1 Energy Markets

Worldwide energy consumption will continue to grow over the next decades. Depending on the economic growth scenario, the average annual growth rate of energy consumption is estimated between 1.5% and 2.6% (Energy Information Administration 2006) with significant differences among the countries. In the reference scenario of 2% worldwide growth rate, non-OECD Asia (including China and India) grows at a rate of 3.7% per year whereas the OECD countries grow only at a rate of 1% per year. The projections for the reference scenario are shown in Figure 1.1.

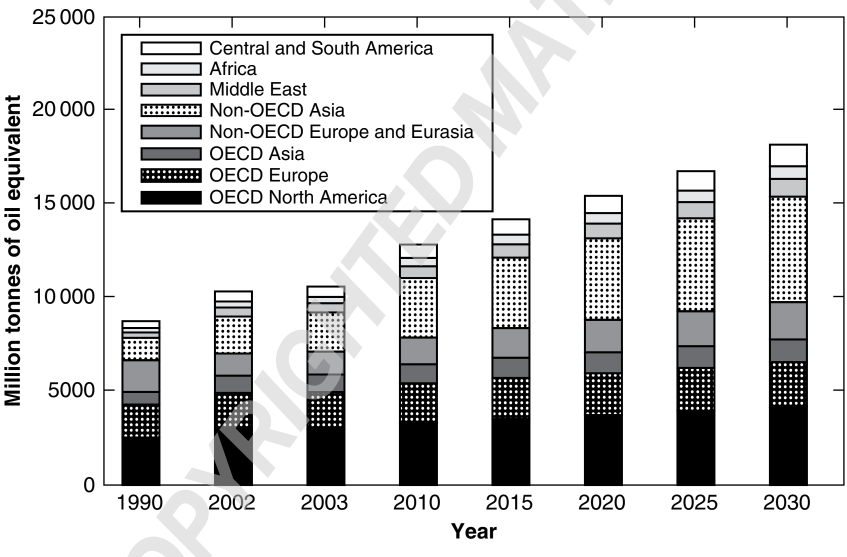

Figure 1.1 World energy consumption outlook by regions (reference scenario). Source: Energy Information Administration (2006)

The main primary energy source worldwide is oil covering 39% of worldwide energy consumption (see Figure 1.2). Second are coal and natural gas each covering 24% of energy consumption. Nuclear energy (6%) and others (8%) have a much smaller share. To meet the growing worldwide demand for energy, there will be an increase in energy consumption from all primary energy sources (Figure 1.3). However, the growth rates for natural gas and coal are expected to be larger than for oil, such that in the year 2030 oil will have a reduced share of only 33%. The shares of coal and natural gas will increase to 27% and 26% respectively.

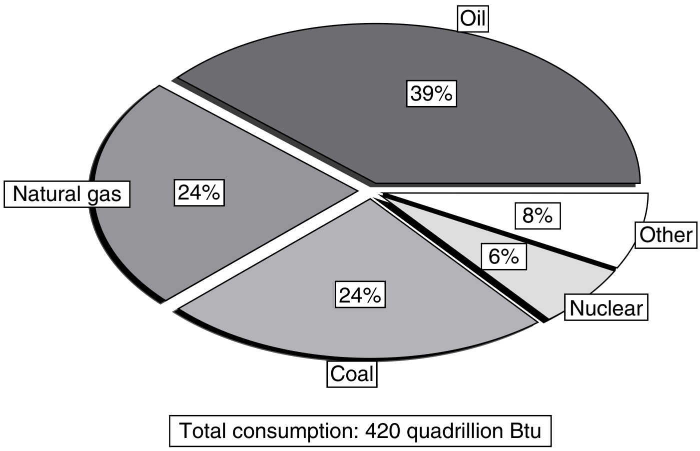

Figure 1.2 World primary energy sources outlook. Source: Energy Information Administration (2006)

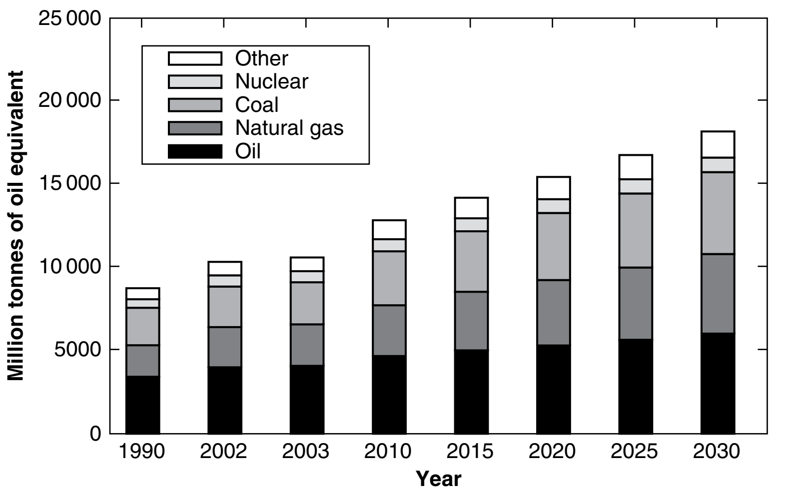

Figure 1.3 World primary energy sources outlook. Source: Energy Information Administration (2006)

The following list gives an overview of energy consumption by end user sectors (Energy Information Administration 2006):

- *Residential sector*: The residential sector (households) uses energy for heating, air conditioning, lighting and power consumption. This sector accounts for 16% of total energy consumption. The energy is delivered mainly in the form of gas, oil and electricity. In the residential sector, there is a strong growth of energy consumption in the non-OECD countries due to growing populations and economic development.
- *Commercial sector*: Consumption in the commercial sector (services and institutions) accounts for 8% of total energy consumption. Within this sector, electricity has the largest share among the different forms of energy.

- *Industrial sector*: The industrial sector includes manufacturing, agriculture, mining and construction. This sector accounts for 49% of total energy consumption and has the highest growth rate of 2.4% mainly driven by economic growth in the non-OECD countries. The most important energy sources in this sector are oil, gas, coal and electricity.
- *Transportation sector:* Consumption in the transportation sector accounts for 27% of total energy consumption and is dominated by oil with a share of 97%.

With the development of a global oil market in the 1980s, energy has become a tradable commodity. In the early 1990s, the deregulation of the natural gas market in the United States led to a liquid and competitive gas market. In Europe, a developed natural gas market exists so far only in the UK, but the process of market liberalisation has also started in continental Europe. The deregulation of the electricity markets in the United States and in several European countries started during the late 1990s and is still continuing (see section 1.4).

The subsequent market overviews use a number of trading terms, some of which will be defined in more detail in the later chapters. The basic trading products mentioned in this chapter are

- *Spot transaction*: Physical transaction with nearby delivery of the commodity.
- *Forward contract*: Bilateral agreement to purchase or sell a certain amount of commodity on a fixed future date (delivery date) at a predetermined contract price.
- *Futures contract*: Exchange traded standardised agreement to purchase or sell a certain amount of a commodity on a fixed future date (delivery date) at a predetermined contract price. Often, there is a financial settlement paying only the value of the commodity at the delivery date instead of a physical delivery.
- *Commodity swap*: A fixed cash flow specified by a fixed commodity price is exchanged against a varying cash flow calculated from a published commodity price index at the respective fixing dates.
- *Option*: An option holder has the right but not the obligation to purchase or sell a certain commodity at a predetermined strike price.

A detailed description of the different trading products is given in Chapter 2.

Bilateral agreements are said to be traded *over-the-counter* (OTC). Such trades are concluded mostly on the phone or through Internet-based broker platforms. For trades concluded at a commodity exchange, the exchange serves as a central counterparty for all transactions. Meanwhile, a number of futures exchanges for energy related commodities exist. The exchanges with global significance are listed below:

- *New York Mercantile Exchange (NYMEX)*: NYMEX is the world's largest physical commodity futures exchange. The wide array of products offered by NYMEX includes futures and options contracts for energy (electricity, oil products, coal, natural gas) and metals (gold, silver, copper, aluminum and platinum). NYMEX light sweet crude oil futures contract introduced in 1983 and NYMEX Henry Hub natural gas futures contract introduced in 1990 have become the most popular energy benchmarks in the United States.
- *Intercontinental Exchange (ICE)*: ICE was founded in May 2000 with the objective of providing an electronic trading platform for OTC energy commodity trading. ICE expanded its business into futures trading by acquiring the International Petroleum Exchange (IPE)

in 2001. ICE's products include derivative contracts based on the key energy commodities: crude oil, refined oil products, natural gas, and electricity. Recently, ICE introduced emissions futures contracts in conjunction with the European Climate Exchange in Amsterdam (see section 1.5). The ICE Brent futures contract serves as an important international benchmark for pricing oil cargos (see section 1.1) in Europe.

There are several other energy exchanges with a focus on specific local markets for electricity or natural gas. Descriptions of those exchanges are included in the subsequent sections.

Unlike in financial markets, the point of delivery plays an important role in commodity trading, since transportation can be costly (coal, oil) or dependent on access to a grid (power, gas). Therefore commodity prices are usually quoted with a reference to the delivery point. Typical delivery points depend on the type of commodity, e.g. Richards Bay in South Africa for coal or Amsterdam–Rotterdam–Antwerp (ARA) for oil or coal. Another important specification for physical commodity trades are the *Incoterms* (international commerce terms) dealing with the clearance responsibilities and transaction costs. The most important Incoterms for energy markets are:

- *Free On Board (FOB)*: The seller pays for transportation of the goods to the port of shipment and for loading costs. The buyer pays for freight, insurance, unloading costs and further transportation to the destination. The transfer of risk is at the ship's rail.
- *Cost, Insurance and Freight (CIF)*: The selling price includes the cost of the goods, the freight or transport costs and also the cost of marine insurance. However, the transfer of risk takes place at the ship's rail.

1.1 THE OIL MARKET

The oil market is certainly the most prominent among the energy markets. *Crude oil* (or *petroleum*) is found in reserves spread across particular regions of the earth's crust, where it can be accessed from the surface. Even though petroleum has been known and used for thousands of years, it became increasingly important during the second half of the 19th century as a primary energy source and as a raw material for chemical products. Today, crude oil is still the predominant source of energy in the transportation sector and is often taken as a benchmark for the price of energy in general. In Europe, for example, prices of natural gas are typically derived from oil prices. Therefore oil prices also have an impact on electricity prices, even though oil plays a minor role as a primary energy source for electricity generation.

Because of oil's great economic importance, oil markets have always been subject to political regulations and interventions. Figure 1.4 shows the historical spot prices for Brent crude oil. Clearly, the oil price is influenced by political events, which explains, for example, the price spike during the First Gulf War 1990/91. In addition, there are long-term economic developments, such as the increase of oil demand in Asia or decreasing reserves/production ratios in some areas of the world.

1.1.1 Consumption, Production and Reserves

Oil consumption and oil production are unevenly distributed across the world. The majority of the world's oil consumption is located in the developed countries in North America,

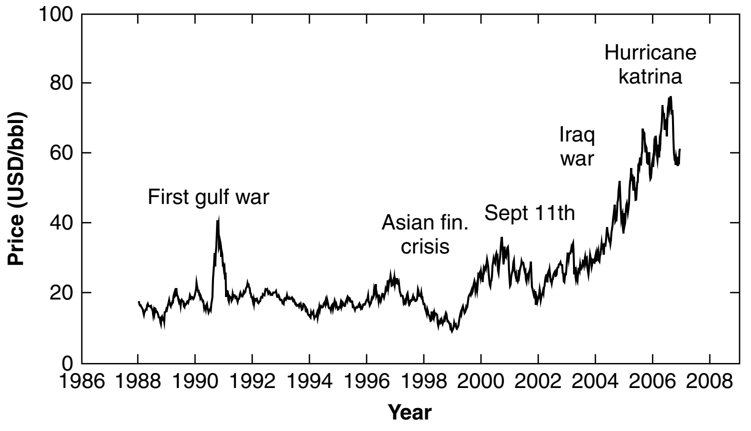

Figure 1.4 Brent historical spot prices. Source: http://www.econstats.com

Europe and Asia (see Figure 1.5), whereas the majority of production is located in developing or transition countries (see Figure 1.6). This imbalance is even more pronounced for oil reserves: 66% of the oil reserves are located in countries in the Middle East (see Figure 1.7). The OPEC member countries control over 40% of the world's oil production and 80% of all known conventional oil reserves. Apart from the known reserves, which can be accessed by conventional methods, there is an increase in known reserves due to improvements in production technology and there are unknown reserves still to be explored.

The *reserves-to-production ratio* describes the number of years that known reserves are estimated to last at the current rate of production. The worldwide reserves-to-production ratio 2005 was approximately 37 years with great differences among the regions (see Figure 1.8). For OPEC members, the reserves-to-production ratio was 73 years, whereas for non-OPEC countries the ratio was only 13 years. As mentioned earlier, reserves are expected to grow over the next decades. On the other hand, oil consumption and therefore oil production are also expected to grow over the next decades. Different scenarios for the world's economic

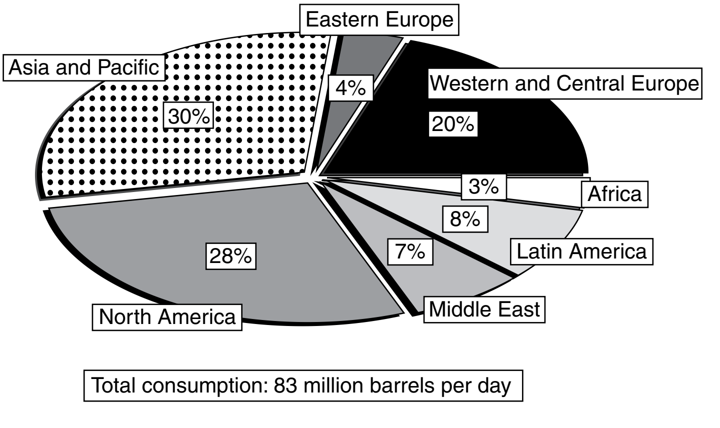

Figure 1.5 World oil consumption 2005 by region. Source: Eni S.p.A. (2006)

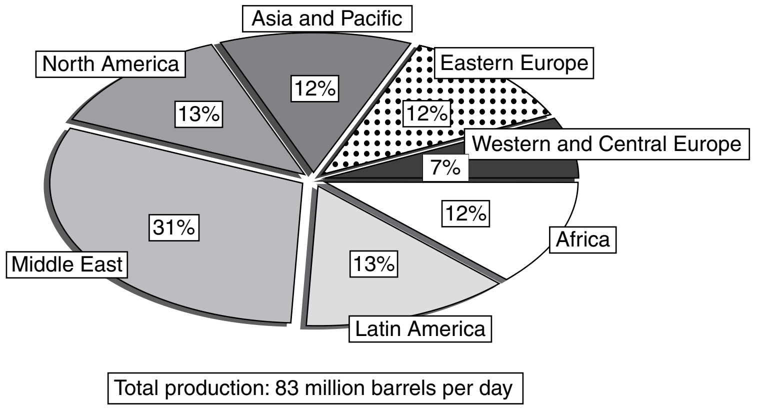

Figure 1.6 World oil production 2005 by region. Source: Eni S.p.A. (2006)

