Markets for Solid Fuels and CO_2 Emissions 10

Solid fuels are hard coal, lignite, and firewood. Their common properties are low energy densities resulting in high cost of transportation which in turn limits competition in solid fuel markets. Thanks to reduced costs of coal extraction, productivity increases in maritime transport, and reduced public subsidies, a global market for hard coal has nevertheless developed.

Due to coal's high carbon content, coal combustion is the major source of global CO_2 emissions, amounting to about three tons of CO_2 per ton of hard coal. In addition, coal mining is associated with emission of methane (so-called pit gas), another important greenhouse gas. Thus the economics of coal markets cannot be discussed without referring to international efforts designed to reduce global emissions of CO_2 and other greenhouse gases. In an attempt to achieve this aim, the European Union created a market for CO_2emission allowances (EU Directive 2003/87/EC). Depending on the effectiveness of this system, CO_2 emissions may become sufficiently costly to increase the price of coal relative to that of other fuels, triggering its substitution by less harmful alternatives.

The issues addressed in this chapter are:

- What are the factors determining the development of the market for hard coal?
- What determines its price on the world market?
- Is the market for coal competitive?
- Is there a trend towards vertical integration as in the oil industry?
- What are the perspectives of solid biofuels and in particular wood as a substitute for coal?
- What determines the price of emission rights?
- How do these prices depend on the design of the market for emissions?

The variables used in this chapter are:

CDS Clean dark spread
DS Dark spread
Em Annual emissions [in tons of CO_2 equivalent]

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M	Inventory of greenhouse gases in the atmosphere
p_{CO2}	Price of a CO_2 emission right
p_{coal}	Coal price
p_{el}	Wholesale price of electricity
ω	Fuel efficiency

10.1 Solid Fuels and Their Technologies

Solid fuels comprise types of coal, lignite, wood, and biomass fuels which differ widely in terms of their properties. Coal with a carbon content below 55% of dry matter belongs to the category of lignite, whereas fuels with a carbon content between 55% and 65% are categorized as hard coal. Table 10.1 presents some properties of economically relevant solid fuels. Their water content ranges between 6% in hard coal and up to 65% in soft lignite. On the whole, it varies inversely with the energy content measured using the lower heating value. Accordingly, anthracite has the highest heating value of up to 37.7 MJ/kg but still falls short of liquid and gaseous fuels (see Tables 8.7 and 9.2). The heating values of lignite, firewood, and other biomass fuels are lower, causing them to have comparatively high transportation cost per energy unit.

In return, biomass fuels have the advantage that their combustion is not associated with a net emission of greenhouse gases. The CO_2 emissions released from burning firewood are compensated by the growth of trees and other biofuels. Assuming a constant global stock of biomass, these fuels are therefore neutral with respect to CO_2 emissions (see Table 10.1 again). Conversely, the combustion of all types of hard coal is associated with very high CO_2 emissions, whether in terms of g CO_2/MJ or kg CO_2 per kg of matter. Properties not listed in Table 10.1 are ash content (varying from 4% to 10%) and sulfur content (0.3% to 1.1%). They may be of considerable relevance to the users of the fuel.

10.1.1 Biomass

Until the first half of the nineteenth century, firewood was the dominant fuel; yet with industrialization its supply could not keep up with demand. In its modern forms, biomass contributes but little to covering energy demand, for reasons that become evident from Fig. 10.1 which presents a classification of biomass fuels. Their potential depends on two parameters, the availability of land and its productivity. For instance, one ha of forest yields between 0.5 and 1.5 tons of dry matter per year but up to 15 tons if stocked with fast-growing trees (see short-rotation wood in Table 10.2). While residual timber from industry is economically quite attractive, its potential is largely exhausted since it cannot be burned untreated in countries with a restrictive greenhouse gas policy. Treated residual timber is more costly yet originally was charged with a disposal fee in some countries, causing it to

Table 10.1 Properties of solid fuels

Solid fuel	Water (%)	Lower heating value (MJ/kg)	CO_2 emissions (g CO_2/MJ)	CO_2 emissions (kg CO_2/kg)
Anthracite	6	35.6–37.7	95–98	2.43–3.69
Lean coal	6	33.5–35.6	92–98	3.08–3.49
Fat coal	6	29.3–33.4	92–98	2.70–3.27
Coke	9	28	94.6	
Hard lignite	20–30	16.8–29.3	97	1.63–2.84
Soft lignite	45–65	7.5–12.6	104–113	0.78–1.42
Lignite briquettes	19	19	94.60	0
Firewood pellets	10	18	0	0
Dry wood	18	ca. 15	0	0
Straw, reed, crops	15	14.5	0	0
Forest wood	50	ca. 8	0	0
Maize		ca. 3.5		

Data sources: Umweltbundesamt (2005) and Fachagentur nachwachsende Rohstoffe (2005)

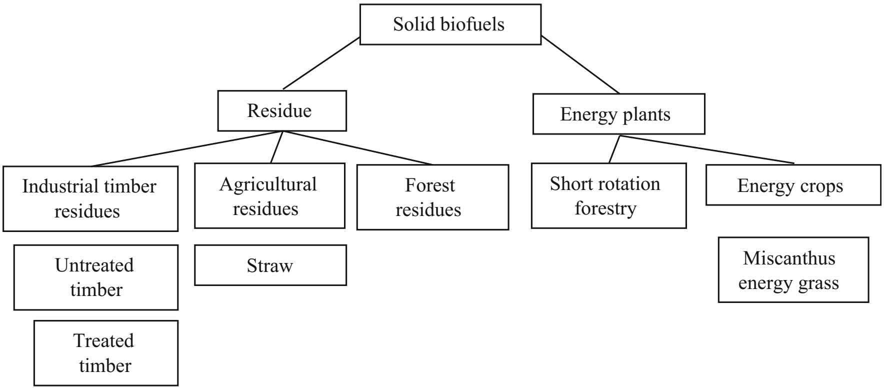

Fig. 10.1 Classification of solid biomass fuels

have a negative price. Meanwhile, it fetches a positive price, constituting one of the rare instances where a commodity changes from a negatively to a positively valued good.

