshold will be cancelled, which has different effects on the EU ETS, e.g. eventually leading to an extra emission reduction of additional domestic emission reduction strategies (cf. Perino 2018, p. 263). Furthermore, countries are now allowed to cancel allowances in the EU ETS if they perform additional measures like a national coal exit. Hence, the effects of additional measures may go beyond a drop in demand for emission allowances and the corresponding allowance prices – although the operation rules for the market stability reserve may partly offset these effects.

When analysing the future allowance price development in the European ETS, it has to be considered that besides the market fundamentals, the participants' trading behaviour may impact EUA prices. As power companies sell their production at least partly on long-term future markets, they face the risk of a rise in costs of the needed factors of production, which they may want to hedge (see Chap. 8). Therefore, it seems rational to assume that power companies will buy the factors of production or futures or forwards for them (including emission allowances) at the time when they sell their electricity (cf. Wallner et al. 2014, p. 49).

Depending on the prices of the EUAs, there may be considerable impacts on the planning processes and operation decisions of the companies involved in the emissions trading scheme. Figure 6.14 illustrates the effects of the production factor *emission allowance* on production decisions of power companies, the subsequent merit order (see Sect. 4.4.1) and the related costs (CO_2 costs). It should be stressed once again that these effects are independent of the chosen allocation mechanism as

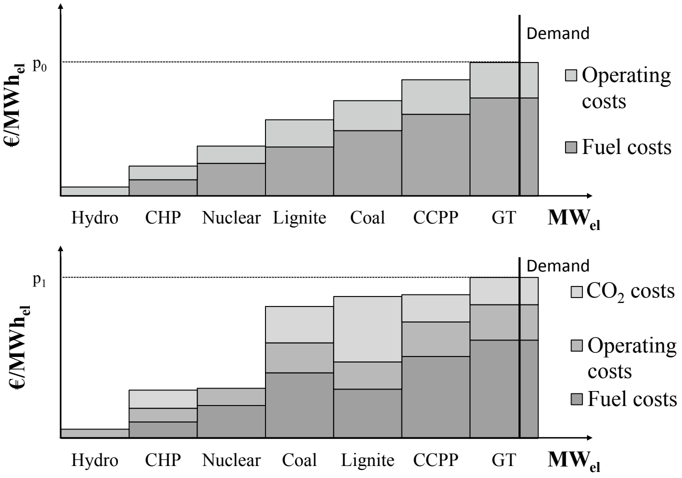


Fig. 6.14 Stylised merit-order curves and clearing prices with and without CO_2 emissions trading

the new production factor normally is priced in anyway. The wholesale electricity price increases by the CO_2 costs of the price-setting power plant from p_0 without emissions trading to p_1 with emissions trading. This illustration assumes that electricity demand is inelastic (see Sect. 3.1.4), which results in the vertical demand curve. Furthermore, in this illustration, the introduction of emissions trading leads to a change in the power plants' merit order (see also Sect. 7.1.1). Whereas the marginal costs of hard coal power plants are higher than the costs of lignite power plants without emissions trading, this changes under the assumed CO_2 costs: now the sum of all three variable cost items (fuel costs, operating costs and CO_2 costs) is higher for lignite power plants than for hard coal power plants (see lower part of Fig. 6.14).

The production factor *emission allowances* also influences power companies' investment planning (e.g. based on the net present value). With emissions trading, new cash flows occur: cash inflows change due to changed electricity prices, cash outflows change due to the purchase of emission allowances. Suppose emission allowances for new power plants are allocated free of charge (at least in some years of the installation's lifetime). In that case, this functions similar to an investment grant, stimulating new investments – but possibly also distorting the investment decisions (cf. Weber and Vogel 2014).