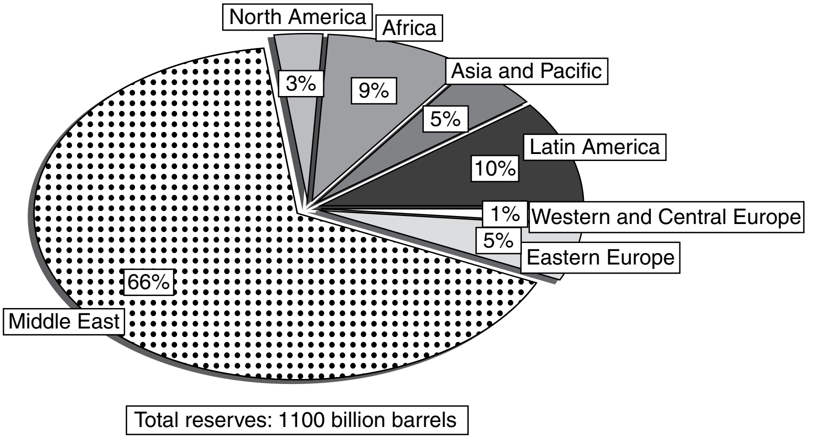

Figure 1.7 World oil reserves 2005 by region. Source: Eni S.p.A. (2006)

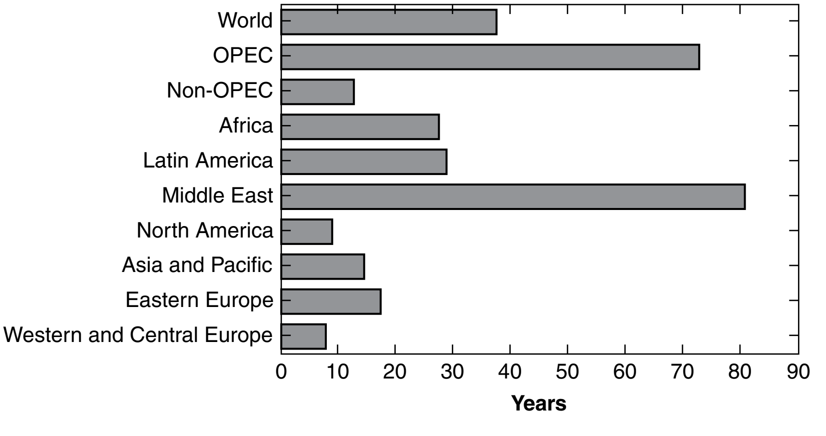

Figure 1.8 Reserves-to-production ratio 2005 by regions. Source: Eni S.p.A. (2006)

growth (see Energy Information Administration 2006) assume an average annual growth rate of 0.9% to 2.0% for the world's oil consumption. This means that in 2030, global oil consumption is estimated to be between 103 and 137 million barrels per day compared to 83 million barrels in 2005.

Depending on its origin, oil can be of different quality. The main characteristics are viscosity and sulphur content. Fluid crude oils with low viscosity have a lower specific weight and are called *light* crudes. With increasing viscosity and specific weight the crudes are called *intermediate* and then *heavy*. Lighter crude oils are more valuable, since they yield more marketable products. Crude oils with a sulphur content of less than 1% are called *sweet*, otherwise they are called *sour*. Since a high sulphur content causes additional costs in the refinery process, sweet crude oils are priced at a premium.

1.1.2 Crude Oil Trading

The physical crude oil market has to deal with a large variety of different oil qualities (viscosity, sulphur content) and with different means of transportation (pipeline, shipping). All of these characteristics influence the oil price. Nevertheless, a liquid oil market has developed, using few reference oil qualities as benchmarks for pricing an individual oil quality. The most popular benchmark oils are:

- *West Texas Intermediate (WTI)*: Reference for the US market. Sulphur content: 0.3%.
- *Brent*: Reference for the North Sea oil market with a similar quality as WTI. Sulphur content: 0.3%.
- *Dubai*: Reference for the Middle East and Far East markets. Sulphur content: 2%.

As the original Brent crude stream has declined over the last decades, the *Brent BFO* index has been created combining Brent, Forties and Oseberg streams. Besides WTI, the Brent BFO index has become the most popular benchmark index for crude oil transactions. Typical physical transactions for BFO crude oil are specified as FOB Sullom Voe (Shetland Islands, UK).

The structure of the physical market for BFO crude oil is connected with its nomination procedure. The sellers are obliged to tell their counterparts 21 days in advance of the first day of the three-day loading window when the cargo will actually be loaded. The final loading schedule is then published by the terminal operator. A contract with an already nominated loading window less than 21 days ahead is called *dated Brent*. The *21-day forward market* trades contracts for delivery up to multiple months ahead where the exact loading window is not yet known and will be nominated 21 days in advance. A typical crude oil cargo has a size of about 500 000 bbl.

The need for producers and consumers to financially hedge oil price risks and the growing importance of oil derivatives for asset managers and speculators gave rise to a very large market of financial instruments connected to oil. The most important commodity exchanges offering oil futures and options are NYMEX for WTI contracts and ICE for Brent contracts. Both WTI and Brent contracts are monthly futures contracts quoted in USD per barrel with a contract size of 1000 bbl. Typically, only the next few months are traded liquidly. For longer-term maturities, there is a liquid OTC market for WTI or Brent swaps.

The ICE Brent Crude Futures Contract was launched 1988 by the former IPE (International Petroleum Exchange). It allows for physical settlement (exchange-for-physical) and for cash settlement. Delivery periods are monthly. Highest liquidity is in the first three delivery months. The last trading day for a specific delivery month is the day before the 15th of the month preceding the delivery month. In case of cash settlement, the underlying price is the ICE Futures Brent Index on the day after the last trading day for this contract. It represents the average price in the 21-day market for the delivery month and is calculated from the appropriate 21-day BFO deals.

The hedging instruments for the 21-day market do not cover the most volatile short-term end of the Brent forward cuve for dated Brent. For this purpose, the *contract for differences* (CFD) has been introduced. A CFD is an over-the-counter swap. The swap buyer receives the weekly mean price for dated Brent and pays the weekly mean price for the front month 21-day Brent contract. In this way, a buyer of a physical Brent cargo priced at dated Brent plus a premium or discount of x USD/bbl can hedge his price risk by entering into a CFD contract converting the dated Brent price into a 21-day forward price. For the 21-day forward price there are standard hedging instruments available.

The long-term forward market for crude oil is dominated by Brent and WTI swaps exchanging a fixed monthly payment against a floating payment, which is the monthly average of the front month futures price. The swap market covers a time period of up to 10 years.

1.1.3 Refined Oil Products

As described earlier, crude oil can be of various qualities concerning its density and sulphur content. To become marketable, *refineries* convert crude oil into various products. The refining process in its basic form is a distillation process, where crude oil is heated in a distillation column. The lightest components can now be extracted at the top of the column whereas the heaviest components are taken out of the bottom of the column. To increase the yield of the more valuable lighter products, a *cracking* process is used, breaking up the longer hydrocarbon molecules. Other processes are needed to remove the sulphur content. Ordered by increasing density, the most important oil products are:

- *Liquefied petroleum gases (LPG)*: Propane or butane.
- *Naphta*: Mainly used in chemical industry.
- *Gasoline*: Mainly used for transportation.
- *Middle distillates*: Kerosine, heating oil and diesel.
- *Fuel oil*: Used in thermal power plants and large combustion engines (factories, ships).

Worldwide there are approximately 700 refineries to match the demand for the different oil distillates (see Figure 1.9). Since building new refineries is a complex project involving very large investments, refining capacities react slowly to changes in demand. Owing to the combined production process, prices of different oil products are usually tightly related to each other and can be expressed in terms of price spreads against crude oil. The lighter and more valuable products have higher spreads against crude oil than the heavier products. In special circumstances, such as a military crisis, prices for certain products (e.g. jet fuel) can spike upwards in relation to crude oil because of the limited refining capacities and the limited flexibility of refineries to change the production ratios among the different products.

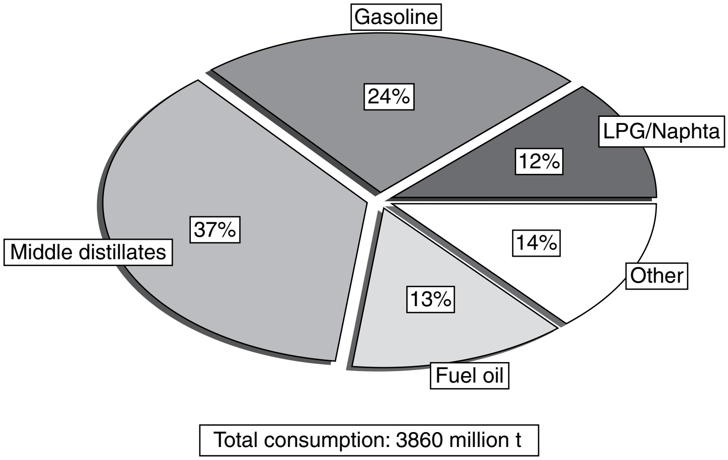

Figure 1.9 Refined oil products: consumption in 2005. Source: Eni S.p.A. (2006)

The European market for refined oil products is divided into ARA (Amsterdam–Rotterdam–Antwerp) and Mediterranean (Genoa). Typical lot sizes for these contracts are barges that correspond to 1000 to 5000 (metric) tonnes.

The most important refined product in Europe is gasoil, which is used for domestic heating and for transportation (diesel). Improvements in diesel engine technology and tax incentives have led to a strong growth of diesel consumption in Europe. Fuel oil plays a limited role, but is still frequently used as a price reference for natural gas contracts.

Typical financial instruments for European gasoil are:

1. *Gasoil swaps*: Gasoil swaps are traded OTC and typically refer to the monthly average gasoil price (ARA or Mediterranean) as published by Platts for setting the floating payments.
2. *ICE gasoil futures*: ICE offers monthly gasoil futures contracts FOB Rotterdam.

In Germany, typical reference prices for HEL (gasoil) and HSL (fuel oil) are published monthly by the “Statistisches Bundesamt”. They include certain taxes and transportation costs down the river Rhine. Those *Rheinschiene* prices are often referred to in German natural gas contracts.

1.2 THE NATURAL GAS MARKET

Next to oil and coal, natural gas is one of the most important primary energy sources covering about 25% of worldwide energy consumption. It is primarily used as a fuel for electricity generation, for transportation and for domestic heating. Natural gas consists mainly of methane (CH_4), which is the shortest and lightest in the family of the hydrocarbon molecules. Other components are heavier hydrocarbons, such as ethane, propane and butane, and contaminants, such as sulphur. Natural gas is usually measured in cubic metres. The combustion heat stored in one cubic metre of natural gas at normal atmospheric pressure is about 10.8 kWh (36 850 Btu), but can vary depending on the specific quality. This section gives a general market overview. For economical modelling approaches see section 4.6.

1.2.1 Consumption, Production and Reserves

Worldwide natural gas consumption has a higher growth rate than oil consumption. Between 1994 and 2004 worldwide natural gas consumption increased by 30%, whereas oil consumption increased only by 20%. The global gas consumption in 2004 was 2760 billion cubic metres, which has an energy equivalent of about 30 000 TWh. Figure 1.10 shows how gas consumption is distributed across the different areas of the world.

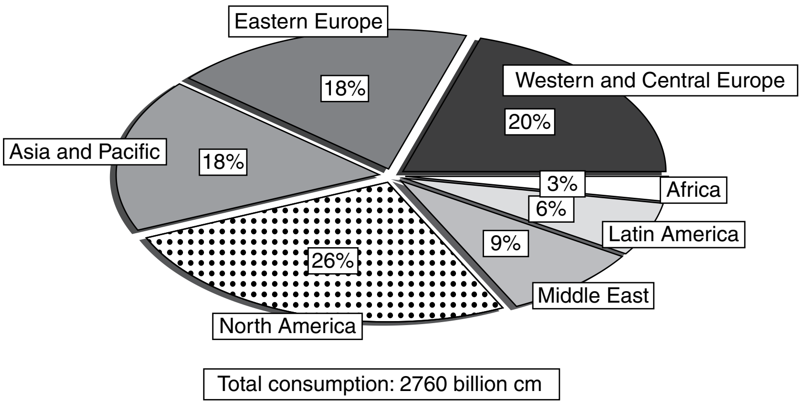

Figure 1.10 World gas consumption 2004 by regions. Source: Eni S.p.A. (2006)

Natural gas is found in the earth's crust mostly in gas or oil fields. Unlike oil, because of its low density, gas is difficult to store and transport. In the past, gas found in oil fields was therefore simply burned without any economic use. With growing demand for primary energy sources, gas prices have risen and large investments have been made to build up an infrastructure for gas transportation, either in the form of pipelines or in the form of liquefied natural gas LNG terminals (see section 1.2.4). The countries with the highest gas production are Russia, the United States and Canada selling most of their gas via pipelines. LNG exports, however, are becoming more and more important with rising gas prices and new investments in LNG terminals. Figures 1.11 and 1.12 give an overview of production volumes and reserves for natural gas.

The proven natural gas reserves amount to about 184 000 billion cubic metres (see Eni S.p.A. 2006). At the current production rate, those reserves are estimated to last for 66 years with large differences for the different areas (see Figure 1.13). In the Middle East the reserves-to-production rate exceeds 200 years, whereas in North America or in Western and Central Europe the reserves-to-production rate is about 20 years or below. Those countries will depend more and more on gas imports. Besides the proven reserves there are still undiscovered reserves estimated at more than 100 000 billion cubic metres (see Energy Information Administration 2006).

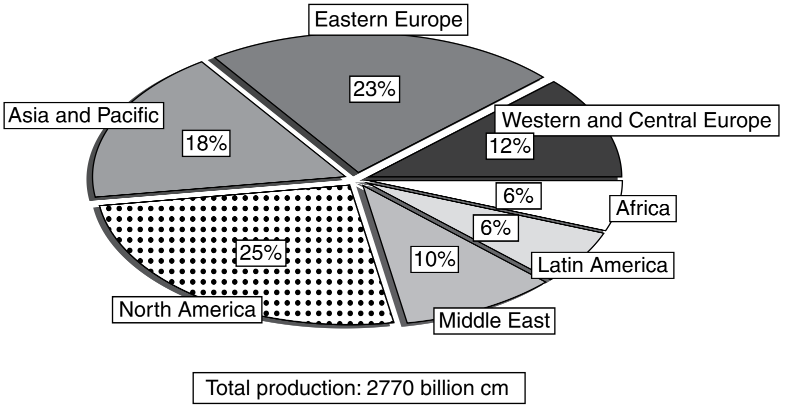

Figure 1.11 World gas production 2004 by regions. Source: Eni S.p.A. (2006)

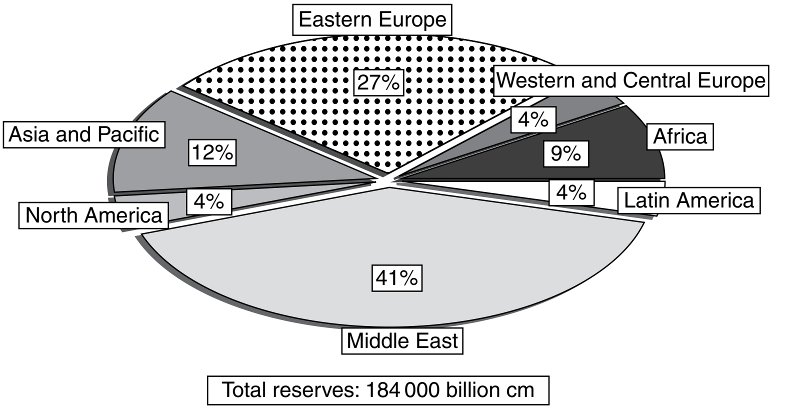

Figure 1.12 World gas reserves 2004 by regions. Source: Eni S.p.A. (2006)

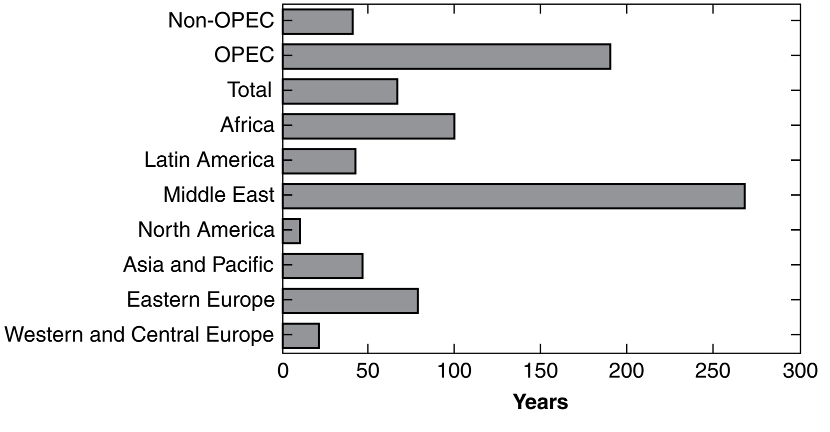

Figure 1.13 Reserves/Production ratio 2004 by regions. Source: Eni S.p.A. (2006)

1.2.2 Natural Gas Trading

Compared to oil the natural gas market is more regional due to the high costs of gas transportation. The following regional markets can be distinguished:

- The North American market.
- The European market.
- The Asian market.