An agricultural residue is straw, which however only yields up to six tons of dry matter per ha and year (see Table 10.2 again). Interestingly, it has an energy content of 17 MJ/kg, comparable to the other biomass fuels.

Turning to energy plants, Triticale is a novel cereal that can be used for nutrition or fuel production. Quite generally, biomass can be transformed into gaseous or liquid fuels by using biochemical processes (e.g. fermentation), chemical processes (e.g. esterification), or thermo-chemical processes (Fischer-Tropsch synthesis).

Table 10.2 Properties of solid energy biomass

	Dry matter (t/(ha a))	Lower heating value (MJ/kg)	Density (kg/m^3)	Price 2006[a] (EUR/tons)
Fresh firewood	0.5–1.5	18		
Split logs			300–500	30–60
Firewood chips			200–300	40–70
Wood pellets			400–600	120–300
Short-rotation wood/triticale	5–15	18		
Crops	8–14	17		
Straw	4–6	17		

[a]Without transportation cost
Data source: Carmen e.V. (bioXchange.de); see also Table 8.8

These processes are characterized by substantial energy losses, partly because only the starch and oil components of the biomass are suitable for energetic use. Up to present, cellulose, lignin, and tannin can only be used when burning wood, whereas an efficient thermal use requires the biomass to be shred and dried. This serves to increase its density up to 600 kg/m^3 (as in the case of wood pellets) and hence to lower its cost of transportation; however, these processes are themselves costly.

In sum, collection, transportation, and processing constitute the major cost components of solid biomass, which vary considerably depending on desired form of delivery (e.g. as piece goods or bulk goods) as well as topography. In addition, local and regional market conditions determine prices. Though firewood is typically cheaper than other fossil energy sources, it often loses this advantage due to higher outlays for burners, maintenance, and waste disposal.

10.1.2 Coal Reserves

The invention of the steam engine by James Watt in 1765 caused coal to dominate fossil energy markets for two reasons. On the one hand, it enabled the exploitation of underground coal mines because water could be pumped out in great quantities; on the other hand, growing coal extraction was necessary to run the steam engines. This mutual reinforcement of supply and demand is a typical feature of successful basic innovations to this day.

Although a non-renewable resource, coal has reserves that are still far from being exhausted. Their static range substantially exceeds 100 years (see Table 10.3). In view of this abundance, it is not surprising that a scarcity rent of coal is virtually nonexistent, in contradistinction with crude oil and natural gas (see the Hotelling model in Sect. 6.2.1). In addition, coal reserves are rather evenly distributed over the globe, with a large part located in industrial countries such as Australia, the United States, Canada, and China. For this reason, coal is called 'the energy source of the north'.

Table 10.3 Coal reserves and coal mining 2013

	Coal reserves 2013			Coal and lignite mining 2013	
	Hard coal (bn tce)	Lignite (bn tce)	Share (%)	(mn tce)	Share (%)
Russia	49.1	107.9	17.6	298	5.1
China	62.2	52.3	12.8	3680	47.4
Australia	37.1	39.3	8.6	478	6.9
India	56.1	4.5	6.8	605	5.9
European Union	4.9	51.2	4.5	543	3.9
South Africa	30.1	–	3.4	257	3.7
Indonesia	–	28.0	3.1	88	1.2
World	403.2	488.3	100	7896	100
OECD	155.5	229.3	43.2	2020	35.8

Source: BP (2014)

During the early coal era, mass transport of coal over long distances was quite expensive or even impossible, in spite of railways and inland waterways. Up to the nineteenth century it was cheaper to bring people to the coal than coal to the people. As a result, industrial clusters developed around coal fields, in particular iron, steel, manufacturing, and mechanical engineering industries. European examples are Central England, Northern France, the Meuse and Ruhr areas, and Upper Silesia. Today these regions are suffering from severe economic and social problems because electricity has replaced coal as the dominant energy source in production. Electricity can be transported to remote areas at low cost, thus lowering energy-related returns to agglomeration. Currently coal is used exclusively in electricity generation (as so-called steam coal) and steel production (as coke).

Nonetheless, global coal mining has kept expanding for many years for a number of reasons:

– Economic growth of emerging countries, in particular China and India, has been pushing demand for electricity and with it, coal;
– After several hikes in the prices of crude oil (see Sect. 8.3) and natural gas (see Sect. 9.3), coal has become a relatively inexpensive energy source;
– Many coal-producing countries have been reluctant to adopt greenhouse gas reduction strategies.

10.1.3 Surface and Underground Coal Mining

Two coal mining technologies can be distinguished, surface mining and underground mining (often simply called mining). The choice of mining technology is largely determined by the geology of the coal deposit. Surface mining (also known as opencast mining) requires the resettlement of households and companies who occupy a licensed mining area of many square kilometers—a socially sensitive, often conflict-laden, and time-consuming process. After closure of the mine, governments usually demand rehabilitation of the land, which is particularly costly in the case of surface mining. Yet surface mining can still be cheaper than underground mining if the coal beds are close to the surface, enabling the use of large-scale equipment and facilitating material flows comprising not only coal but also soil, rocks, and overburden removal.