6.2.4.2 Renewable Support Schemes

A GHG emission trading system leads to incentives to invest in less greenhouse gas emitting technologies, such as renewable energies. Another possibility to increase the use of renewable energy sources for electricity production is to establish policy instruments that exclusively support these technologies. In addition to the incentives resulting directly from such a support scheme, renewable sources are often privileged by the priority connection of these installations and the priority purchase and transmission of the electricity produced in these units. Instruments to promote renewable energies can generally be differentiated into two basic clusters: those setting the remuneration for the technologies used (price-based instruments) and those setting the quantity of the technologies used (quantity-based instruments) (cf. e.g. Fais 2015; Held et al. 2014; Finon and Menanteau 2003). This is connected to some challenges in designing an appropriate support scheme for renewables: Should the instrument support the produced energy or the installed capacity? Should there be a different parameterization of the chosen instrument for different technologies or should the instrument be technology-neutral? To assess and compare different instruments to increase the use of renewable sources, evaluation criteria like efficiency and target achievement (see Sect. 6.2.3.1) may be used.

In the past, the price-based instrument of a **feed-in tariff** (**FIT**) was frequently used for increasing renewable electricity generation. Under this policy instrument, the producers of electricity from renewable energy sources are entitled to sell their green electricity to the (transmission) system operator and get a fixed payment, typically for each kilowatt-hour electricity produced or fed into the grid (e.g. in €ct/kWh$_{el}$). Typically, the level of the FITs depends on the technology and the year of installation, perhaps even on the weather conditions, like average wind speeds at the location concerned. The general idea of such specific FITs is that the remuneration payments are sufficient to cover the generation costs of the technology used. FITs are typically guaranteed for a fixed period of years. This instrument has been often used to accelerate the market introduction of a technology. On the one side, FITs lead to rather long-term price guarantees for the investor. On the other side, the instrument does not incentivise a real market integration. This is because the owner of a renewable energy installation does not have to care about the electricity market ("produce and forget") because the remuneration is fixed, totally independent of the market price. The electricity can be fed in whenever the unit is operating. The German Renewable Energy Sources Act (EEG) focussed for many years on this policy instrument, leading to a strong increase of renewable energy installations in Germany and a considerable reduction of the worldwide investment costs notably for PV systems at the expense of high additional costs for the German (non-privileged) electricity consumers due to the so-called EEG-levy.[24]

An extra incentive for increasing renewable electricity generation might exist if the electricity produced in decentralised units, e.g. rooftop PV, can be used to cover parts of the electricity demand of the so-called prosumer (self-consumption; see Sect. 10.7.4). Under a so-called **net metering** scheme the feed-in of electricity is subtracted from the amount of electricity obtained from the grid. In other words, the feed-in tariff has the same level as the respective electricity retail price. In contrast, there are systems that differentiate between the tariff a customer has to pay for electricity taken from the grid and the payment the customer gets for the feed-in of electricity produced in a decentralised production unit. A system with such a

[24] This renewable levy covers the gap between electricity wholesale market prices and the renumeration paid.

differentiation and the requirement that the whole electricity produced in the decentralised unit has to be fed in, in other words self-consumption is not allowed, is called **gross metering**.

A more market-oriented form of price-based instruments to foster renewable electricity production are **market premiums**, also called **feed-in premiums**. Here a premium is paid on top of the electricity wholesale price whenever operators of the renewable energy installation sell their electricity on the market. The operators must market their output. Therefore this instrument is also called direct marketing. So the renewable energy operator has different revenue streams: the wholesale electricity price and the premium. The premium can be determined in different ways: it can e.g. be fixed, variable (floating) or limited by a cap and floor (cf. Held et al. 2014, pp. 38–43). In the German market premium model the difference between the remuneration according to a fixed feed-in tariff and the monthly average electricity price at the exchange is offset with the help of a monthly market premium (see Fig. 6.15). This leads to an incentive to shift electricity production to hours with wholesale electricity prices above the monthly average and avoid production during hours with very negative electricity wholesale prices. If the electricity price at the market is higher than the fixed feed-in tariff, the operators of the renewable energy installations are allowed to keep this difference. This feature distinguishes this market premium mechanism from the instrument called "Contract for Difference (CFD)", where power generators have to pay back the positive difference between the market price and the feed-in tariff (also called the strike price; see Sect. 8.6).