Historically, those regional markets have had little interaction, since LNG played a significant role only for the Asian market. With declining gas reserves and growing demand in North America and Western Europe, the importance of LNG for those markets, and therefore the market interaction, will increase over the next decades.

The North American Market

The United States is an importer of natural gas. The main imports are via pipeline from Canada, but more and more LNG imports are needed to serve gas demand. The gas market is liberalised and competitive. The highest liquidity is found at Henry Hub (Louisiana) in the Gulf of Mexico. Besides a liquid spot market there is also a very liquid futures market introduced by NYMEX in 1990. The range of products offered by NYMEX includes options on gas futures and spreads between Henry Hub and other US gas hubs.

Monthly NYMEX Natural Gas Futures have the following specification:

- *Trading unit*: 10 000 million British thermal units (MBtu).
- *Price quotation*: USD and cents per MBtu
- *Trading months*: The current year and the following five years.
- *Last trading day*: Three business days prior to the first calendar day of the delivery month.
- *Settlement type*: Physical delivery at Henry Hub in Louisiana at a uniform rate over the delivery month.

The European Market

The main exporters to serve Western European demand are Russia, Norway, the Netherlands and Algeria via pipelines. Opposed to the UK, where a liberalised market for gas exists, the market in continental Europe is still dominated by long-term contracts indexed to oil prices (see section 1.2.3).

The most important gas trading hubs in Europe are listed below:

- The National Balancing Point (NBP) in the UK.
- Zeebrugge in Belgium.
- Title Transfer Facility (TTF) in Netherlands.

The continental European market and the UK market are linked by the *Interconnector* pipeline that began operation in 1998. The Interconnector has a length of 230 km and connects Bacton, UK, with Zeebrugge, Belgium. The pipline has a capacity of 20 billion cubic metres of gas per year to transport gas from Bacton to Zeebrugge (forward flow) and a capacity of 23.5 billion cubic metres in the reverse direction (reverse flow). The Interconnector is owned by BG Group (25%), E.ON Ruhrgas (23.59%), Distrigas (16.41%), ConocoPhillips (10%), Gazprom (10%), Total (10%) and ENI (5%). The historical monthly net gas flows are shown in Figure 1.14. Due to decreasing gas production in the UK, the Interconnector is increasingly used in reverse flow direction.

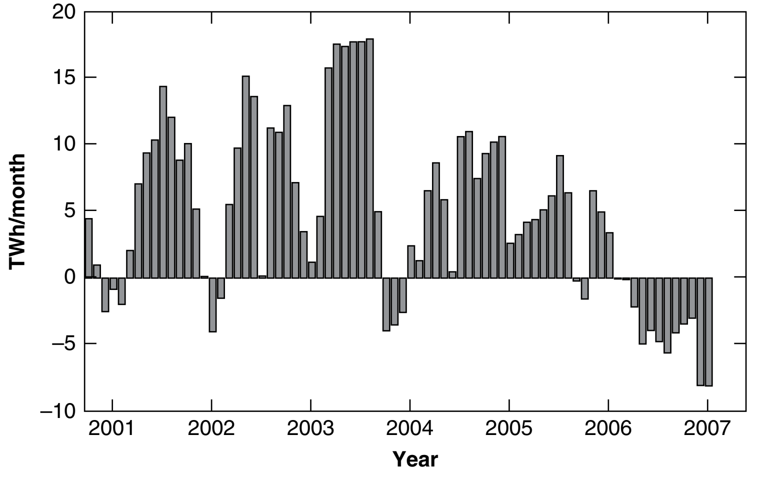

Figure 1.14 Monthly Interconnector gas flows between the UK and continental Europe. Positive values denote net exports from the UK to continental Europe. Source: http://www.interconnector.com

Since the Interconnector makes arbitrage trading possible between the UK and continental Europe (within the technical restrictions of the Interconnector), the gas spot prices at NBP and Zeebrugge are closely connected. Therefore the spread between NBP and Zeebrugge (see Figure 1.15) is most of the time near zero. However, there are short periods of time where the spread is significantly different from zero. Historically, this was regularly the case when the Interconnector was shut down due to maintenance work.

The hubs TTF and Zeebrugge are linked by a network of pipelines within continental Europe. Most of the time the spread between those hubs is therefore close to zero. In extreme situations when pipeline capacity is not sufficient to allow for further arbitrage trading between those hubs, significant spreads are observed. This was, for example, the case during the winter of the gas year 2005/2006 (see Figure 1.15). Price quotations at NBP and Zeebrugge are usually in GB pence per therm, price quotations at TTF in EUR/MWh.

The most liquid futures exchange for natural gas in Europe is ICE. ICE UK Natural Gas Futures have the following specifications:

- *Trading period*: 10–12 consecutive months, 11–12 quarters and six seasons.
- *Contract size*: Five lots of 1000 therms of natural gas per day.
- *Price quotation*: GB pence per therm.
- *Last trading day*: Two business days prior to the first calendar day of the delivery month, quarter or season.

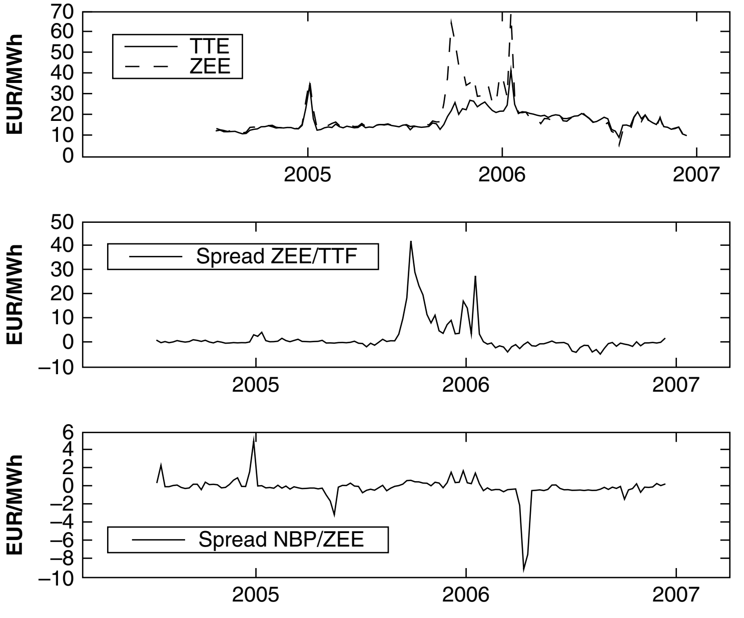

Figure 1.15 Weekly average natural gas spot prices and spreads at the main European hubs TTF, Zeebrugge (ZEE) and NBP. All prices are converted to EUR/MWh

- *Settlement type*: Physical delivery at NBP, equal delivery during each day throughout the delivery period

Besides the ICE there is a futures market for TTF natural gas at the ENDEX exchange in Amsterdam.

The Asian Market

Japan and South Korea cover most of the gas demand through LNG mainly from Indonesia, Malaysia, Australia and the Middle East. This market is dominated by long-term contracts linked to crude oil prices (see section 1.2.3). A typical formula, used in Japan, is $P = A + B \times JCC$, where A and B are constants and JCC is the *Japan Crude Cocktail*, a particular basket of crudes.

1.2.3 Price Formulas with Oil Indexation

Prior to trading natural gas in continental Europe as a commodity of its own, prices for long-term contracts were usually negotiated based on an oil price index formula. Since large investments were needed to build up a gas infrastructure, long-term contracts linked to oil prices guaranteed a long-term supply at a competitive pricing compared to oil. A typical pricing formula for natural gas in continental Europe is of the form

$$P = P_0 + A(X - X_0) + B(Y - Y_0) \tag{1.1}$$

where A and B are constants and X and Y are monthly oil quotations such as gasoil or fuel oil. Similar pricing formulas apply to the Asian market. Typically, such formulas are characterised by a triple (n, l, m):

- n is the averaging period, e.g. six months ($n = 6$).
- l is the time lag of the price fixing, e.g. $l = 1$ means that to set a price for October the averaging period ends with August.
- m is the recalculation frequency, e.g. $m = 3$ means that the oil price formula is applied every three months to set a new price for the following quarter.

An example for a scheme of type (6,1,3) is shown in Figure 1.16. The new gas price is calculated on the recalculation date and is valid for a three month period.

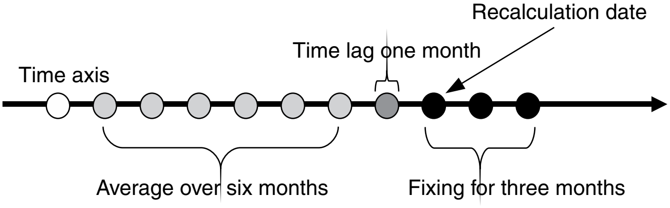

Figure 1.16 Calculation scheme of an oil price formula of type (6,1,3). On the recalculation date, the oil price is averaged over a period of six months ending one month prior to the recalculation date

Hedging the price risk of a gas contract with an oil price formula amounts to hedging an oil price risk. For this purpose the gas position can be translated into an oil position of total magnitude A times the total gas volume. The structure of the oil position over time can be rather complicated depending on the calculation scheme. An example for hedging a gas contract linked to oil prices is given in section 6.1.1.

1.2.4 Liquefied Natural Gas

To transport natural gas over long distances where pipelines are not available, liquefied natural gas (LNG) can be used. LNG is natural gas condensed into a liquid at less than $-161°$C. The density is thereby increased by a factor of about 610 to approximately 0.46 kg/l. Conversly, one (metric) tonne of LNG has a volume of 2.19 cubic metres representing 1336 cubic metres of natural gas with a heating value of 14.4 MWh. With a higher heating value of about 24 MJ/l, the energy density of LNG is comparable to the energy density of crude oil (35 MJ/l). The LNG value chain is shown in Figure 1.17. In the *LNG plant*, the natural gas is cooled down until it becomes liquid. The liquefication plants, which consist of one or more production units, cause the largest costs in the LNG value chain. A typical modern production unit has a capacity of 5 to 8 million tonnes of LNG per year. After the liquefication process, the LNG can be loaded onto special insulated *LNG vessels*. A typical LNG vessel has a capacity of about 135 000 cubic metres, but much larger vessels are under consideration. The next step in the value chain is the *regasification terminal*, where the LNG is unloaded, regasified and injected into pipelines. The main exporters for LNG are listed in Table 1.1. Total LNG exports in 2005 amounted to 189 billion cubic metres.

The infrastructure needed for production, transport and regasification is capital intensive and the value chain is costly. Therefore LNG usually cannot compete with gas transported

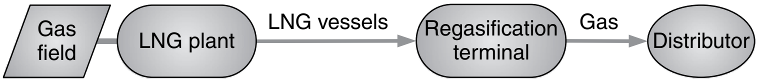

Figure 1.17 LNG value chain

Table 1.1 Main export countries for LNG in 2005. Source: Eni S.p.A. (2006)

Country	LNG exports in billion cm
Indonesia	31.5
Malaysia	28.7
Qatar	27.0
Algeria	25.7

via pipelines. Consequently, LNG has played a major role only in countries were pipelines are not available, such as Japan, South Korea or Taiwan. Most current LNG contracts are long-term contracts with prices linked to pipeline gas prices or oil prices. Take-or-pay clauses typically reduce the volume risk for the seller. Only recently, an increasing number of short-term transactions could be observed. As the currently installed global capacity for regasification terminals is much larger than the global capacity of liquefication plants, short-term transactions can exploit arbitrage opportunities by redirecting LNG vessels to those markets with the most attractive spot prices.

In the future, more and more LNG is needed to serve the growing worldwide gas demand and to replace the decreasing regional gas production in North America or Western Europe. Therefore, many new regasification terminals and LNG plants are planned or are already under construction.

1.3 THE COAL MARKET

Coal is a fossil fuel, usually with the physical appearance of a black or brown rock, consisting of carbonised vegetal matter. It is formed from plant remains that have been compacted, hardened, chemically altered, and metamorphosed by heat and pressure over geological time. It is used as a main source of fuel for the generation of electricity worldwide and for steel production. Coal is a heterogeneous source of energy, with a significantly varying quality. Coal types are distinguished by their physical and chemical characteristics. Characteristics defining coal quality are, for example, carbon, energy, sulphur, and ash content. The higher the carbon content of a coal, the higher its rank or quality. These characteristics determine the coal's price and suitability for various uses.

There are three main categories of coal. These are *hard coal*, *sub-bituminous coal* and *lignite* (also called brown coal).

Hard coal has a high gross calorific value (GCV) greater than 23 865 kJ/kg (5700 kcal/kg) and can be categorised as follows:

- *Coking coal* is a premium-grade bituminous coal at the top end of the quality spectrum used to manufacture coke for the steelmaking process.

- *Steam coal* is coal used for steam raising and space heating purposes. It includes all anthracite coals and bituminous coals not classified as coking coal. As primary fuel for hard coal fired power plants, steam coal with a calorific value greater than 23 865 kJ/kg (6000 kcal/kg) and with low moisture, ash and sulphur (less than 1%) is used.

Lignite refers to non-agglomerating coal with a GCV less than 17 435 kJ/kg (4165 kcal/kg). Sub-bituminous coal includes non-agglomerating coal with a GCV between those of hard coal and lignite. Shipping of lower quality coals is uneconomical implying that they are not trading products. These low rank coals are therefore not considered in this book.

Since coal may be classified differently, there is sometimes confusion in its classification. Some international agencies classify sub-bituminous coals as hard coal if the energy content is above 18 600 kJ/kg (4440 kcal/kg) and otherwise as lignite (cf. International Energy Agency 2004).

1.3.1 Consumption, Production and Reserves

In 2003 coal accounted for 24% of total world energy consumption. Sixty seven per cent of the produced coal was used for electricity production and 30% for industrial purposes (mainly steel production). In their International Energy Outlook 2006 (see Energy Information Administration 2006), the Energy Information Administration forecasts an increase of coal's share of total world energy consumption to 27% in 2030, while the share as primary fuel in the electric power sector remains at 41%, the same as 2003.

The total reserves of coal around the world are estimated at 909 billion tonnes. At the current consumption level total coal reserves should last approximately 180 years. Based on the consumption forecast of the International Energy Outlook 2006, and assuming that world coal consumption would continue to increase at a rate of 2.0% per year after 2030, current estimated recoverable world coal reserves should last about 70 years.[1]

Unlike oil and gas, coal reserves are more uniformly geographically distributed. The main reserves are in the United States, Russia and China. There are also significant reserves in India, Australia, South Africa, Ukraine and Kazakhstan. The geographic distribution of the total coal reserves with the differentiation between hard coal and sub-bituminous coal/lignite are shown in Figure 1.18.