Coal beds several hundred meters below the surface are exploited by underground mining through shafts and tunnels. Modern technology uses long wall mining, which involves the drilling of a section of 100–350 m length along the coal seam in one step using mechanical shearers. Self-advancing, hydraulically-powered supports temporarily hold the roof until the coal is extracted, after which the roof is allowed to collapse. While both surface and underground mining call for elaborate water management, the underground alternative additionally requires effort to prevent pit gas explosions that jeopardize miners' lives.[1] Another challenge confronting underground mining is surface subsidence affecting buildings, infrastructure, ground water, and local land use in its neighborhood.

The choice of technology has cost implications. Notably, labor productivity of surface mining ranges from 10,000 to 20,000 tons per worker and year, compared to 5000–8000 tons in underground mining—despite substantial increases in productivity. Since old mines have low marginal cost (see Sect. 1.2.1), surface mining tends to be more competitive than underground mining. This holds true in particular where infrastructure for transporting large volumes of coal to both domestic and international customers is in existence, creating scale economies.

10.1.4 International Coal Market

Steam coal accounts for about 70% of international trade in coal. It continues to be dominated by bilateral contracts (of the so-called over-the-counter or OTC type, respectively) between producers and wholesale customers. These contracts often have a duration of 10 years, with prices that are adjusted to the coal spot price annually in the fourth quarter. Since these prices need not be published, the world market for coal has been lacking transparency.

With the liberalization of electricity markets (see Sect. 12.2.2), the need for transparency has increased because generating companies seek to hedge their coal position on financial markets using regular price information. One such source are standardized surveys of traders, e.g. the weekly publication of the British *McCloskey Coal Information Services* (since 1991). Its quotations are in USD per metric ton of coal with a heating value of 6000 kcal/kg and a sulfur content of 1%. Another source is the British service provider *Tradition Financial Services* (*TFS*) who publishes a set of price indices, API#1 for the American market, API#2 for the

[1]Whereas extensive safety measures are used to protect miners in developed countries, developing and emerging countries regularly report major accidents in pits.

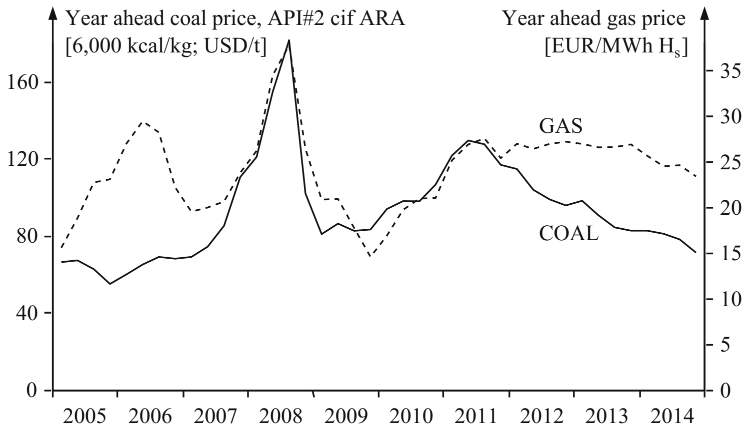

Fig. 10.2 Monthly coal and gas prices in Germany (data source: EEX). Note: 'cif. ARA' denotes inclusion of cost for insurance and freight for delivery to the ports of Amsterdam, Rotterdam, or Antwerp

European market, and API#4 for South Africa. Finally, energy exchanges such as the *European Energy Exchange* (*EEX*) also provide price data (see Fig. 10.2).

According to Fig. 10.2, coal prices spiked in 2008 and again in 2011, similar to those of natural gas and other fossil fuels. Starting in 2012, however, coal has become cheap compared to natural gas. Without attempting to explain these developments in detail, the following determinants can be cited.

– Decreasing coal exports from the United States: This country was home to major coal exporters until the end of the 1990s, who acted as swing producers. This stabilizing force has been absent since then.
– Development of Chinese coal exports: Caused by rapid economic growth, domestic demand for electricity and hence coal surged until 2012, reducing its availability for exports. This forced importing countries like Japan and Korea to obtain their supplies from more remote areas, causing freight rates to be bid up worldwide. Meanwhile, Chinese growth has slowed, making coal available again on the international market, with concomitant downward pressure on its price.
– The coal price in Europe also depends on the exchange rates of the Australian Dollar and the South African Rand. Australia and South Africa are home to major coal exporters, who quote their deliveries in their respective currencies.
– Finally, short-term price spikes may be caused by political and social unrest, military conflict, and outages of nuclear power.

10.2 The Greenhouse Gas Problem

More than 43% of energy-related CO_2 emissions originate from coal combustion, a share which is growing. In view of international attempts at mitigating the greenhouse gas problem in general and reducing CO_2 emissions in particular (see bottom lines of Table 10.4), the markets for coal cannot be discussed without addressing these issues.

The greenhouse gas (GHG) problem is the consequence of anthropogenic emissions of carbon dioxide (CO_2) and other greenhouse gases such as methane (CH_4) and nitrous oxide (N_2O, see Table 10.4) along with vapor into the atmosphere. According to climatologists, CO_2 allows short-wave solar light to pass the atmosphere while blocking the reflection of long-wave thermal radiation. Without this greenhouse effect, the mean temperature of the globe would be -18 °C rather than +16 °C at present. Since the beginning of industrialization around 1840, the CO_2 concentration in the atmosphere increased from 280 ppmv (parts per million by volume) to 390 ppmv as of 2011, according to the International Panel on Climate Change (IPCC). Over the same period, mean global temperature increased by 0.5 °C (possibly even by 0.8 °C, depending on method of measurement), suggesting that global warming is caused by the increase in CO_2 concentration.