An instrument that seems to have even higher compatibility with markets is a so-called quota obligation combined with a system to trade **green certificates**. Here a central institution sets a target concerning renewable energies, e.g. a minimum of MWh or a particular share of total electricity production that stems from a specific

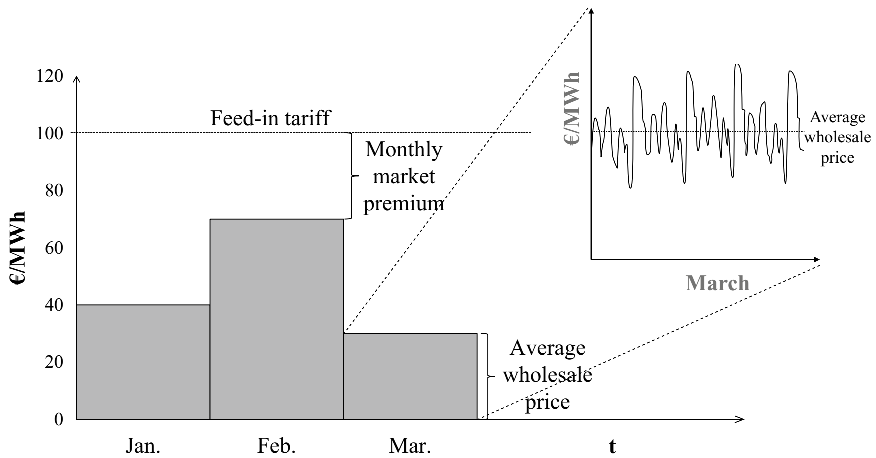


Fig. 6.15 Calculation of the monthly market premium in Germany

renewable energy technology or all renewable energy sources.[25] This quota then has to be fulfilled by each supplier of electricity. Therefore, the renewable electricity producers get certificates according to the number of MWh produced. These green certificates can be sold to suppliers (retailers), who use them to prove compliance with the required quota. Furthermore, certificates can be sold or bought via a secondary market, so the market determines the price for green certificates. This again leads to different revenue streams: besides the electricity market, a certificate market emerges, which might lead to new revenue streams, notably for companies having excess renewable certificates. In principle, it is also possible to install a quota obligation without the possibility for trading, yet this will typically lead to inefficient results since marginal procurement costs for renewables will not level out (see the argument on environmental command and control policies made in Sect. 6.2.3). The apparent advantage of this instrument of higher compatibility with markets might come at the expense of an additional risk premium producers of renewables are requiring due to the higher risk to recover their investments (cf. Haas et al. 2011).

A possibility to determine the financial support needed in a competitive way is the establishment of **procurement auctions** (for detailed information see IRENA and CEM 2015). To realise this, the government has to fix the additional electricity production in renewable energy installations or the capacity to be installed within a certain period and issue a call for tender. Depending on the governmental objectives, the auctions may be implemented as technology-neutral or technology-specific auctions. Pre-qualified market players are allowed to submit bids concerning the remuneration they need to realise their project. Finally, the auctioneer identifies the winning bids, normally the bids requiring the lowest financial support.

Often setting up one of these policy instruments is supplemented by additional instruments, such as tax exemptions, investment aids, information campaigns and low-interest loans (cf. Held et al. 2014, p. 82). Sometimes the market players want to avoid governmental interference and voluntarily agree to realise certain investment or production targets (so-called voluntary agreements).

Another strategy might be to take advantage of consumers' willingness to pay a surplus amount for electricity produced from renewable energy sources. This can be realised with the help of special tariffs (green tariffs), which ensure that the customers' electricity demand is (totally or at least to a certain percentage) covered by electricity from renewable energy sources. To prove that the consumed electricity stems from renewable energy sources, Guarantees of Origin (GoO) have been put in place.

For all financial support mechanisms, the financing of the difference between the remunerations paid to the producers of electricity from renewable energy sources and the electricity market prices has moreover to be decided. This could be done out of the general government budget or with the help of a levy, which electricity

[25] If the target with regard to renewable energies is given for all renewables together, the support scheme is called technology-neutral, which can lead to high profits for the producers of renewables if the renewable cost curve is rather steep (cf. e.g. Haas et al. 2011).

consumers have to pay via their retail price. In turn, such a levy leads to some distortions in competition, both between electricity and other energy carriers, and between domestic electricity users and international ones.