Coal production is highest in China with 1107 millions tonnes oil equivalent (Mtoe) in 2005. The growing share of coal in world energy consumption can be traced back to increasing production and consumption in China.

Coal production in the United States in 2005 was 576 Mtoe, followed by Australia, India, South Africa, Russia and Indonesia. Figure 1.19 shows coal production in 2005 by region in million tonnes oil equivalent.

Coal consumption is often located in the surrounding area of its production. Because of its lower energy content compared to oil and gas, long distance overland transportation is uneconomical. In general, countries with high coal production also have high coal consumption. Consumption in China in 2005 was 1081 Mtoe. China needs coal not only for producing electricity, but also uses nearly one-half of its 2003 consumption in the industrial sector as the world's leading producer of steel and pig iron.

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[1] EIA has forecasted the growing rate of coal consumption until 2015 by 3.0% and between 2015 and 2030 by 2%.

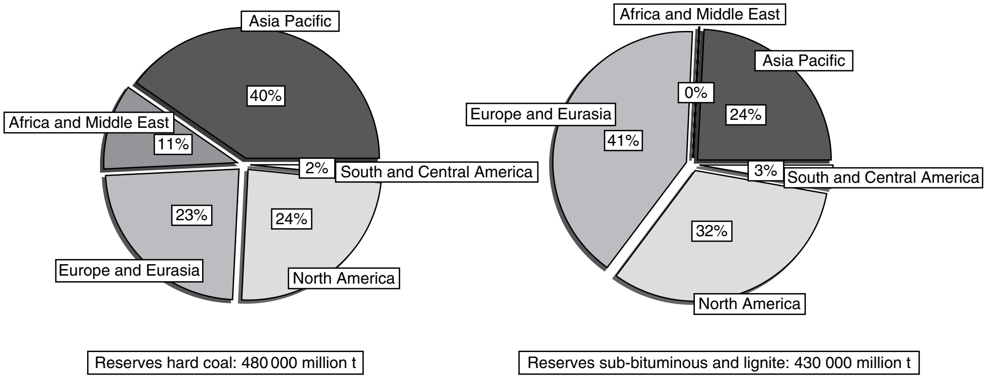

Figure 1.18 Total world coal reserves 2005 by regions. Source: BP (2006)

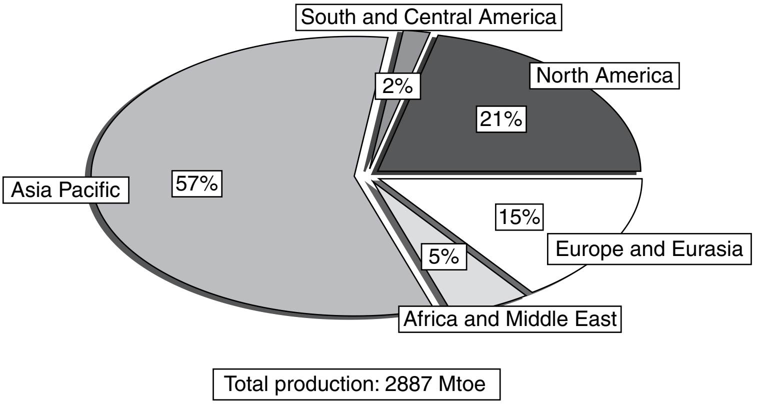

Figure 1.19 Total world coal production 2005 by regions. Source: BP (2006)

In the United States 2005 consumption was 575 Mtoe, followed by India with 212 Mtoe. Japan (212 Mtoe) and at significantly lower rates European countries like Germany and the United Kingdom have consumption exceeding their production. Australia, Indonesia, South Africa, Columbia and Russia are countries where production exceeds consumption and are net exporting nations. Coal consumption in 2005 by region is illustrated in Figure 1.20.

1.3.2 Coal Trading

The volume of international physical coal trading in 2004 was 693 million tonnes (source: EIA). In 2005, this increased to 775 million tonnes with around 90% of this being seaborne trade. Figure 1.21 shows the volume and sea routes for hard coal. There are two main trading regions, the Atlantic and the Pacific region. South Africa, Columbia and Russia are the main coal suppliers for the Atlantic region and Indonesia, Australia and China for the Pacific region. There is also a small interexchange with Australia and Indonesia supplying both the Pacific and the Atlantic region.

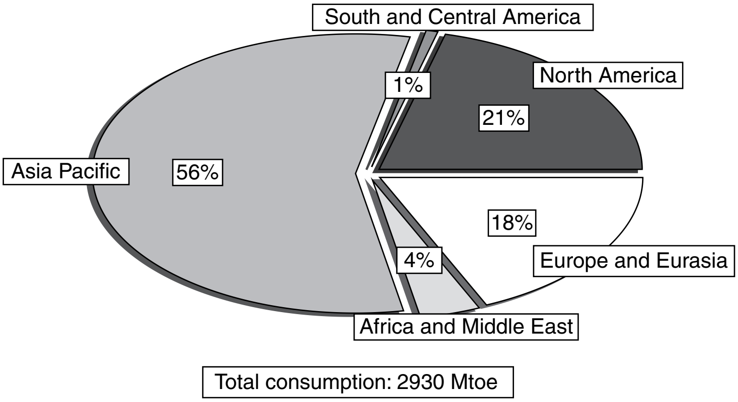

Figure 1.20 Total world coal consumption 2005 by regions. Source: BP (2006)

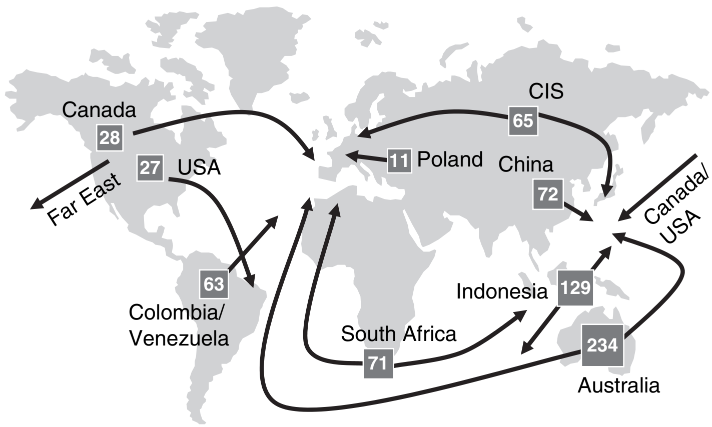

Figure 1.21 Sea routes for hard coal with transported volume. Source: Verein der Kohleimporteure (German Coal Importers Association), 2006

Producers

In the steam coal market, mergers have resulted in high market shares of some companies. The largest privately owned companies, known as the "Big Four", with a market share of approximately 35%, are:

- BHP Billiton, which was formed from a merger between BHP Ltd, Melbourne and Billiton plc, London. In 2006, BHP Billiton generated a turnover of USD 39.1 billion. BHP Billiton has investments in coal mining operations in Australia, South Africa, and Colombia.
- Rio Tinto, which is a combination of two companies: Rio Tinto plc, based in the UK, and Rio Tinto Ltd, based in Australia. Their activities span the world but are strongly represented in Australia and North America.

- Anglo American, which was formed through the combination of Anglo American Corporation of South Africa and Minorco. Anglo American has investments in coal mining operations in South Africa, Australia, and South America.
- Glencore, which also holds approximately 35% in Xstrata. Glencore has investments in coal mining operations in Colombia and South Africa. Xstrata has interests in coal mining operations in Australia, South Africa, Canada, and Colombia.

Physical Coal Prices

Because coal transportation can be expensive, in some instances it accounts for up to 70% of the delivered cost of coal, coal prices depend on the point of delivery. Standard delivery points in international coal trading are, for example, Richards Bay in South Africa, Newcastle in Australia, ARA for Central Europe or the Central Appalachian in the United States.

The characteristics defining the quality of coal also determine its price. Energy content is the most price relevant characteristic, and quoted prices per tonne (or per short ton in the USA) always refer to a specified quality and in particular to a specified energy content.

Figure 1.22 shows coal prices for the years 2004–2006 for delivery FOB Richards Bay (API#2), CIF ARA (API#4) and FOB Central Appalachian (NYMEX).[2] Both Richards Bay and the Central Appalachian are producing areas, so the price is usually quoted Free On Board. ARA is a consumer area and the price is often quoted as a CIF price. The price FOB ARA for further shipment is approximately 2 EUR/t higher. The energy content of Central Appalachian Coal corresponding to the NYMEX specification is higher than the energy content according to the API#2 and API#4 specification.

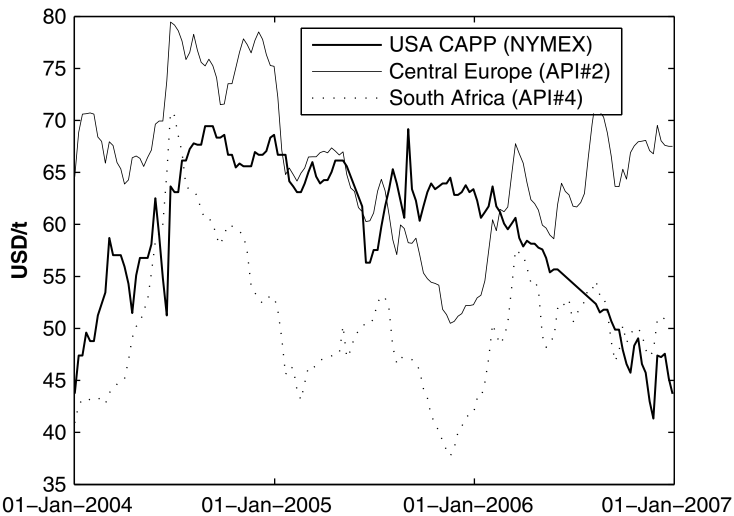

Figure 1.22 Coal prices for different regions

[2] CAPP futures contract with the nearest expiration.

Price Indices

Price information for hard coal can be obtained either from exchanges, from brokers or from independent information service providers. These include Argus Media Ltd, which offers price information, market data and business intelligence for the global petroleum, natural gas, electricity and coal industries, and the McCloskey Group, which offers data, news, and analysis focused solely on the coal industry. Price information published by the information services is typically generated via telephone or e-mail survey covering sellers of physical coal, utility buyers, trading companies and broking companies. Market analysts then assess the price of the standard specified coal that conforms to the required specification. The mechanism of price assessment must eliminate the opportunity for gaming the mechanics of the index. In contrast to an exchange, an information service has no secured information about the concluded trades.

Tradition Financial Services (TFS), a broker of OTC physical and derivative products, averages prices originally published by Argus Media and McCloskey (McCloskey's NW European steam coal marker) and has generated the well-accepted All Publications Index (API). The TFS API indices are published in the Argus/McCloskey Coal Price Index Report. There are the following API indices:

- API#2 is the index for the ARA region quoted as CIF ARA and is an important benchmark for Central Europe.[3] Delivery must be within the next 90 days, the energy content is specified at 6000 kcal/kg and the sulphur content must be less than 1%.
- API#3 is the index for FOB Newcastle, Australia. It is also a benchmark for CIF Japan prices by adding a Panamax freight assessment. Delivery must be within the next 90 days, the energy content is specified at 6700 kcal/kg and the sulphur content must be less than 1%.
- API#4 is the index for the FOB Richards Bay, South Africa, physical market. Delivery must be within the next 90 days, the energy content is specified at 6000 kcal/kg and the sulphur content must be less than 1%.

Financial Swaps

Financial swaps are the most common product for risk management for both coal producers and consumers. Because physical coal always has specific characteristics, physical coal trading is not as straightforward as trading financial swaps. The swap market is therefore particularly interesting for financial institutions, which are active market players. Financial swaps are traded usually up to three years in the future, while the time period for physical coal trading is usually shorter.

Marketplaces

Most coal trades are OTC trades. There are several exchanges that offer coal as a trading product, but the traded volume at some smaller exchanges is low.

At *NYMEX*, coal futures for the months of the current year plus the months in the next two calendar years are traded. These Central Appalachian (CAPP) coal futures are a benchmark

[3] The former API#1 index (CIF ARA) has been replaced by the more accepted API#2.

for coal prices in the United States. Delivery is to be made FOB buyer's barge at seller's delivery facility on the Ohio and Big Sandy River District, with all duties, entitlements, taxes, fees, and other charges imposed prior to delivery paid by the seller. The specified energy content is 12 000 Btu/pound (approximately 6700 kcal/kg) with a sulphur content of less than 1%.

The *Intercontinental Exchange* (ICE) offers Rotterdam coal futures contracts, which are financially settled, based on delivery to Rotterdam in the Netherlands. It is cash settled against API#2. ICE also offers Richards Bay coal futures, financially settled against API#4. Both are offered for six consecutive months, six consecutive quarters, five consecutive seasons and two consecutive calendar years. The traded volume for some of these products is low.

GlobalCOAL is a broker platform for physical coal for the important markets like Richards Bay, ARA, Newcastle and Puerto Bolivar in Colombia. It is also a marketplace for swaps on API#2 and API#4. A specified master agreement, the Standard Coal Trading Agreement (SCoTA), has to be used.

1.3.3 Freight

The delivery price of coal is determined in part by ocean freight rates. They are an important factor for the price of coal in different regions and the competitiveness of coal against other fuels. The main factor that will affect the future movement of freight rates is the overall development of dry bulk trade.

Mainly Cape and Panama sized vessels are employed in international coal trading. Cape sized vessels, used, for example, for the route Richards Bay to ARA, are also employed in the iron ore trade. As the shipping capacity is limited, the activity of the world's steel industry has an impact on coal freight rates. The other trade that can have an impact on coal freight rates is grain shipment, which is carried out predominantly in Panamax vessels. For both the export of grain and the import of iron ore, China's economy is an important factor. Figure 1.23 shows the volatility of ocean freight costs.

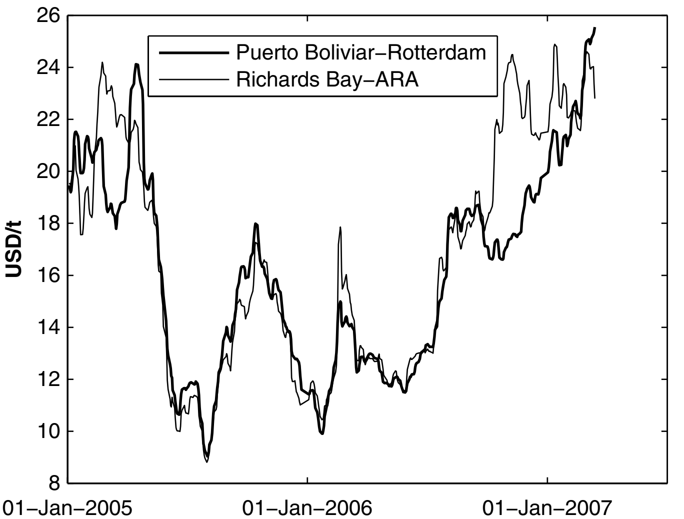

Figure 1.23 Prices for ocean freight (Capsized vessels)

1.3.4 Coal Subsidies in Germany: BAFA-Indexed Prices

In Germany the Federal Office of Economics and Export Control (Bundesamt für Wirtschaft und Ausfuhrkontrolle, BAFA) grants subsidies for German coal mining, promoting the sale of German hard coal to power stations and the steel industry. The aim of these grants is to compensate for the difference between the production costs in Germany and the coal prices of third countries. BAFA fixes the parameter for grants after checking the production costs and publishes the prices of third countries for steam coal and coking coal free German border in the BAFA index. The BAFA index may differ from the spot price (e.g. measured as API#2 price) because the import prices used for determining the BAFA index are reported when the coal is passing the German border. Since most of the contracts are concluded long before delivery, these coal import prices are a mix of forward contract prices concluded at different points of time but with the same delivery date. Imported coal is usually priced in USD, and the foreign exchange rate used for translation in Euros by BAFA is the average spot rate at the month of delivery to the German border. Hedging of BAFA-indexed contracts is difficult. While API#2 swaps are a common trading product, there is no liquid market for BAFA swaps.