Annual CO_2 emissions keep increasing globally (see Fig. 10.3). While they have been slowly falling in Europe and remaining stable in North America since about 2007, they have been growing rapidly in the rest of the world, most notably in China in the wake of its economic growth. This has to do with the fact that the most important anthropogenic source of CO_2 emissions is the burning of fossil fuels.[2] The GHG effect of other emissions is expressed in CO_2 equivalents. According to Table 10.4, the CO_2 equivalent of methane (CH_4) is 25 and of nitrous oxide (N_2O), 298 if a time horizon of 100 years is adopted. It is important to note that CO_2 is no poison in the classic sense—it is even necessary for the growth of plants. Yet at the current annual rate of more than 35 bn tons of global CO_2 emissions (40 bn tons of CO_2 equivalents from all GHG emissions, respectively), the GHG concentration in the atmosphere will continue to increase. This is likely to lead to a considerable increase in average global temperatures, which is believed to have many negative long-term impacts. Among those cited are acidification of oceans, increased frequency of thunderstorms, changing distribution of precipitation, desertification, melting of glaciers, thawing of permafrost, a rising sea level, and changing habitats for plants and animals. However, some of the world's regions may also benefit from increased plant growth and reduced heating requirements due to warmer temperatures. Since most of these regions are in the rich North while those

[2]Global methane emissions are much smaller than CO_2 emissions, and their rate of decay in the atmosphere is higher as well. But one mole of methane has an impact on the climate that is 56 times (over a time horizon of 20 years) or 21 times (100 years) greater than that of one mole of CO_2.

Table 10.4 Indicators of the greenhouse gas problem

	Carbon dioxide CO_2	Methane CH_4	Nitrous oxide N_2O
Pre industrial concentration (ppmv)	280	0.7–0.8	0.23
Average atmospheric lifetime (years)	5–200	9–15	120
Global warming potential in 20 years	1	72	289
Global warming potential in 100 years	1	25	298
Contribution to the GHG problem (%)	77	14	8
Reduction target of the IPCC 1990 (%)	60–80	15–20	70–80

Source: International Panel on Climate Change IPCC (1990, 2014)

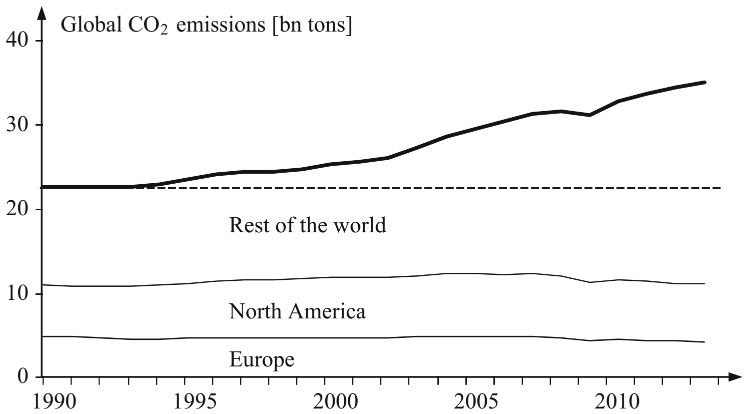

Fig. 10.3 Global CO_2 emissions (data source: BP 2014)

negatively affected are in the poor South, the GHG problem raises major equity concerns (Bretschger 2015, Chap. 4).

From the viewpoint of welfare economics, the reduction target should satisfy the following condition for Pareto optimality (see Sect. 7.2): The present value of expected damages avoided thanks to the last reduction project is to equal the present value of the expected cost of avoiding them. Note the qualification 'expected' on both sides of the equality; neither the amount of damage avoided nor the cost of meeting a reduction target are known with certainty. In particular, knowledge regarding future damage associated with present GHG emissions is not sufficient to implement the Pareto criterion. For example, Nordhaus and Boyer (2000) estimate the optimal CO_2 price (in the sense of a Pigouvian tax; see Sect. 7.3.1) to be around 10 USD per ton of CO_2. Therefore, this amount of tax would establish the equality of expected marginal benefit in the sense of damage avoided and expected marginal cost caused by reducing CO_2 emissions. By way of contrast, Böhringer and Rutherford (2000) conclude that even a rather modest reduction of GHG emissions would imply a cost of much more than 100 USD per ton of CO_2 equivalent. In view of divergences of this magnitude, there is no sound alternative for GHG reduction policy than to adopt the so-called standard-price approach (see Sect. 7.3.2).

The standard-price approach calls for a political decision with regard to a target value of emissions and putting a tax price on them that promises to reach this target. For example, let the long-term tolerable CO_2 concentration in the atmosphere be between 450 and 550 ppmv. The realized value is the result of annual CO_2 emissions and natural decay (Nordhaus 1994),

$$M_t = M_{t-1} - \frac{1}{\tau}\left(M_{t-1} - M_{pre}\right) + \beta \cdot Em_t. \tag{10.1}$$

Here, M_t symbolizes the realized CO_2 inventory at time t, which is given by the previous inventory M_{t-1} minus the decay of inventory added to its pre-industrial level M_{pre} plus the share β of current emissions Em_t that adds to the stock of CO_2. The parameter τ reflects the average duration of CO_2 in the atmosphere ($\tau = 120$ years according to the International Panel on Climate Change IPCC); therefore $1/\tau = 0.0083$ is the estimated rate of decay per year. As to β, Nordhaus (1994) estimates an OLS regression to obtain $\beta = 0.64$. Therefore, 64% of CO_2 emissions end up in the atmosphere rather than being sequestered by oceans and notably trees.[3]

Once the tolerable concentration of CO_2 equivalents is fixed, GHG emission trajectories can be calculated using Eq. (10.1). These trajectories have the property that annual reductions need to be larger the later they begin (see Fig. 10.4). According to Stern (2006, p. 201), GHG emissions would have to reach their maximum before 2025 and then decline at rates between −3 and −4% per year if the tolerable GHG concentration is set at 550 ppmv CO_2 equivalents. Along this path, the GHG stock should not exceed 400 ppmv by 2015. In view of the 390 ppmv concentration of CO_2 in that year cited above, there is not much time left to act.