6.2.4.3 Interference Between Emission Trading and Renewable Support

In the energy sector, different political objectives exist, e.g. concerning environmental protection. Diverse policy instruments are sometimes put into place to reach these objectives, leading to a complex mix of instruments. Occasionally, different instruments are even deployed for one political objective. This seems to contradict the design rule, often referred to as the Tinbergen Rule: only one instrument should be used to reach one policy objective – in fact, Tinbergen stated that there have to be as many policy instruments as policy targets (cf. Tinbergen 1952).

With different instruments in place, interferences between them may occur. This is exemplarily shown subsequently for a (simplified) situation, where in a region (or a sector) first a CO_2 emissions trading system has been established and then a support scheme for renewable energies is introduced. In this setting, the support for renewable energies leads to more CO_2-free electricity produced in renewable energy units. But this does not necessarily lead to less CO_2 emissions in the region as the CO_2 emissions are limited by the fixed cap of the emissions trading system. This means that the reduction at one location within the system may induce increases at another site (see waterbed effect in Sect. 6.2.4.1). More electricity from renewable energy sources implies that less electricity has to be produced by other technologies, but the same number of emission allowances is still available (vertical line S in Fig. 6.16). In other words, the demand curve for allowances (line D) is shifted to the left by the emission avoidance E due to renewables and accordingly, the price for emission allowances decreases (see Fig. 6.16). At this point, it is to be

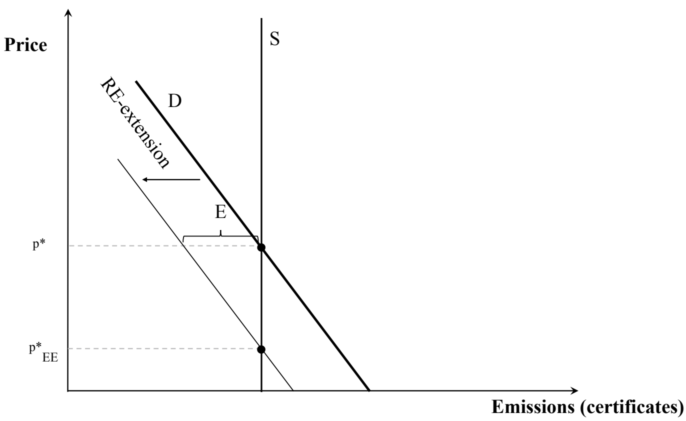


Fig. 6.16 Effects of renewable support schemes on an emissions trading scheme. *Source* Own illustration based on Marquardt (2016)

stressed that the same effect appears when a support scheme for other CO_2-free technologies (e.g. nuclear energy) or a phase-out for coal power plants is introduced in a region already having a CO_2 emissions trading system in place. Finally, it should be mentioned that to ensure that an additional CO_2 emission reduction is realised by introducing a support scheme for renewable energies in a system, which already has a CO_2 emissions trading scheme, the cap of the CO_2 emissions trading system has to be reduced as soon as the support scheme for renewable energies is put in place.

6.3 Further Reading

Varian, H. (2014). Intermediate Microeconomics. 9th edition. New York: W. W. Norton & Company, 2014.

This textbook gives an extensive overview of microeconomics, including case studies and examples.

Jamasb, T., & Pollitt, M. (2000). Benchmarking and regulation: international electricity experience. Utilities Policy, 9, 107–130.

This paper provides manifold information about incentive-based regulation and the used benchmarking methods.

Fritsch, M. (2018). Marktversagen und Wirtschaftspolitik – Mikroökonomische Grundlagen staatlichen Handelns. 10th edition. München: Vahlen.

The book Marktversagen und Wirtschaftspolitik provides a comprehensive presentation of different forms of market failure (e.g. due to external effects and market power) and possible countermeasures.

Perman, R., Ma, Y., McGilvray, J., & Common, M. (2003). Natural Resources and Environmental Economics. 3rd edition. Essex: Pearson Education Limited.