1.4 THE ELECTRICITY MARKET

Electricity is a form of energy used for a very wide range of applications. It is easy to control, non-polluting at the location of its usage and convenient; it is used in the application of heat, light and power. As a secondary energy source electricity is generated from the conversion of other energy sources, like coal, natural gas, oil, nuclear power, hydro power and other renewable sources. This implies that electricity markets and electricity prices are fundamentally linked to markets for primary fuels and environmental conditions. To understand the electricity market and price mechanisms it is essential to consider the electricity generation process as well as the fuel markets. This section gives an introduction to the electricity market, to main market places and to wholesale products. Technical background information as well as energy economical modelling approaches can be found in Chapter 4.

1.4.1 Consumption and Production

Electricity is a growing market, even in proportion to the world energy markets. In 1973 electricity consumption accounted for 11% of the total world energy demand and has grown to 18% today. The absolute growth rate of electricity consumption in the future is estimated at an average of 2.7% per year. In the year 2003, world energy consumption was 14 781 TWh[4] and the financial volume of the world's physical consumption can be valued at more than USD 1000 billion per year. The projected growth in electricity consumption published by the Energy Information Administration (EIA)[5] is shown in Figure 1.24. Projected growth in net electricity consumption is most rapid among the non-OECD economies of the world. China leads the absolute growth in annual net electricity consumption with projected increases of 4300 TWh until 2030 followed by the United States with an increase of 1983 TWh.

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[4] 1 terawatthour = 1 billion kilowatthour.
[5] Source: EIA, System for the Analysis of Global Energy Markets (2006).

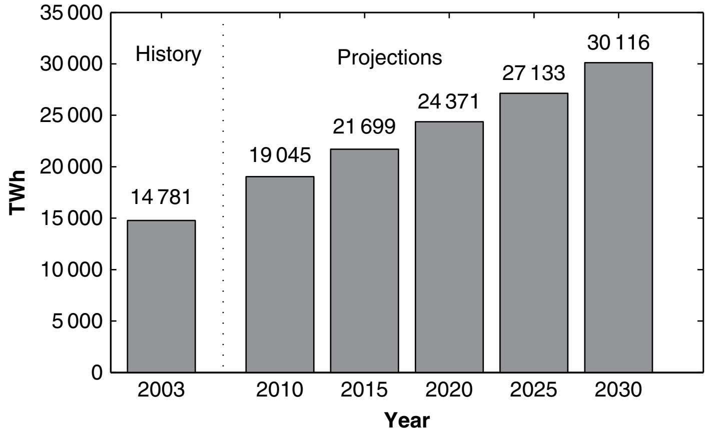

Figure 1.24 World net electricity consumption. Source: EIA

Today's electricity demand and mode of generation for different countries is illustrated in Table 1.2. Demand is highest in the United States with 3640 TWh in 2004 and per capita consumption is twice as high as in comparable European countries. Only in a few small countries with a particular type of generation and demand structure is the per capita consumption higher than in the United States. For example, in Norway 99% of the electricity generation capacity is hydro power, which results in competitive prices while the aluminium

Table 1.2 Net consumption and generation by fuel type in 2004

Country	Net Consumption (TWh)	Production according to primary fuels				
		Coal and lignite (%)	Nuclear (%)	Gas and oil (%)	Hydro (%)	Others (%)
Australia	199	79	0	13	7	1
Austria	58	14	0	20	61	5
Belgium	81	13	55	27	2	2
Canada	503	17	15	9	57	2
Czech Republic	54	60	31	5	3	1
Denmark	33	46	0	29	0	25
Finland	83	27	26	16	18	13
France	416	5	78	4	11	1
Germany	513	44	24	23	4	6
Ireland	23	30	0	63	4	3
Italy	296	17	0	58	16	8
Japan	966	27	26	35	10	2
Mexico	170	11	4	70	11	4
Netherlands	103	26	4	63	0	7
New Zealand	35	10	0	17	65	9
Norway	110	0	0	0	99	1

Poland	100	93	0	4	2	1
South Africa	197	92	5	0	2	0
Spain	231	29	23	28	12	8
Switzerland	56	0	41	2	54	3
Turkey	120	23	0	46	31	0
United Kingdom	340	34	20	42	2	2
United States	3640	50	19	21	7	2

Source: EIA.

industry and use of electricity for heating yields the highest per capita consumption of 24 000 kWh/p.a.

Prices for Electricity

The price for electricity is determined mainly by the fuels used for generation. Price drivers and the market equilibrium price are analysed in Chapter 4. The mix of primary fuels varies from country to country, which means that the variable operation costs also differ. Table 1.3 shows the electricity prices for a yearly baseload contract, which is a common trading product and a price benchmark for retail customers.

Table 1.3 Comparison of wholesale electricity prices

Country	Price for baseload 2008 in the middle of February 2007 (EUR/MWh)
Belgium	51.44
France	48.23
Germany	50.40
Netherlands	53.17
Scandinavia (Nord Pool)	39.10
United Kingdom	47.38
United States (PJM)	45.35

Figure 1.25 illustrates the development of the yearly baseload contract prices.

Prices for industrial customers are illustrated in Table 1.4 and are close to wholesale prices for the underlying load profile. Differences are mainly due to taxes and further state caused costs. At production, variable operation costs are lowest for hydro power plants. Usually marginal costs and not full costs determine electricity prices and therefore countries like Norway with a high percentage of hydro generation have low electricity prices.

In the United Kingdom, coal and gas are the usual primary fuels, implying that the price for electricity is gas price sensitive. It also depends on the price for CO_2 emission allowances. If the price for emission allowances rises there will be a fuel switch to gas fired plants, because a coal fired plant emits more CO_2 per MWh than a gas fired one. With 78% production from nuclear plants, France has also a specific mix of primary fuels. France exports to Germany, Italy, the United Kingdom, Switzerland, Belgium and Spain. These exports influence the electricity prices to these countries.

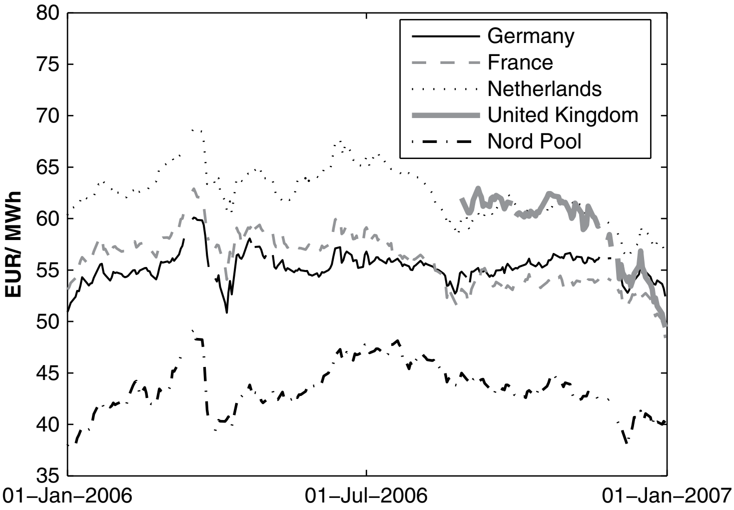

Figure 1.25 Comparison forward contract price for baseload 2008

Table 1.4 Electricity prices for industry

	Electricity prices for industry (EUR/MWh)		
Country	2000	2004	2005
Australia	45.20	60.90	*n.a.*
Austria	38.20	95.80	101.70
Belgium	47.70	*n.a.*	*n.a.*
Canada	38.50	49.00	*n.a.*
Czech Republic	43.00	66.20	80.60
Denmark	57.70	95.90	*n.a.*
Finland	38.60	72.00	70.40
France	35.80	49.80	49.80
Germany	40.60	76.90	*n.a.*
Ireland	48.90	95.70	99.40
Italy	88.90	161.50	*n.a.*
Japan	143.20	127.20	*n.a.*
Mexico	50.90	77.50	87.80
Netherlands	57.10	*n.a.*	*n.a.*
New Zealand	28.00	51.00	54.70
Norway	19.40	43.30	43.40
Poland	36.90	60.10	69.90
South Africa	17.20	*n.a.*	*n.a.*
Spain	42.60	59.90	83.30
Switzerland	69.10	85.40	83.30
Turkey	80.00	100.10	106.60
United Kingdom	55.40	66.70	86.00
United States	46.40	52.50	57.30

Energy end-use prices including taxes, converted in Euros.
Source: EIA November 2006.

1.4.2 Electricity Trading

For many commodities there is an intuitive answer to the question "What is the real trading product?" But for electricity the answer to this question requires further understanding of the technical background.

Among all commodities electricity has the unique feature that it is not storable. An exception are hydro pumped storage power plants, but in most countries their capacity is small compared to total consumption. The second main feature is the necessity for a transmission network, which prevents a global market. These characteristics of electricity shown in Figure 1.26 have strong implications on the trading products and their prices. An often discussed characteristic resulting from the non-storability is the high volatility of power prices, but these high price movements refer to products with a nearby delivery. In the absence of sufficient economical generation capacity, non-storability causes high price movements on the spot market. In the forward market with delivery dates in the far future the price movements are much smaller, because the availability of power plants and weather dependent demand are still unknown.

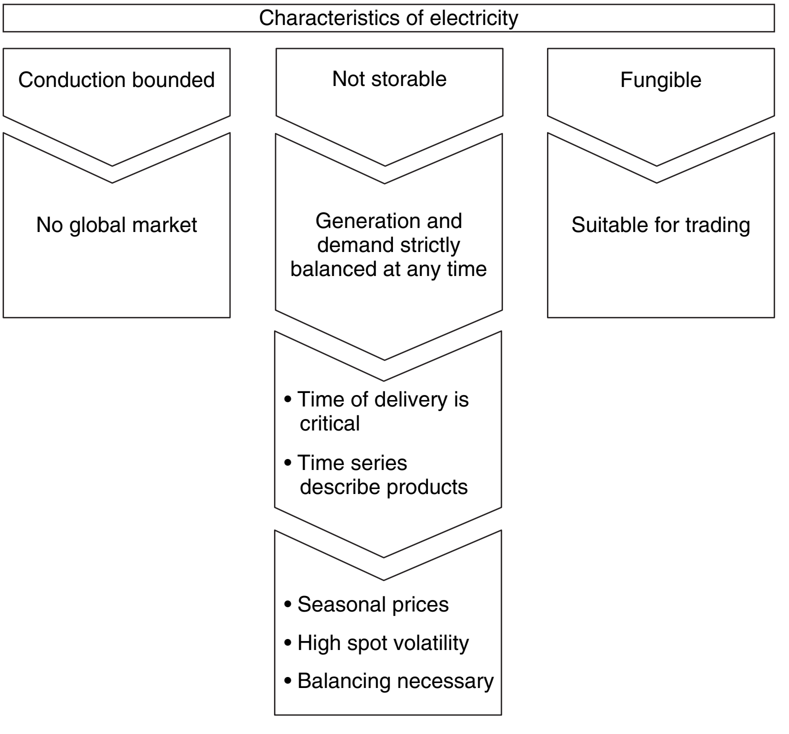

Figure 1.26 Characteristics of electricity

The lack of storability requires an exact matching of supply and demand at all times. Because a merchant cannot forecast the demand of his customers exactly there must be someone responsible for balancing supply and demand. This is a task of the transmission system operator (TSO), who charges the merchant directly or the retail customers via transmission fees for this service. The TSO defines a balancing period (e.g. 30 minutes in the UK, 15 minutes in Germany), which is the granularity of the measured electric energy supply. The continuously varying power requirements of retail customers is integrated over the balancing period and the average power is the size which is forecast and should be delivered by the supplying merchant. As a result, the merchant delivers energy as a discrete time series with time steps according to the balancing period and constant power during these time periods. Figure 1.27 illustrates the continuously varying power requirement (load profile) and the piecewise constant delivery of power during the balancing period.

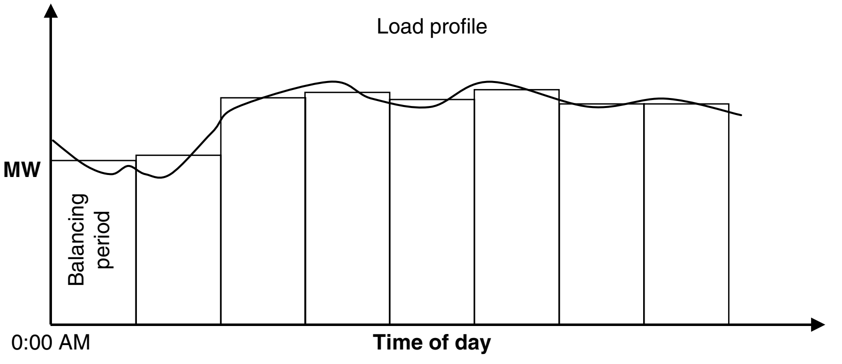

Figure 1.27 Balancing period

1.4.3 Products in the Electricity Markets

The principal products in the electricity markets are delivery time series in a granularity not finer than the balancing period. The usual granularity is one hour and in this book this granularity is assumed if not stated otherwise. Power balancing during the balancing period itself is the task of the TSO. Since the TSO usually has no personal generation capacities he has to purchase products that allow an increase or decrease in production (including import and export) in his transmission system. In this section the main features of products in the electricity market are described. As there is no global market for electricity, the products in regional markets may differ.

The electricity market can be divided into the following categories:

- *Forward and futures market*: The forward and futures market is the relevant market for risk management and serves the participants to hedge their positions. It is also the relevant market for speculation and pure trading purposes. The agreed delivery or acceptance period of these products includes dates later than the next trading day.
- *Day ahead market*: In the day ahead market products are traded which are delivered the next day. If the next day is not a trading day the day ahead market also includes products delivered between the next day and the next trading day. Day ahead products are the most common spot products and can be traded either on a power exchange or as a bilateral agreement. Day ahead products are the underlyings of the futures contracts on the power exchange.
- *Intra-day market*: The intra-day market is for products with a delivery on the same day. This market allows the producers a short-term load dependent optimisation of their

generation. Because this market serves the direct physical supply it is not a market for pure trading purposes. Intra-day products are traded either on a power exchange or bilaterally.
- *Balancing and reserve market*: There are different definitions of the terms balancing market and reserve market, because these markets depend on a regulator and are country specific. In the context of this book the *reserve market* is the market allowing the TSO to purchase the products needed for compensating imbalances between supply and demand in the electricity system. The *balancing market* (also referred to as real-time market) denotes the market where a merchant purchases or sells the additional energy for balancing his accounting grid. This is the service of the TSO who charges or reimburses the merchant for the additional energy, and only in some national markets is the merchant able to buy or sell this balancing energy from or to someone else. So the balancing market can be regarded as a market only in a broad sense.

The different market categories and their time flow are described in Figure 1.28.