The trajectories shown in Fig. 10.4 derive from welfare economics very much like the models of optimal resource depletion discussed in Sect. 6.3. While the constraint here is not the stock of resources but the maximum tolerable GHG inventory, social time preference plays a role again. It governs the speed with which fuels causing GHG emissions need to be substituted by capital. Moreover, the pace and direction of expected factor-augmenting technological change is important (see Sect. 5.4).

[3]More sophisticated models also take the complex physical and chemical exchange between atmosphere, oceans, and land surfaces into account.

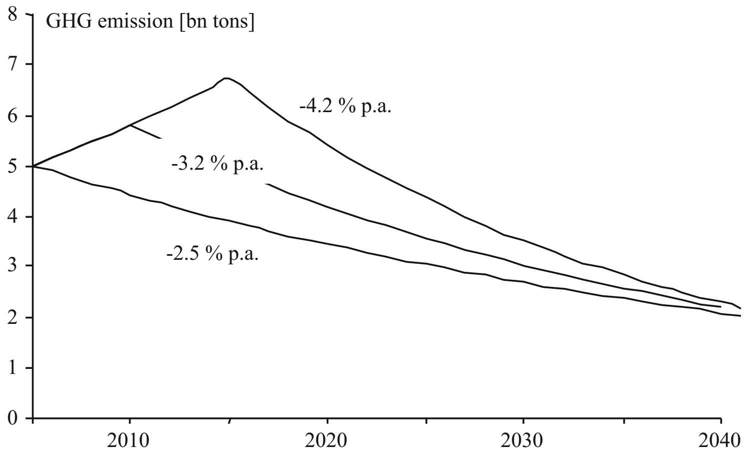

Fig. 10.4 GHG emission trajectories

Once the amount of tolerable emissions per year is determined, its distribution among claimants needs to be agreed upon, resulting in emission rights (also called emission allowances or permits). Several very different approaches exist:

– The grandfathering approach allocates permits according to emissions in a base period (e.g. the year 1990). It favors countries and industries with high emissions in the base year to the detriment of those with low emissions.
– The benchmark approach allocates allowances to industries such as power generation, production of steel and other base materials, transportation, and housing. Since the level of activity (measured e.g. by turnover) needs to be accounted for, rich countries stand to receive more emission allowances than poor countries.
– The egalitarian approach sets a uniform per-capita level of emissions. It therefore allocates permits predominantly to countries with large populations, typically poor ones.

10.3 Markets for Emission Rights

Any initial distribution of emission rights may be modified if rights are tradable. In keeping with the Coase theorem, this results in Pareto improvement (see Sect. 7.1). Emission trade would not only generate income for poorer countries through the sale of excess emission rights but also contribute to the overall efficiency of GHG abatement strategies. Figure 10.5 illustrates the argument. Let two companies cause certain amounts of emissions prior to the allocation of emission allowances. These amounts are determined by a marginal cost of abatement effort equal to zero, implying that neither company makes any effort. As soon as they begin to make

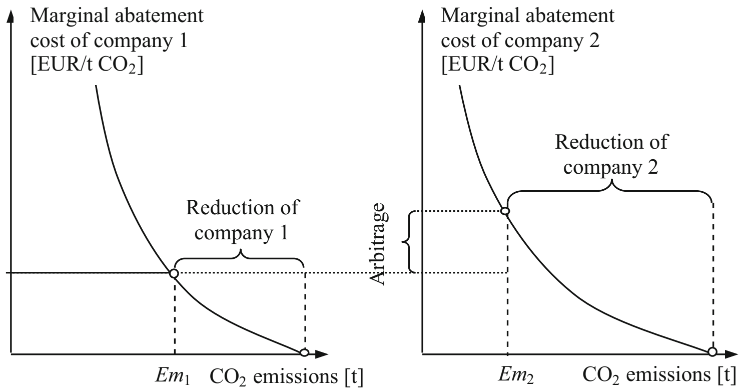

Fig. 10.5 Marginal emission abatement costs for two companies

effort designed to reduce emissions, they incur some cost of abatement. Let the marginal cost of these efforts increase when emissions are to be reduced. This assumption can be justified by noting that avoiding the first ton of e.g. CO_2 emissions usually does not cost much whereas avoiding another ton after a reduction by 100 tons becomes quite costly. Note that their marginal cost schedules usually differ. Let company 2 face more quickly increasing marginal cost than does company 1; for instance, it may have to pay higher wages to specialists who operate its abatement technology.

Now let the two companies obtain emission rights Em_1 and Em_2, respectively which are insufficient to cover emissions. Both companies therefore must reduce emissions, starting of course with the least costly measures (in terms of cost per ton of CO_2 avoided). In this way, they move up their respective marginal cost schedule until the remaining amount of emissions equals their respective permits Em_1 and Em_2. In the example shown in Fig. 10.5, this means that company 2 incurs much higher marginal cost for reaching its target than company 1. Its total abatement cost, given by the area below the marginal cost curve, is also higher.

For company 2, it would make economic sense to buy extra emission rights which would prevent it from moving up its marginal cost curve this far. It would be prepared to pay the marginal cost avoided for each permit. Company 1 in turn still benefits from its low marginal cost of abatement at Em_1. It would therefore have an incentive to reduce its emissions even further, enabling it to sell emission rights. It has an incentive to do so as long as the price for a permit paid by company 2 exceeds its marginal cost of abatement. Therefore, the difference in marginal cost at the respective values Em_1 and Em_2 creates scope for arbitrage trading which is profitable for both companies.