The book Natural Resources and Environmental Economics gives an extensive introduction into natural resources and environmental economics. In the context of power economics, especially the second part of the book dealing with environmental pollution is very relevant.

Tan, Z. (2014). Air Pollution and Greenhouse Gases – From Basic Concepts to Engineering Applications for Air Emission Control. Singapore: Springer.

In contrast to the other books mentioned in this section, the book Air Pollution and Greenhouse Gases provides a much more technical perspective. The book presents insights into combustion processes, emissions, and emission control.

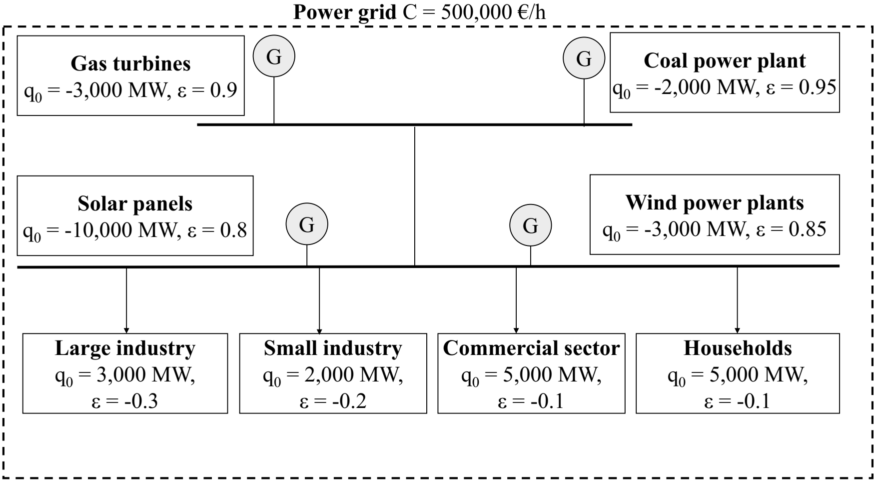
6.4 Self-check of Knowledge and Exercises

Self-check of Knowledge

1. What is meant by the technical term “subadditive costs”?
2. Distinguish between the different variants of unbundling.
3. Explain the differences between price cap regulation and revenue cap regulation.
4. Formulate the objective function and the restrictions of the RAINS-model.
5. The firing of which fossil fuels leads to which pollutants?
6. Name the CO_2 emission factors of the different fossil fuels.
7. Which NO formation mechanisms do you know?
8. Name two emission reduction technologies for CO_2, SO_x and NO_x.
9. Which criteria are used to assess environmental policy instruments?
10. Use these criteria to assess a CO_2 tax and a CO_2 emissions trading approach.
11. Compare feed-in tariffs for renewables with a quota obligation combined with a system to trade green certificates.
12. Why might it be difficult for a European country to fulfil its own CO_2-reduction target if energy-intensive companies from this country are included in the European ETS?

Exercise 6.1: Network Pricing

You are the owner of the illustrated power grid with total grid costs of 500,000 €/h on average (see the dimensioning capacities and the price elasticities in the figure). Which (uniform) grid fee would the market participants have to pay in the second-best solution (price equals average costs) if the price elasticities of all producers and consumers are not considered? How will this change if the given price elasticities are considered and the average wholesale price of 4 Cent/kWh is used as reference costs (please use the spreadsheet contained in the appendix to this book)?



Exercise 6.2: Emissions of Power Plants
Calculate the yearly emissions of CO_2, SO_2 and NO_x of a 750 MW hard coal power plant with 7500 full-load hours, an efficiency of 40% and the following emission factors: SO_2: 60 kg/TJ and NO_x: 50 kg/TJ.

Exercise 6.3: Effects of Emission Costs on Production and Investment Decisions
Your company plans to invest in a new CCGT. Calculate the yearly production costs (in €ct/kWh) using the techno-economic data regarding investment, O&M and fuel costs presented in Chap. 4, assuming 5,000 full-load hours, a CO_2 allowance price of 25 €/t and an interest rate of 10%. How would your bid in a competitive day-ahead market with a clearing price auction look like? How do these results change if the government introduces a free of charge allocation of emission allowances for the first 5 years of operation?

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