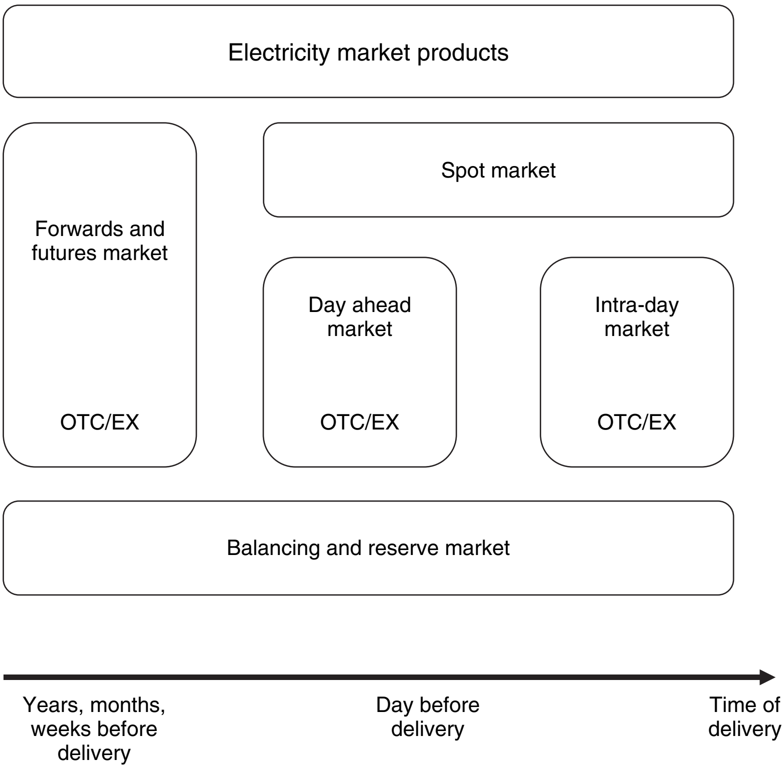

Figure 1.28 Categories of the electricity market

Outside the balancing and reserve market, products in the electricity market can be described by time series. Usually the granularity of the time series is one hour and then each number of the time series specifies the constant power delivered in the corresponding hour. If the delivered power is constant over the delivery period $[T_1, T_2]$ the contract is called a *baseload contract*. If the constant power is delivered only is constant in those predefined hours of the delivery period when the consumption is high the contract is called a *peakload contract*. Peakload hours depend on the particular market. For example, at the New York Mercantile Exchange (NYMEX) peakload hours are the hours 7:00 am to 11:00 pm and in France and Germany the hours are 8:00 am to 8:00 pm on peakload days. Peakload days at NYMEX are Monday–Friday, excluding specified holidays, while in France and Germany they are Monday–Friday including public holidays.

Forward Market

Forwards can be divided into standard forwards and individual power schedules. Standard contracts are baseload or peakload contracts whose delivery period is a day, week, month, quarter or year. Individual schedules are delivery schedules, whose power can vary every hour or even every balancing period (e.g. every 30 minutes in the UK). Figure 1.29 shows a baseload contract, a peakload contract, and an individual schedule, where the delivery period is one week.

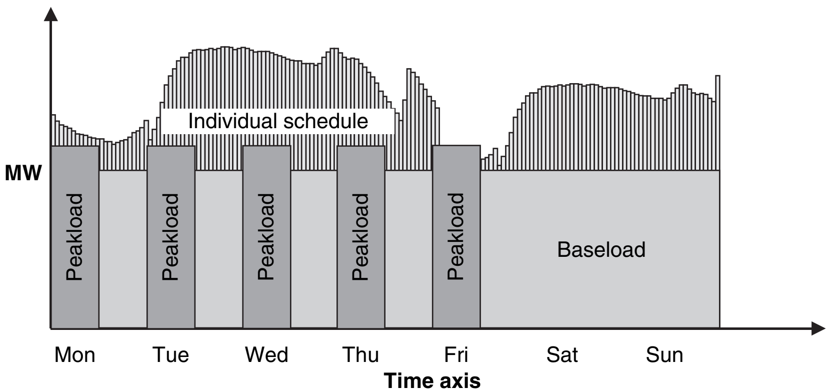

Figure 1.29 Delivery hours of a baseload, a peakload and an individual schedule contract with a delivery period of one week

In some markets there are efforts to standardise further products. These can be block contracts, implying a delivery with constant power on defined dates and defined hours during the delivery period (e.g. on every weekend during the delivery period of a week, month or year). There are also standardised load profiles representing certain physical load patterns. An example is the GH0 profile traded in Germany, which is based on a standardised load profile for households and is scaled up to a tradable size of 10 GWh/a. The delivery period is one calendar year.

Futures Market

As usual for every futures contract (see section 2.1.2) electricity futures are subject to a daily margining. As electricity futures contracts do not have a single delivery date but a delivery period, there must be mechanism to calculate the variation margining during the delivery period. Often contracts with a long delivery period (e.g. a year or a quarter) are split into futures contracts with a shorter delivery period (e.g. a quarter or a month). This procedure is called cascading and is shown in Figure 1.30. In this example the yearly futures contract cascades into three monthly futures contracts and into the three remaining quarterly futures contracts. Later, the quarterly contracts cascade into monthly contracts. The final settlement price of a monthly future is then established from the average of the associated spot market prices.

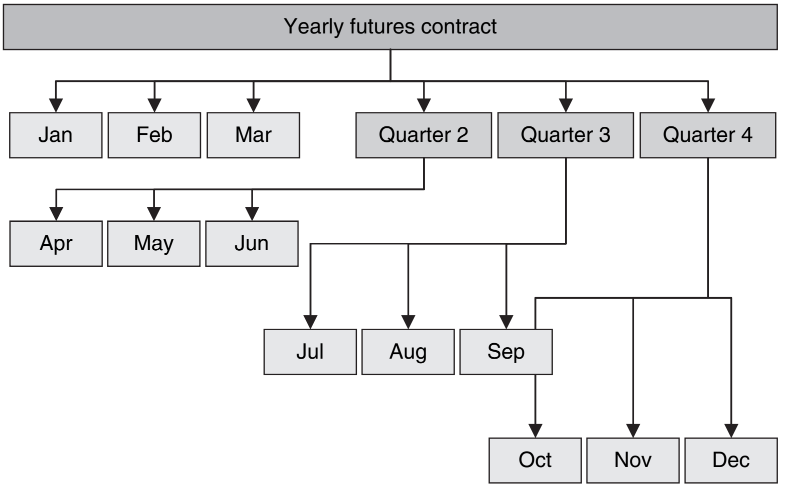

Figure 1.30 Cascading of a yearly futures contract

Spot Market (Day Ahead and Intra-Day Market)

Spot products are traded OTC as well as on power exchanges. The term of payment on an exchange is often shorter than for OTC contracts. Standard products are baseload and peakload contracts with a delivery period of one day. In addition there are hourly contracts and block contracts. Hourly products are traded on the spot market only and are the basis for the pricing of many other products. In the case of block contracts the delivery of electricity with a constant power over several delivery hours is traded. The spot market is the underlying for the forward and futures market.

Balancing and Reserve Market

While forwards and futures markets have a comparable structure in different regions, the balancing and reserve markets are affected by national regulation, which defines the role of the TSO. In the United States the system operators are public utilities regulated by the individual states and FERC.[6]

There are also international associations that secure the interconnected power systems. In Europe the European Transmission System Operators (ETSO) was created in 1999, as an association with the following founding members:

[6] Federal Energy Regulatory Commission.

- UCTE, the Union for the Coordination of Transmission of Electricity, TSOs of the continental countries of Western and Central Europe.
- NORDEL, the association of Nordic TSOs.
- UKTSOA, the United Kingdom TSO Association.
- ATSOI, the association of TSOs in Ireland.

Today, ETSO involves almost every TSO in Europe, with networks supplying more than 490 million people with electricity.

A change in frequency indicates to the TSO a shortage or a surplus of energy in the system. Physically, this means that there is a deceleration or acceleration of the turbines because their kinetic energy balances consumption and generation. For stabilising the transmission system this frequency deviation must be equalised. Therefore technical and organisational rules have been developed.

For example, the rules for the UCTE system in continental Europe are referred to in the *UCTE Operation Handbook*. The *UCTE Operation Handbook* includes a description of generation control actions. The control actions are performed in different successive steps, each with different characteristics and qualities, and all depending on each other.

- *Primary reserve*: After a disturbance the primary reserve (also called primary control) starts within seconds as a joint action of all TSOs in the synchronised transmission system.
- *Secondary reserve*: The secondary reserve (also called secondary control) replaces the primary reserve after a few minutes and is put into action by the responsible TSOs only.
- *Tertiary reserve*: The tertiary reserve (also called tertiary control or minute reserve) frees the secondary reserve by rescheduling generation and is put into action by the responsible TSOs.

The sequence of the different control actions is displayed in Figure 1.31.

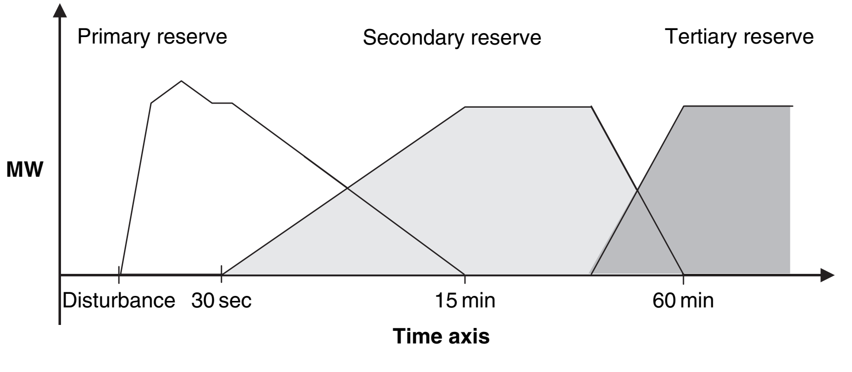

Figure 1.31 Control actions in the UCTE system

The products in the reserve market are derived from these control actions. The TSO tenders the products it needs for fulfilling these functions. In contrast to forwards, futures or spot products, the reserve market products are more technical and refer to specified plants. These plants must be able to reduce or increase production at short notice. While for most other electricity products only energy delivered is payed for, reserve energy products involve often an additional payment of the reserved capacity.

The prices for balancing power are usually prices for the delivered energy only. For the merchant this is often additional cost which is analysed in section 5.5. Prices for balancing power differ widely and are only sometimes related to spot or futures market prices. The relation of the balancing and the spot market in the Netherlands is studied in Boogert and Dupont (2005).

1.4.4 Energy Exchanges

Energy exchanges are major marketplaces for electricity. In recent years more and more countries have founded exchanges for electricity. Some of them are only a marketplace for spot products, but the major exchanges are characterised by the existence of a derivative market with a high trading volume. Most electricity exchanges are located in Europe and North America. The map in Figure 1.32 shows the location of some electricity exchanges worldwide.

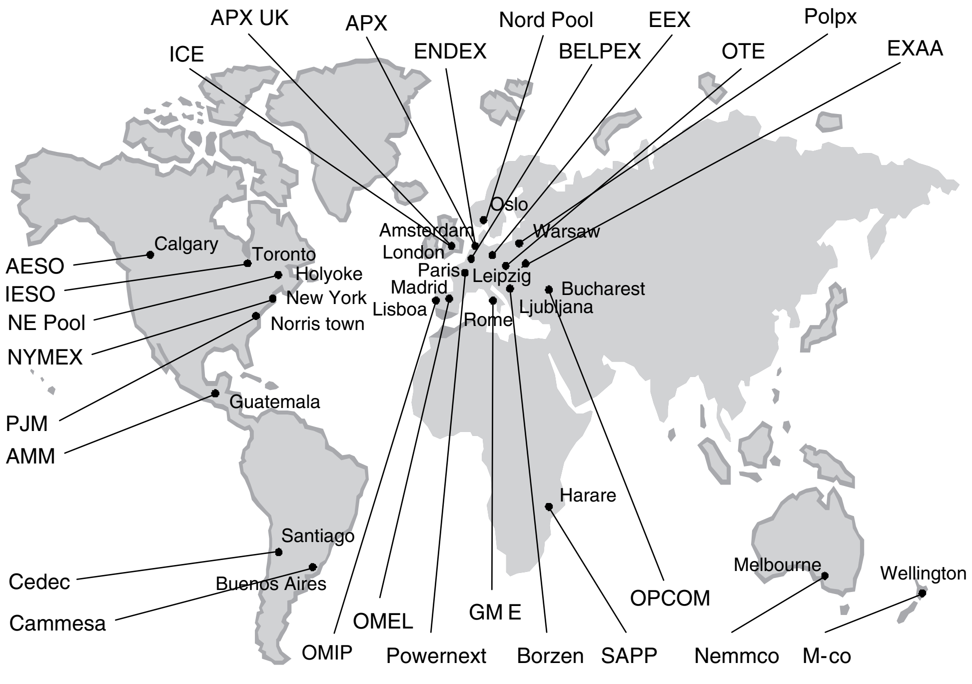

Figure 1.32 Locations of exchanges trading electricity

In this section some of the major exchanges are discussed in more detail.

Nord Pool

Nord Pool is a multinational exchange for trading electricity in Northern Europe. It was founded in 1993 initially as the Norwegian market for physical contracts, as a result of the deregulation of the Norwegian electricity market in 1991. In 1996 the joint Norwegian–Swedish power exchange commenced, the world's first multinational exchange for trade in power contracts. Subsequently Finland and Denmark joined the Nordic power exchange market area. In 2006 the traded volume in the physical market (Elspot) was 250 TWh and there were 294 registered participants. The volume in the financial market was 766 TWh and together with the clearing volume of the OTC market there is a total volume of 2160 TWh with a value of approximately 79 billion Euros. This total trading volume exceeds by far the generation of approximately 370 TWh in Norway, Sweden, Finland and Denmark.

At the Nord Pool there are three product groups:

- Physical market.
- Financial market.
- Clearing service.

Physical Market – Nord Pool Spot AS

Nordic market participants trade power contracts for next day physical delivery at the Elspot market. This day ahead trading is based on an auction trade system. Bids for purchase and sale of power contracts of one-hour duration cover all 24 hours of the next day. Three bidding types are available, namely hourly bids, block bids, and flexible hourly bids. As soon as the noon deadline for participants to submit bids has passed, all buy and sell orders are gathered into two curves for each power-delivery hour: an aggregate demand curve and an aggregate supply curve. The spot price for each hour is determined by the intersection of the aggregate supply and demand curves. This spot price is also called the system price. Since Nord Pool is a multinational exchange, possible grid congestions require a partition into separate bidding areas. Separate price areas occur if the contractual flow between bidding areas exceeds the capacity allocated by TSOs for spot contracts. If there are no such capacity constraints, the spot system price is also the spot price throughout the entire Nordic Power Exchange Area.

After the publication of the Elspot results there is a physical intra-day market called *Elbas* for the areas Eastern Denmark, Finland and Sweden. The Elbas market is based on hourly contracts and provides continuous power trading 24 hours a day, up to one hour prior to delivery.

Financial Market

The Nord Pool offers a liquid financial market for price hedging and risk management with a time horizon of up to four years. The market consists of futures, forwards, options and contracts for differences.

Futures contracts consist of standardised day and week contracts. Weeks are listed in a continuous cycle of eight weeks. The settlement of futures contracts involves a daily marked-to-market settlement and a final spot reference cash settlement after the contract reaches its due date.

Nord Pool uses a slightly modified definition for the term *forward contract*. In the context of this book and consistent with the definition in many publications (e.g. Hull 2005) the term forward is used for OTC trades, which implies that there is no marked-to-market settlement. Nord Pool uses the term forward for their particular exchange products with no marked-to-market settlement in the trading period prior to the due date. The marked-to-market is accumulated as daily loss or profit but not realised throughout the trading period.