This arbitrage (characterizing a so-called cap-and-trade program) implies that company 1 reduces emissions beyond its allocation of rights Em_1, in return receiving revenue from selling them to company 2. On the other hand, company 2 purchases emission rights as long they are cheaper than its marginal abatement cost. In the optimum, arbitrage is eliminated through trade, resulting in equality of marginal abatement cost for both companies.[4]

In a dynamic perspective, the cap-and-trade program may motivate companies to intensify their emission abatement efforts. If successful, these efforts cause a downward shift of the marginal cost curves shown in Fig. 10.5. This has two consequences, which may occur in combination. The given amount of emission rights (and hence the emission target) can be attained at a lower cost; or at a given cost, the amount of emission rights can be reduced, reflecting a more ambitious target in terms of GHG concentration in the atmosphere.

Note that the introduction of a cap-and-trade program is not possible without the intervention of governments, who must determine the legal entities obliged to take part in it. In addition they need to verify emission reports and impose sanctions on those failing to comply. In the case of the emission trade system created by the European Union (EU-ETS; EU Commission 2003), a trading period extends over several years, presently from 2013 to 2020 and later on, from 2021 to 2030. Within a trading period, a shortfall of emission rights can be compensated by emission rights pertaining to the following year, whereas an excess of rights can be used not only during the following year but also during the entire next trading period. This raises the issue of the optimal length of a trading period: If the period is too long, the immediate incentive for reducing CO_2 emissions may be weak; if it is too short, the system does not incentivize investments that need time to be realized. Finally, governments must decide how the emission rights are to be distributed (see Sect. 10.2).

10.3.1 Prices for CO_2 Emission Rights

The European CO_2 emission trading system (EU-ETS) started in 2005. In its first year, it generated a volume of trade in excess of 320 mn tons of CO_2 emission rights along with financial transactions worth 8.2 bn EUR (Capoor and Ambrosi 2006, p. 13). Traders were not only operators of coal-fired power stations and steel works but also investment bankers.

As shown in Fig. 10.6, CO_2 prices shot up to almost 30 EUR/tons in 2005 but plunged to just about zero by 2007 (see below for an explanation). The jump back to prices above 25 EUR/tons in 2008 can be attributed to an increase in the fine for missing the target (or for failure to purchase a sufficient amount of emission rights, respectively) from 40 to 100 EUR/tons pursuant the European Directive 2003/87/EC (EU Commission 2003). In 2011 prices dropped again, likely because aviation

[4]Speculative trade may dominate markets for emission rights, depending on the expectations of market participants. If an increase in the price of certificates is expected, speculators go long (i.e. purchase rights in excess of marginal abatement cost) and *vice versa*. If their expectations turn out to be right, speculators make a profit, otherwise they suffer a loss.

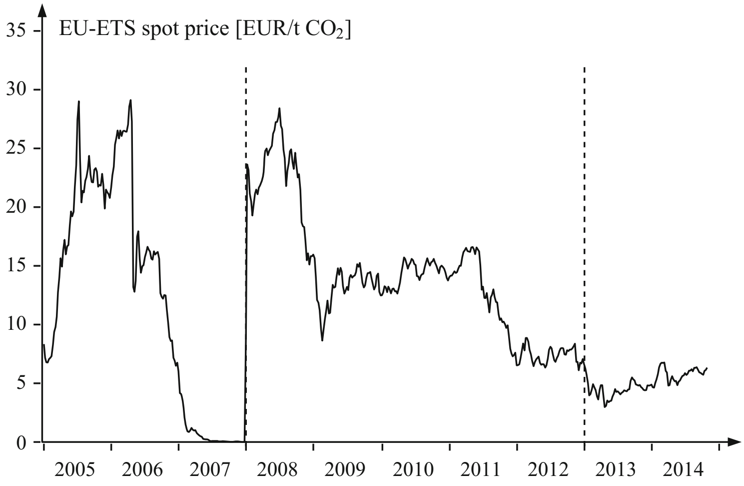

Fig. 10.6 Prices of CO_2 emission rights (data source: EEX)

was to be brought into EU-ETS in 2012, with 85% of the rights given away free of charge, however.

Since then, CO_2 prices have been consistently below 10 EUR/tons. According to the argument expounded above, this level should correspond to the marginal abatement cost of the last project that is required to meet the current European CO_2 emission target (derived from the GHG reduction target of 20% between 1990 and 2020). Such projects could be investments in energy-efficient production facilities but also in power plants that use natural gas or renewables instead of coal. At 10 EUR/tons CO_2, the wholesale price of hard coal would increase by 41%, from 0.8 to 1.13 EUR ct/kWh (see Table 10.5). By way of contrast, natural gas would become only 9% more expensive, from a higher base value of 2.2 EUR ct/kWh, however. At the resulting price of 2.4 EUR ct/kWh, natural gas is still too expensive to induce fuel switching.

This situation is likely to persist because on European markets, the price of coal has been low compared to that of natural gas for several years and may remain so even in the face of a more ambitious GHG policy (see Fig. 10.2). In addition, CO_2 prices during the first 10 years of EU-ETS have been rather volatile, causing risk-averse investors to shy away from projects designed to lower marginal abatement costs. Nevertheless, the European Union expects to achieve its GHG targets for 2020 (in spite of a substantial increase in German CO_2 emissions due to the country's '*Energiewende*') even in the absence of major growth in pertinent investment (EEA 2015). In fact, there are several options for reducing CO_2 emissions without investing in abatement technology. One is to move (parts of) the production from the European Union to regions without a CO_2 cap-and-trade system; another, to scale back electricity generation by coal-fired plants and to purchase power from outside the European Union (see Sect. 12.2).

