The Impact of Global Coal Supply on Worldwide Electricity Prices

Overview and comparison between Europe, the United States, Australia, Japan, China and South Africa

Report by the IEA Coal Industry Advisory Board

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For more information about the IEA Coal Industry Advisory Board, please refer to www.iea.org/ciab, or contact Carlos Fernández Alvarez at the IEA (carlos.fernandez@iea.org) or Brian Heath, CIAB Executive Co-ordinator (mail@ciab.org.uk).

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Executive summary

Hard coal[1] is the most important primary energy source in power generation, with 36% of globally generated power relying on this fuel. Its significance varies by world region. In countries with large resource endowments such as China or South Africa, the share of hard coal power generation is more than 80%. In rather import-dependent regions such as Europe or Japan, the share is lower, but with 15% and 25%, respectively, hard coal plays a significant role in power generation as well. Irrespective of hard coal's share of power generation in a region, the influence of coal prices on electricity prices is nearly always considerable.

The report at hand therefore provides an analysis of the impacts of global hard coal supply on worldwide electricity prices. It conducts market studies of six power markets, namely Europe, the United States, Australia, Japan, China and South Africa. Each of these regions is evaluated concerning its respective power market structure, market design, coal supply and the interrelation of coal and electricity prices.

Key messages of this report:

- Hard coal is the dominant fuel in global power generation because full generation costs are well below those of oil, gas or renewables. In regions where power prices are based on full costs due to regulation, low full costs of coal plants directly imply low electricity prices. When power prices are based on short-run marginal costs (the merit order principle), the fuel costs of the price-setting plant matter. Therefore, inexpensive coal serves to decrease the price of electricity, when the price-setting plant is a coal-fired one.
- In Europe and Australia, coal prices have an increasing impact on electricity prices. In those countries, as well as in many US states, power price formation is based on the merit order principle. Expanding renewable energy generation and sluggish or constant power demand increase the frequency of hard coal plants being the price-setting power unit. The more often these plants set the price, the higher the coal price's impact is on the electricity price, irrespective of the coal's share in total power generation.
- In Japan (with the exception of the relatively small deregulated market) or South Africa, where power systems are predominantly monopolistic, coal prices have some impact on power prices as well. Electricity prices are state regulated, based on full-costs. Rising coal prices increase fuel costs and thus also full-costs and power prices. However, other cost components such as capital or operating costs influence electricity prices as well.
- The share of hard coal in power generation is in part driven by the resource endowment of a region. As such, the United States, Australia, China and South Africa exhibit rather high shares of hard coal power generation, being self-suppliers of lower-cost domestic coal. But hard coal also plays a major role in power generation in Japan or Europe, although both are highly dependent on hard coal imports, since coal prices are well below prices of alternative energy sources.
- Given future expansion of renewables, coal power generation in certain regions might decline. However, the coal price impact on power prices can nonetheless increase, as coal plants are likely to increasingly become the price-setting power units. Therefore, future security of coal supply is necessary to keep wholesale electricity prices stable.

[1] Hard coal is defined as coal of gross calorific value not less than 5 700 kcal/kg on an ash-free but moist basis and with a mean random reflectance of vitrinite of at least 0.6. Hard coal comprises anthracite and bituminous coal, *i.e.* coking coal and other bituminous coal.

Europe

- The European Union had a total power generation of 3 260 TWh in 2012, of which hard coal contributed a share of 15%.
- In the light of liberalised European power markets, liquid wholesale exchanges such as the EPEX spot have emerged with price formation following the merit order principle. Nonetheless, European countries still have considerable differences concerning market structure and supply mix.
- In 2012, hard coal-fired power plants were price-setting in Germany in nearly 80% of the hours. This share has increased from 50% within the last years due to the strong expansion of renewables.
- Given the increasing degree of market integration in the European Union (EU) and nearly bottleneck-free power exchange in northwest Europe, hard coal thus has a dominant price impact on the neighbouring western markets as well.
- The impact of the coal price on the whole power price varies in Europe with respect to the share of coal costs at total variable costs, the frequency of coal plants being price-setting, the supply mix and the interconnections to other countries. High coal price impacts can be identified for the Eastern European markets or the United Kingdom.
- Only a minor part of retail power prices is explained by the wholesale price. Retail prices also include taxes, network fees or charges for subsidies to renewable energy.
- The European Union imports more than 60% of its thermal coal demand from the world market at prices historically significantly below those for natural gas or crude oil.