During the delivery period the difference between the price when the contract was entered into and the spot reference price will be cleared.

Nord Pool's forward contracts consist of monthly, quarterly, seasonal and yearly contracts. Months are listed in a continuous cycle of six months. Seasons (winter, summer) are replaced by quarters. Years cascade into either seasons or quarters, and quarters cascade into months.

Market participants who use financial market derivatives to hedge spot market prices remain exposed to the risk that the system price will differ from the actual area price of their spot purchases or sales. To overcome this potential price differential risk Nord Pool offers a forward contract product named *Contracts for Difference*. The liquidity of these contracts is sometimes insufficient.

Options contracts traded at Nord Pool use standard forwards as the underlying contract. The option contracts are European style, i.e. they can only be exercised at the exercise date. Options with new strike prices are automatically generated to reflect price movements of the underlying forward instrument.

Nord Pool Clearing also clears contracts traded in the bilateral financial markets that are registered for clearing. To be accepted for clearing a bilateral market electricity contract must conform to the standardised products traded at Nord Pool. This clearing service reduces clearing members' counterparty risk.

European Energy Exchange

The European Energy Exchange (EEX) is located in Leipzig, Germany, and is the leading exchange for electricity in Central Europe. Preceding companies were Leipzig Power Exchange started in 2000 and European Energy Exchange started in 2001. Both exchanges and their supporting associations merged in 2002. In 2006 the total traded volume in the physical spot market was 89 TWh and in the futures market, including OTC clearing, was 1044 TWh. The traded volume clearly exceeds the total consumption in Germany of approximately 540 TWh. At the EEX the product groups are:

- Power spot market.
- Power futures and options.
- Coal futures and EU emission allowances.
- Clearing service.

Power Spot Market

The spot market at the EEX includes a day ahead and an intra-day market. At the day ahead market there is a continuous trading of baseload, peakload and weekend baseload contracts and an auction for single hours and blocks of contiguous hours. Besides a delivery in the grid of the four German TSOs there is also an auction for delivery in the Austrian Power Grid and in the Swissgrid. In the intra-day market full hours and blocks of contiguous hours can be traded with physical delivery in the four German TSO areas. This service offers continuous trading 24 hours a day, seven days a week.

Power Futures and Options

At the EEX futures contracts with financial and physical settlement are traded. The underlying of the financially settled futures contracts is the EEX spot market index Phelix. The settlement of futures contracts involves a daily marked-to-market settlement. Yearly and quarterly futures are fulfilled by cascading, this process is displayed in Figure 1.30. Traded products are baseload and peakload futures for the next six calendar years, the next seven quarters, the current and six following months.

At the end of a month the last payment for monthly futures is established on the basis of the difference between the final settlement price and the settlement price of the previous exchange trading day. The final settlement price is established from the average of the associated EEX spot market prices.

Additionally there are futures contracts with a physical settlement available both in Germany and in France. These contracts are also subject to a daily marked-to-market settlement. The traded volume of these futures is much smaller than those for the financially settled futures.

EEX offers European-style options, i.e. the options can only be exercised on the last day of trading. The underlyings are the financially settled futures. More specifically, options on the respective next five baseload monthly futures, the respective next six baseload quarterly futures and the respective next three baseload yearly futures can be traded. The liquidity of the EEX options market has so far been very low.

EEX offers a well-accepted *clearing service* for OTC trades. The volume of OTC clearing is comparable to the volume of the traded futures. OTC transactions corresponding to available EEX futures or options can be registered by means of a so-called EFP (Exchange Futures for Physical) trade for OTC clearing.

New York Mercantile Exchange

After a delisting in 2002 NYMEX takes a novel approach to the relaunch of electricity futures. The new contracts are PJM electricity futures which have the PJM spot market as an underlying. PJM Interconnection LLC administers more than 44 million customers in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and Washington, DC. This generation and distribution network is also tied to the power grids of the Midwest, New York State, and other areas in the mid-Atlantic states.

NYMEX provides financially settled monthly futures contracts for peakload and off-peakload electricity transactions based on the daily floating price for each day of the month at the PJM western hub. The underlying price of these monthly futures is the arithmetic average of the PJM western hub real-time locational marginal price (LMP) for the peak and off-peak hours of each day provided by PJM Interconnection LLC. The PJM western hub consists of 111 delivery points, primarily on the Pennsylvania Electric Co and the Potomac Electric Co utility transmission systems.

There are monthly futures contracts for the current year plus the next five calendar years. A new calendar year will be added following the termination of trading in the December contract of the current year. Further trading products are options on the PJM monthly futures contracts.

Intercontinental Exchange

ICE electricity futures contracts are deliverable contracts where each clearing member with a position open at cessation of trading for a contract month is obliged to make or take delivery of electricity to or from National Grid Transco, United Kingdom. ICE offers UK baseload and peakload electricity futures for the next 12 months, six quarters and four seasons.

1.5 THE EMISSIONS MARKET

Global warming caused by the greenhouse effect is one of the key environmental challenges of the 21st century. The greenhouse effect itself is caused by the property of certain gases in the atmosphere to absorb and reflect thermal radiation of the earth's surface back to the earth. The natural greenhouse effect is mainly caused by water vapour (H_2O), carbon dioxide (CO_2), ozone (O_3), nitrous oxide (N_2O), and methane (CH_4). Without the natural greenhouse effect the average surface air temperature would be $-20°C$ instead of $+15°C$.

Increased concentrations of greenhouse gases in the atmosphere caused by human activities are responsible for the anthropogenic greenhouse effect. Since the beginning of the 20th century the average air surface temperature increased by 0.6°C and the UN Intergovernmental Panel on Climate Change (IPCC) has projected a further increase by 1.4°C to 5.8°C until 2100. Climate change has had a severe impact on the environment including raising sea levels, threatening coastal communities, increasing the frequency of extreme weather events, storms, draughts, floods, and extinction of endangered species (European Commission 2005a).

1.5.1 Kyoto Protocol

Since the 1970s climate change has been on the political agenda. The first World Climate Conference with scientific focus was organised in 1979 in Geneva. It issued a declaration calling on the world's governments "to foresee and prevent potential man-made changes in climate that might be adverse to the well-being of humanity". The declaration also identified increased atmospheric concentrations of carbon dioxide resulting from utilisation of fossil fuels, deforestation, and changes in land use as main causes of global warming. The conference led to the establishment of the World Climate Programme, to a series of intergovernmental climate conferences and in 1988 to the establishment of the International Panel on Climate Change (IPCC) by the United Nations Environment Programme (UNEP) and the World Meteorological Organisation (WMO). Organised in three working groups, the IPCC prepares assessment reports on available scientific information on climate change, environmental and socio-economic impacts of climate change, and formulation of response strategies. Based on the first IPCC reports published in 1990, the United Nations General Assembly decided to initiate negotiations on an effective framework convention on climate change. The United Nations Framework Convention on Climate Change (UNFCCC) was opened for signature at the United Nations Conference on Environment and Development in Rio de Janeiro in 1992 and entered into force in 1994.[7] Signatories of the UNFCCC have different responsibilities:

- *Annex I countries*: Industrialised countries who have agreed to reduce their greenhouse gas emissions.
- *Annex II countries*: Developed countries who are responsible for bearing the costs of climate change mitigation in developing countries. Annex II countries are a subset of Annex I countries.
- *Developing countries*: These countries have no immediate responsibilities.

[7] By 2006, the UNFCCC was ratified by 190 countries.

The UNFCCC sets a framework for climate change mitigation but does not contain greenhouse gas emission limits for individual countries. Since the UNFCCC entered into force, the parties meet annually in Conferences of the Parties (COP) to assess the progress in climate change mitigation and to negotiate legally binding targets.

The Kyoto Protocol to the UNFCCC was adapted at the 1997 COP 3 in Kyoto, Japan and entered into force in 2005. The Kyoto Protocol commits Annex I Parties to individual, legally binding targets to limit or reduce their greenhouse gas emissions. Only Parties to the Convention who have ratified the Kyoto Protocol will be bound by the Protocol's commitments. One hundred and sixty-eight countries and the European Union (EU) had ratified the Protocol by the end of 2006. Of these, 35 countries and the EU are required to reduce greenhouse gas emissions during the period 2008–2012 below levels specified for each of them (Annex B countries, which are almost identical with the Annex I countries of the UNFCCC). In total, the Annex B countries have committed to reduce their emissions by at least 5% from 1990 levels. The global warming potential of different greenhouse gases is expressed in CO_2 equivalents. Annex A specifies which greenhouse gas emissions are subject to the Kyoto Protocol:

- Carbon dioxide (CO_2).
- Methane (CH_4), CO_2 equivalents: 23.
- Nitrous oxide (N_2O), CO_2 equivalents: 310.
- Hydrofluorocarbons (HFCs), CO_2 equivalents: 140–11 700.
- Perfluorocarbons (PFCs), CO_2 equivalents: 6500–9200.
- Sulphur hexafluoride (SF_6), CO_2 equivalents: 23 900.

The CO_2 equivalent figures above refer to the 100 years time horizon (International Panel on Climate Change 2005). Furthermore, Annex A specifies sectors/source categories for emission covered by the Kyoto Protocol. Main categories are: energy, industrial processes, solvent and other product use, agriculture, and waste.

Quantified emission limits for the first commitment period, from 2008 to 2012, are specified in Annex B of the Kyoto Protocol. Base year is the year 1990. Instead of 1990, Parties may use 1995 as base year for HFCs, PFCs, and SF_6. In addition to total emissions, impacts of land-use, land-use change, and forestry (LULUCF) are considered. Emission limits and changes in emissions between 1990 and 2004 are listed in Table 1.5. Out of the Annex I countries, Australia, Croatia, Turkey, and the Unites States had not ratified the Kyoto Protocol by 2006. For Belarus and Turkey, emission limits had not been defined by 2006.

The Kyoto Protocol defines three types of "flexible mechanisms" to lower the overall costs of achieving its emissions targets: joint implementation (Article 6), clean development mechanism (Article 12), and emissions trading (Article 17). These mechanisms enable Parties to access cost-effective opportunities to reduce emissions or to remove CO_2 from the atmosphere (e.g. by afforestation) in other countries. The establishment of these flexible mechanisms acknowledges that marginal emission reduction costs can vary considerably from region to region while the benefits for the atmosphere are the same, wherever the action is taken. Flexible mechanisms are explained in more detail in section 1.5.3.

Table 1.5 Committed emission limits under the Kyoto Protocol

Emission limitation (% of base year or period) and changes in emissions without LULUCF between 1990 and 2004 (%)

Country	Limit	Change	Country	Limit	Change
Australia	108	+25.1	Liechtenstein	92	+18.5
Austria	92	+15.7	Lithuania	92	−60.4
Belarus		−41.6	Luxembourg	92	+0.3
Belgium	92	+1.4	Monaco	92	−3.1
Bulgaria	92	−49.1	Netherlands	92	+2.4
Canada	94	+26.6	New Zealand	100	+21.3
Croatia	95	−5.4	Norway	101	+10.3
Czech Republic	92	−25.0	Poland	94	−31.2
Denmark	92	−1.1	Portugal	92	+41.0
Estonia	92	−51.0	Romania	92	− −41.0
EU	92	−0.6	Russian Federation	100	−32.0
Finland	92	+14.5	Slovakia	92	−30.4
France	92	−0.8	Slovenia	92	−0.8
Germany	92	−17.2	Spain	92	+49.0
Greece	92	+26.6	Sweden	92	−3.5
Hungary	94	−31.8	Switzerland	92	+0.4
Iceland	110	−5.0	Turkey		+72.6
Ireland	92	+23.1	Ukraine	100	−55.3
Italy	92	+12.1	UK	92	−14.3
Japan	94	+6.5	United States	93	+15.8
Latvia	92	−58.5			

Source: Kyoto Protocol and UNFCCC (2006).

At annual climate conferences (COPs) following Kyoto, implementation rules for the Kyoto Protocol were negotiated.[8]

1.5.2 EU Emissions Trading Scheme

The member states of the European Union (EU-15) agreed in 1998 on a Burden Sharing Agreement. It redistributes among them the overall 8% reduction target under the Kyoto Protocol. The individual quantified emission limitation or reduction commitments for the Kyoto period 2008–2012 are listed in Table 1.6.

Only a few countries, among them Germany, the United Kingdom, France, and Sweden, were on a path to achieving their targets while other countries were expected to have emissions that significantly exceeded these targets. Overall, it was realised by the European Commission that the EU commitment under the Kyoto Protocol would not be achieved without additional measures.

The European Commission considered the introduction of an emissions trading scheme on a company level as an appropriate measure for achieving the Kyoto target. In 2003, the

[8] Detailed information on the UNFCCC, the Kyoto Protocol, and the COPs can be found on the UNFCCC Secretariat's homepage: http://unfccc.int.

Table 1.6 EU Burden Sharing Agreement targets as % of 1990 emissions

Belgium	92.5	Luxembourg	72
Denmark	79	Netherlands	94
Germany	79	Austria	87
Greece	125	Portugal	127
Spain	115	Finland	100
France	100	Sweden	104
Ireland	113	United Kingdom	87.5
Italy	93.5		

European Council formally adopted the Emissions Trading Directive (Directive 2003/87/EC). The directive describes the framework for the European Emissions Trading Scheme (EU ETS). The scheme covers the electricity and heat sector and energy intensive industrial sectors. All installations above certain size limits, e.g. rated thermal input exceeding 20 MW for combustion installations, have to participate. The EU ETS covers approximately 40% of all emissions under the Kyoto Protocol in the EU.

Only CO_2 emissions are covered in the first trading period, 2005–2007. In the second trading period, 2008–2012, other greenhouse gas emissions under the Kyoto Protocol can be covered as well. In the first trading period, the EU ETS covers all 25 member countries of the EU.

Member States are responsible for the allocation of emission allowances by means of National Allocation Plans (NAPs). Besides emissions within the EU ETS, all other emissions under the Kyoto Protocol have to be considered in order to achieve the emission targets under the Burden Sharing Agreement. Emission allowances (EUAs) are distributed to participating installations. The unit of the EUAs is 1 t CO_2. For the first trading period, at least 95% of the EUAs have to be allocated for free, for the second period at least 90%. All installations in the EU ETS have to submit EUAs for their emissions to national emissions registries. EUAs can be traded freely. Therefore, installations with emissions above their allocation can buy EUAs for their demand and installations with emissions below their allocation can sell them. Transfer of certificates from one year to the next (banking) and for one year to the previous year (borrowing) is possible within a trading period. Banking or borrowing is not possible between the first and the second trading period. But banking is possible from the second trading period to a third trading period. If the operator of an installation fails to deliver sufficient EUAs, a penalty of 40 EUR/t CO_2 for the first period and 100 EUR/t CO_2 for the second period applies and, in addition, EUAs of the next trading period have to be submitted (Schiffer 2005).