Table 10.5 Energy wholesale prices in Germany given a CO_2 price of 10 EUR/tons

	Carbon content		Assumed wholesale energy price	Price markup (10 EUR/tons CO_2)
	(kg CO_2 per GJ)	(kg CO_2 per kWh)	(EUR ct/kWh)	(%)
Lignite	108	0.39	0.6	65
Hard coal	93	0.33	0.8	41
Heavy heating oil	78	0.28	1.2	23
Fuel oil	74	0.27	1.9	14
Natural gas	55	0.20	2.2	9

Data source: Umweltbundesamt (2005)

If participants in the market for CO_2 permits expect these alternatives to abatement to ensure that the EU-ETS is long at the end of the trading period, they abstain from purchasing emission rights while their price is high. This thought suggests that the CO_2 price is not anchored in the marginal cost of CO_2 abatement but rather depends on the market situation expected at the end of the trading period. A short market means that some companies cannot come up with enough emission rights and must pay the penalty of 100 EUR/tons (European Directive 2003/87/EC, EU Commission 2003). Therefore, they are willing to pay as much as the sum of the forward price plus this penalty for emission rights because they are obliged to make up for the shortfall of permits during the following trading period. Conversely, there is no reason to pay more than the forward price if the market is long since excess permits can be used later.

This argument provides an explanation of the price drop in April 2006 (see Fig. 10.6): Until that date, most market participants had assumed the market to be short at the end of the first trading period 2005–2007. Yet in April 2006, the European Commission reported that in 2005 available emission rights had exceeded emissions by about 60,000 tons. As these rights could be used until the end of 2007, there was no doubt that the market would be long at the end of the first trading period, causing CO_2 prices to be low until its end. Developments during the second trading period 2008–2012 can be explained in a similar way. Before September 2008 most market participants had expected a short market by the end of 2012 but revised their in view of the financial crisis and the ensuing recession in Europe. They (correctly) predicted a drop in the demand for electricity and hence in the demand for coal. Since the market would almost certainly be long at the end of the trading period, there was no reason to hoard emission rights; accordingly, the CO_2 price plunged from almost 30 EUR/tons to a minimum of 5 EUR/tons.

Many observers argue that the EU-ETS has failed because it cannot ensure CO_2 prices that are high enough to force coal-fueled power generation out of market. However, the EU-ETS was not invented to guarantee a certain CO_2 price but to reach ambitious emission reduction targets at the lowest possible economic cost. Since these targets have been met so far, the system has been rather successful—even more successful than originally thought. This is reflected in low CO_2 prices.

As long as the basic cap-and-trade principle of the EU-ETS is not abandoned, politicians can bring about a substantial increase in CO_2 prices by making market participants believe that the ETS market will be short at the end of the next trading period, e.g. by introducing more ambitious emission reduction targets. However, if market participants believe the market to be short at the end of the trading period, CO_2 prices will be close to the penalty of 100 EUR/tons or even exceed it, resulting in disadvantages for the international competitiveness of European industry.

10.3.2 Clean Dark Spread

In quite general terms, an excess of the sales price over marginal cost indicates an incentive to increase to increase production (see Sect. 1.2.2). It also approximates the profit margin since marginal cost usually is not much above average cost. In the case of coal-fired electricity generation, the difference between the sales price and the marginal cost of the fuel was originally called dark spread *DS*. In Eq. (10.2) below, p_{el} denotes the sales price of electricity (in EUR/MWh; see Sect. 12.2.3), while the purchase price of coal p_{coal} (given in EUR/MWh fuel) is divided by the fuel efficiency ω of the coal-fired power plant,

$$DS = p_{el} - \frac{p_{coal}}{\omega}. \tag{10.2}$$

Therefore, the higher the fuel efficiency of coal-fired generation, the cheaper is coal as a fuel. However, it is not a clean fuel; accordingly, the so-called clean dark spread *CDS* is calculated by adding $\alpha \cdot p_{CO2}$, the cost of CO_2 emission rights required for generating electricity to the efficiency-adjusted price of coal,

$$CDS = p_{elek} - \left(\frac{p_{coal}}{\omega} + \alpha \cdot p_{CO_2}\right). \tag{10.3}$$

The factor α represents the amount of CO_2 emissions (in tons) associated with the generation of one MWh of electricity. Among other things, it also depends on the fuel efficiency ω of the power plant. The (clean) dark spread is defined for power stations running on natural gas in an analogous way.

Since the marginal cost of electricity generation comprises more than the (efficiency-adjusted) price of the fuel and the cost of CO_2 permits, $CDS > 0$ is a necessary (but not sufficient) condition for a power station fueled by coal or natural gas to be viable in the long term (see Sects. 1.2.1 and 12.2.2). For German power stations fueled by hard coal, this condition was mostly met during the period from 2000 to 2014 (see Fig. 10.7). Indeed, the wholesale price of electricity moves largely in parallel with that of coal and the cost of CO_2 emission permits, the two major components of marginal cost. In view of the low own-price elasticity of the demand for electricity, an increase in marginal cost results in an almost commensurate increase in the market price (see Sect. 1.2.1). Thus, a higher CO_2 price drives up the wholesale price of electricity. This is even true of the period from 2005 to