The NAPs have to be approved by the European Commission. In June 2005, the last of the 25 National Allocation Plans for the first period 2005–2007 was approved. The allocation process for the first period covered more than 10 500 installations. In total, the Commission has approved the allocation of approximately 2.16 billion allowances per year for the first trading period. Almost 80 million allowances have been put aside by Member States in new entrants reserves to allocate allowances to operators entering the market (European Environment Agency 2006). Each Member State has its own national registry containing accounts, which hold the EUAs. These registries interlink with the Community Independent Transaction Log (CITL), operated by the Commission. It records and checks every transaction. Apart from allocated EUAs for every installation, the CITL also

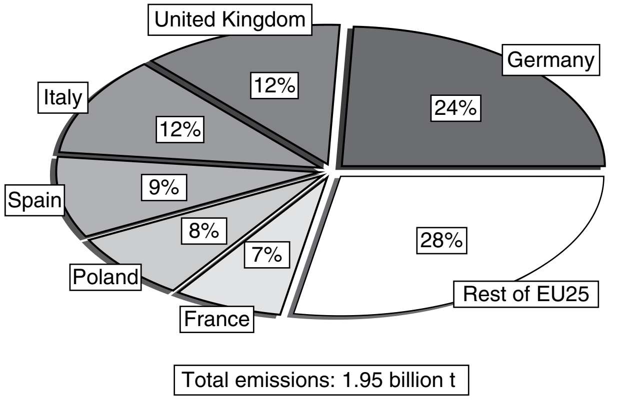

Figure 1.33 CO_2 emissions 2005 in the EU ETS by country. Source: CITL, February 2007

contains information on verified historic emissions for previous years for every installation. Figure 1.33 shows the distribution of historic emissions by country. Four countries, Germany, the United Kingdom, Italy, and Spain, are already responsible for more than 50% of all emissions covered by the EU ETS, and half of the countries are responsible for more than 90%.

CITL emission data allows the classification of emissions by activity. Categories and their total certified emissions 2005 are (CITL, February 2007):

Energy activities

- Combustion installations with a rated thermal input exceeding 20 MW (excepting hazardous or municipal waste installations): 1,380 Mt CO_2 or 71% of all emissions.
- Mineral oil refineries: 150 Mt CO_2 or 8%.
- Coke ovens: 20 Mt CO_2 or 1%.

Production and processing of ferrous metals

- Metal ore (including sulphide ore) roasting or sintering installations: 10 Mt CO_2 or 0.5%.
- Installations for the production of pig iron or steel (primary or secondary fusion) including continuous casting, with a capacity exceeding 2.5 tonnes per hour: 130 Mt CO_2 or 7%.

Mineral industry

- Installations for the production of cement clinker in rotary kilns with a production capacity exceeding 500 tonnes per day or lime in rotary kilns with a production capacity exceeding 50 tonnes per day or in other furnaces with a production capacity exceeding 50 tonnes per day: 170 Mt CO_2 or 9%.
- Installations for the manufacture of glass including glass fibre with a melting capacity exceeding 20 tonnes per day: 20 Mt CO_2 or 1%.
- Installations for the manufacture of ceramic products by firing, in particular roofing tiles, bricks, refractory bricks, tiles, stoneware or porcelain, with a production capacity

exceeding 75 tonnes per day, and/or with a kiln capacity exceeding $4\,m^3$ and with a setting density per kiln exceeding $300\,kg/m^3$: 10 Mt CO_2 or 0.5%.

Other activities

- Industrial plants for the production of (a) pulp from timber or other fibrous materials and (b) paper and board with a production capacity exceeding 20 tonnes per day: 30 Mt CO_2 or 1.5%.
- Other activity opted-in pursuant to Article 24 of Directive 2003/87/EC (e.g. installations with capacities below the stated limits above): 30 Mt CO_2 or 1.5%.

Unfortunately, the categories are not used in a consistent way for all countries.[9] The main category is combustion with more than 70% of total emissions in the EU ETS. Most installations under this category are part of the public heat and electricity sector, which is responsible for approximately 60% of total emissions. Further relevant sectors are cement, steel, and refineries.

1.5.3 Flexible Mechanisms

Under the Kyoto Protocol, countries may meet their emission targets through a combination of domestic activities and the use of flexible mechanisms. Besides allowing countries to meet their targets in a cost-effective way, flexible mechanisms aim to assist developing countries in achieving sustainable development. The Kyoto Protocol includes three flexible mechanisms:

- Joint Implementation (JI).
- Clean Development Mechanism (CDM).
- International Emissions Trading (IET).

JI and CDM are project-based mechanisms. They involve developing and implementing measures that reduce greenhouse gas emissions in another country to generate emission credits. JI projects are carried out in industrialised countries with existing emission targets (Annex B countries under the Kyoto Protocol). CDM projects are carried out in developing countries without targets. JI projects generate Emission Reduction Units (ERUs) and CDM projects generate Certified Emission Reductions (CERs). Not only CO_2, but all greenhouse gases under the Kyoto Protocol are considered for JI and CDM projects. The unit of ERUs and CERs is t CO_2 equivalents.

JI projects have to be approved by the country in which they are implemented. One criterion is additionality, i.e. the project would not have been implemented without the incentives created by JI. Therefore, measures covered by a company emissions trading scheme like the EU ETS are not eligible as JI projects. The transfer of ERUs generated by JI projects will not begin until 2008.

[9] For instance, power plants in France are listed under other activity opted-in while for most other countries they are listed under combustion.

Under the CDM, investors from Annex I countries receive CERs for the actual amount of greenhouse gas emission reductions achieved. The issuing of CERs is subject to host and investor country agreement, third party assessment, and registration by the UNFCCC Clean Development Mechanism Executive Board (CDM EB). A key requirement for CDM projects is additionality: CERs will only be recognised if the reduction of greenhouse gas emissions is additional to any reduction that would occur without the certified project activity. Additional restrictions for projects apply, e.g. nuclear power projects are excluded. Until February 2007, more than 500 CDM projects were registered by the CDM EB. They are expected to create 700 million CERs until the end of 2012. The majority of these CERs are expected from projects in China (41%), India (14%), and Brazil (14%). Main scopes of the CDM project activities are energy industries (50%), waste handling and disposal (20%), and agriculture (10%).[10]

International Emissions Trading (IET) of Assigned Amount Units (AAUs) allows industrialised countries with emission targets (Annex B countries) to exchange emission allowances to meet their national Kyoto targets for the commitment period 2008–2012. Unlike CDM and JI, IET is not project based. Emissions in some countries, especially in Russia and Ukraine, are significantly below their Kyoto targets (see Table 1.5) and more than sufficient AAUs will be available. The question is whether this “hot air” is politically acceptable for meeting Kyoto targets or not.

Besides AAUs, Annex B countries can also use CERs and ERUs for meeting their Kyoto targets. This is what, for instance, the Netherlands is aiming to do through a state purchasing programme. A number of other countries including Japan, Canada, Sweden, Italy, and Spain are also likely to enter the CER market as buyers.

The Linking Directive (Directive 2004/101/EC), adopted by the EU Parliament in 2004, allows emission reduction units generated by project-based flexible mechanisms (JI and CDM) to be utilised for compliance by companies under the EU ETS. The rationale behind this linkage is to create additional potential for cost-efficient measures and to reduce the overall costs for emission compliance for the participating companies in the EU ETS. The Kyoto Protocol states that a significant portion of reductions should be achieved by domestic actions. Therefore, flexible mechanisms are considered supplementary to domestic measures and most National Allocation Plans (NAPs) have implemented limits for the use of JI and CDM. These limits are applied for each installation separately and not on a nationwide level. The Linking Directive allows the use of all ERUs or CERs that comply with the requirements established under the UNFCCC, with a few exceptions. Credits from forestry projects (sinks) are excluded for the first period but might be allowed for the second period after a revision by the European Commission. Hydro power projects greater than 20 MW are required to be in line with criteria from the World Commission on Dams.

ERUs can only be used in the second trading period of the EU ETS. CERs can be used in all periods and unlike EU Allowances (EUAs), they can be banked from the first to the second period. Therefore, the CERs issued during the first period have a higher value than EUAs of the first period in case of a positive price difference between EUAs of the second and of the first period. In the long run, CER and EUA prices can be expected to converge.

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[10] The UNFCCC Secretariat publishes detailed CDM statistics on the internet under http://cdm.unfccc.int/statistics.

1.5.4 Products and Market Places

Main products on the market are EU Allowances (EUAs) for the first trading period 2005–2007 and for the second trading period 2008–2012. Common are spot, forward, and futures trading of EUAs. In the case of spot trading, the EUAs are transferred from the seller's account at a national registry to the buyer's account directly after the contract is concluded. Forward and futures trades generally have the December of a specified year as settlement date. Physical settlement by transferring EUAs is common, but futures with financial settlement can be found as well. Standardised option contracts for EUAs also exist.

EUA spot and forward contracts as well as options are traded bilaterally (OTC or via brokers). Spot and futures trading is possible at several exchanges. Options are traded at exchanges as well, but the liquidity is very low. Main exchanges are:

- European Climate Exchange (ECX) in Amsterdam.
- European Energy Exchange (EEX) in Leipzig.
- Energy Exchange Austria (EXAA) in Vienna.
- Nord Pool in Oslo.
- PowerNext in Paris.

Figure 1.34 shows the development of CO_2 emission allowance prices since 2005. The development is characterised by high volatility. While futures for the first period (settlement in December 07) and for the second period (settlement in December 08) were priced more or less identically in the beginning, their prices became decoupled. The strong decline in prices for the 2007 futures can be explained by the expected excess of EUAs allocated by the NAPs for the first period.

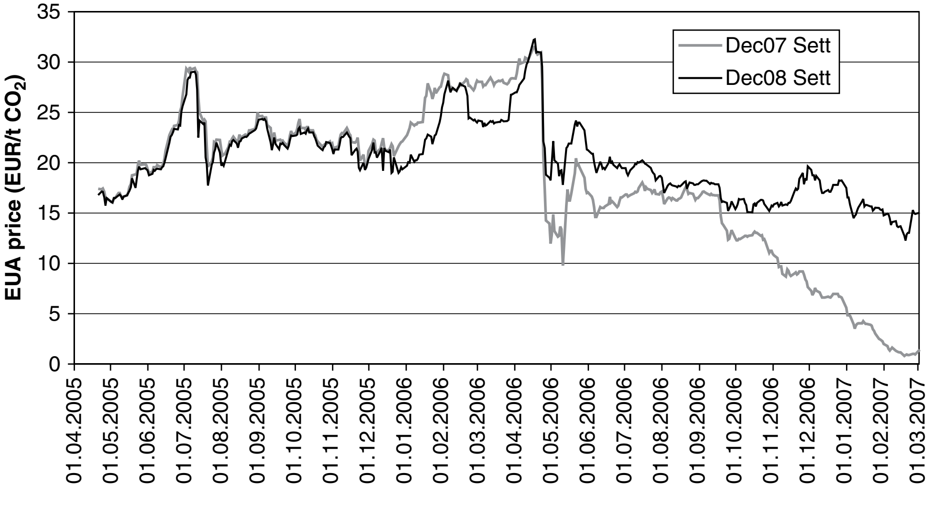

Figure 1.34 CO_2 emissions futures prices. Source: ECX

Fundamentally, the high volatility of CO_2 prices can be explained by the price-inelastic supply of EUAs in the NAPs and by the low demand elasticity in the short term. Most of the short-term demand elasticity exists in the electricity sector where switching from coal fired generation to gas fired generation (fuel switching) is possible. Many other measures for emission reduction require investments with lead times too long for being effective within the first trading period. Further, the demand is uncertain and depends on exogenous influences like wind and hydrological conditions that impact the demand for electricity generation from fossil fuels. On the supply side, CERs have to be considered. As they can be banked from the first to the second period, they will not be available for the first period at prices below the futures prices of the second period EUAs. Figure 1.35 illustrates the fundamental supply and demand situation during the first period. Owing to the very small elasticity of the demand and the inherent demand uncertainty, fundamental prices are very uncertain and may decrease to zero. Assuming sufficient additional supply in the form of CERs, maximum prices will be equal to futures prices for second period EUAs if interest rates are neglected. But as futures prices for second period EUAs are also not stable, a clear upper limit does not exist.

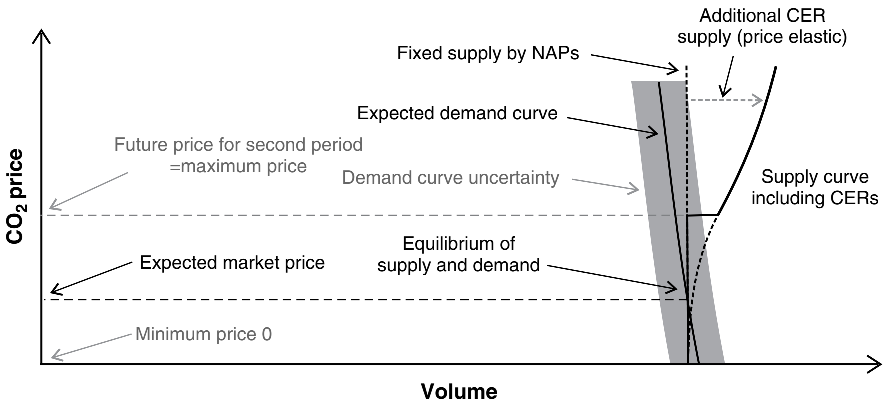

Figure 1.35 Fundamental supply and demand in the European CO_2 market

One additional effect is the allocation in the NAPs. It resulted in most countries in an undersupply in the electricity sector and in an oversupply in all other sectors. Electricity companies were the main actors in the first years. They intended to cover their short position (allocation below expected demand), but only few other actors with a long position (allocation above expected demand) were willing to sell their long position. Further, no consistent and verified historical emission figures for participating installations were available for years before 2005. Based on estimated historical emission figures, a significant shortage in the EU ETS was expected in a business as usual scenario. This led to high certificate prices until April 2006 with peak prices above 30 EUR/t CO_2. At the end of April 2006, certified emission figures for 2005 were published for several countries. They were significantly lower than expected. This led to a price collapse of more than 50% within one week.

CERs and ERUs are traded bilaterally. Unlike EUAs, they are traded internationally and demand is dominated by Annex B countries who buy CERs for achieving their Kyoto targets.

CERs are often bought in the form of bilateral emission reduction purchase agreements (ERPAs). Risks can be distributed differently between buyer and seller. In most cases, the seller commits to delivering all CERs generated from a specific project to the buyer, but the amount of CERs is non-firm. The buyer commits to buying all CERs delivered by the seller for a fixed price.

1.5.5 Emissions Trading in North America

As part of the Acid Rain Program, emissions trading was introduced in the United States in the 1990s for SO_2 emissions from fossil fuel power plants. The so-called "cap-and-trade" method constrains overall emissions and allows certificate trading between participating generation units. In phase I from 1995 to 1999, almost 500 generation units participated. In phase II, which started in the year 2000, the number of participating units exceeds 2000. The Acid Rain Program is regarded as a success, as SO_2 emissions were reduced faster than anticipated.[11]

Regarding CO_2 emissions, the cap-and-trade approach has not been implemented as a mandatory scheme so far. The only greenhouse gas emissions trading scheme operational in the year 2006 in the United Stated is the Chicago Climate Exchange (CCX), a voluntary programme that allows municipal, corporate and other partners to accept a common reduction target for CO_2 and other greenhouse gas emissions under the Kyoto Protocol. It allows full banking flexibility and the use of flexible mechanisms, e.g. in the forestry and agriculture sectors. In 2006, the CCX had approximately 60 members with emission targets.

Mandatory cap-and-trade programmes for CO_2 emissions are considered at state level in the United States. The Regional Greenhouse Gas Initiative (RGGI) was proposed by the Governor of New York in 2003. Targets were defined for the period 2009 to 2015 so far by eight participating states. The establishment of a mandatory trading scheme is also considered in California and Oregon. In Canada, trading schemes might be introduced as well.

Even if these trading schemes will not be linked directly with each other and with the EU ETS, an indirect linkage will exist through flexible mechanisms. Under certain conditions, CERs generated by CDM projects will be accepted in more than one scheme. Therefore, convergence of CO_2 prices in all trading schemes can be expected, at least in the long run.

[11] Detailed information on the Acid Rain Program can be found on the US EPA's Acid Rain Program homepage: http://www.epa.gov/airmarkets/progsregs/arp/.