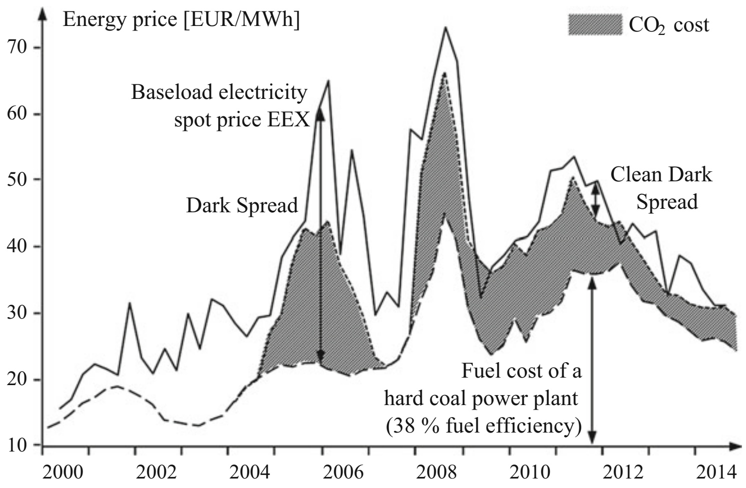

Fig. 10.7 German (clean) dark spread between 2001 and 2014

2007, when the German government gave emission rights to electricity generators for free (CO_2 prices represented an opportunity cost for plant operators). As argued in Sect. 10.3.1, generators expected the market for emission rights to be short by the end of the first ETS trading period, causing their price to be positive up to 2007, when it became clear that the market would be long.

These observations suggest that the price of electricity and the marginal cost of coal as given by Eq. (10.3) may be driven by a common stochastic trend. In fact, the 169 monthly day-ahead electricity prices p_{el} and the marginal cost of German coal-fired power stations (with an assumed fuel efficiency of 38%) turn out to be stationary after differentiation with respect to time (see Sect. 9.3.2). Therefore, the two time series are integrated of order one, and the appropriate statistical tests do not reject the following cointegration equations,

$$\begin{aligned} &\text{Baseload electricity price} \quad p_{el\_base} = 1.31 \cdot \left(\frac{p_{coal}}{\omega} + 0.88 \cdot p_{CO_2}\right); \\ &\text{Off-peak electricity price} \quad p_{el\_offpeak} = 1.09 \cdot \left(\frac{p_{coal}}{\omega} + 0.88 \cdot p_{CO_2}\right). \end{aligned} \tag{10.4}$$

According to the first equation, the CDS for German baseload power traded on the spot market was 31% of marginal generation cost (see Sect. 12.2.3). Since baseload capacities are also needed to meet peak load demand, whose own-price elasticity of demand is particularly low (see Filippini 2011), this high value is intuitive. It also implies that an increase in the price of CO_2 emission rights can be passed on to buyers more than proportionally (1.15 = 1.31·0.88). By way of contrast, the *CDS* reduces to 9% for off-peak power, whose own-price elasticity of demand is higher. Accordingly, a higher price of CO_2 emission cannot be fully passed on to buyers (0.96 = 1.09·0.88).

According to Fig. 10.7 *DS* and *CDS* have declined during the observation period. This is the likely consequence of successful efforts by the regulator designed to reduce the market power of German generators as well as the growing importance of renewable electricity generation, which both put pressure on wholesale electricity prices. While the clean dark spread was still positive most of the time up to 2014, it was no longer sufficient to justify investment in coal-fired power plants (see Sect. 12.3.3 for a discussion of capacity investment in deregulated markets for electricity). It is important to note that this situation cannot be attributed to the EU-ETS, as higher CO_2 prices can be passed on just about one-to-one to the purchasers of electricity on the wholesale market, as shown above.

10.3.3 Coal Perspectives

Prices for CO_2 emission rights have been quite low in recent times (see Fig. 10.6 again). They thus do not create an economic incentive to develop clean coal technologies that would allow stabilizing and reducing greenhouse gas emissions while using the abundant global coal resources. In addition, coal-fired electricity generation has average fuel efficiencies below 35%. If it could be raised to 45% (the value characterizing modern power stations), global CO_2 emissions from this source could be reduced by 25%. Given that global CO_2 emissions amounted to an estimated 14.8 bn tons in 2013 (IEA 2016), the reduction would be at least 3.7 bn tons per year.

However, at CO_2 prices above 50 to 70 EUR/tons, analysts predict that carbon capture would become an attractive option for operators of coal-fired power plants. The following alternatives are being discussed.

– Post-combustion capture: The CO_2 is washed out of the flue gas after combustion. A retrofitting of existing power plants is possible, but with the downside of reduced fuel efficiency.
– Pre-combustion capture: CO_2 is removed from coal (and fossil fuels more generally) before combustion. One option is to use integrated coal gasification technologies (IGCC) such as Fischer-Tropsch synthesis which produces so-called synthesis gas under high temperature and pressure. The gas is a mixture of hydrogen H_2, carbon monoxide CO, carbon dioxide CO_2, and smaller amounts of other gaseous components, such as methane CH_4. The so-called water-gas shift reaction uses the remaining CO and water H_2O as inputs that are converted into H_2 and CO_2. By capturing and separating the CO_2, the remaining H_2-rich fuel can be used in combustion processes without any greenhouse gas emissions.
– Flue gas capture: Coal is burned using pure oxygen O_2 rather than air. The flue gas contains only steam and CO_2, which can easily be separated.

For these technologies to be environmentally friendly, a release of the captured CO_2 into the atmosphere must be avoided. Apart from non-energetic uses of CO_2, a solution widely discussed is underground storage (carbon capture and storage CCS). This technology is being applied on a large scale in advanced oil and gas extraction, with exhausted gas fields serving as storage locations. Yet carbon-capture technologies are generally far from being mature, a state of affairs unlikely to change as long as the price of CO_2 emissions remains low.

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