United States

- In the United States, 42% of electricity was produced by coal over the five-year period 2009-2013.
- The US electricity market is separated into three main power grids and different regional wholesale markets. Regulatory models vary by state between full regulation of vertically-integrated utilities where prices are regulated, and regulation of the distribution only, where markets set the power price.
- States with higher shares of coal-fired generation exhibit lower power prices.
- Historically, coal and electricity prices have been related to each other.
- Coal prices exhibit less volatility than natural gas prices, thus fostering power price stability.
- The United States is self-sufficient with respect to hard coal consumption.

Australia

- Hard coal accounts for 47% of Australian electricity supply. However, this share is likely to decrease because Australian energy policy targets 41 TWh coming from renewables by 2020.
- The National Electricity Market is the dominating market region in Australia and the wholesale price, determined by the merit order principle, tends towards short-term marginal costs when there is excess generating capacity, and otherwise to average costs.
- Due to a downturn in power demand and increasing renewables generation, excess capacity has increased and higher-cost hard coal plants dominate price-setting in peak

periods instead of still more expensive gas or hydro plants as before. In off-peak situations lignite or lower-cost hard coal plants are price-setting.

- With the exception of some hard coal plants supplied by export-oriented mines, coal power plants are mainly supplied by captive mines or domestic mines with limited export options, which makes coal prices independent of higher coal export prices.
- Therefore, the Australian electricity wholesale price has remained rather flat and has evolved separately from export hard coal prices.
- However, retail prices have increased sharply since 2006 due to higher network costs and costs of carbon and renewables integration, but prices are well below other comparable countries because of the high share of generation from domestic hard coal.

Japan

- Before and after Fukushima, generation from hard coal has made up 25% of Japanese electricity supply.
- The Japanese electricity market is divided into ten regional state-regulated monopolies, with each monopoly integrating generation, transmission and distribution. The retail sector is becoming rather deregulated, but only 2% of supplies have been sold through the deregulated market so far.
- In the regulated sector, electricity prices are determined by full-cost pricing, whereas wholesale prices in the smaller deregulated market are determined at the Japanese Electric Power Exchange (JEPX) using the merit order principle.
- Coal prices do in part drive regulated electricity prices, since electricity prices are based on full costs of generation and on price adjustments for changing fuel costs.
- Deregulated power prices are rather uninfluenced by coal prices, since gas-fired power plants mainly set the wholesale market clearing price.
- Japan is fully dependent on hard coal imports. Hard coal is mainly purchased on the basis of long-term contracts.

China

- More than 80% of total Chinese power generation comes from coal power plants, which had a total capacity of 834 GW in 2013.
- Besides five big national independent power producers, there are numerous smaller regional generating utilities and local state-owned generators.
- Retail electricity tariffs are strictly regulated by the government, which tries to keep tariffs low in order to preserve public acceptance and to prevent inflation.
- Power generators sell power to the grid operator at regulated on-grid tariffs, which vary by region and are adapted to coal prices.
- Plants purchase coal at widely liberalised prices, which are influenced by (international) supply and demand developments.
- In times of high coal prices, the power sector cannot pass the costs on to the end-user and thus either faces losses or reduces generation, which in turn can lead to power supply disruptions.

South Africa

- 95% of South African power demand is supplied by Eskom, a fully state-owned and vertical integrated utility. Coal-fired plants comprise 85% of Eskom's generating capacity. However, the country is trying to increase the share of independent power producers.
- The National Energy Regulator of South Africa (Nersa) sets a revenue cap based on Eskom's full generation costs, which is then translated into a variety of tariffs differentiated by customer groups.

Table 1 • Overview of market characteristics in different regions

	Europe	United States	Australia	Japan	China	South Africa
Hard coal in power generation	15% out of 3 260 TWh of total power generation	42% (five-year average)	47%	25%	83%	85% of Eskom's generating capacity, 92% of 232.8 TWh produced
Electricity market structure	Liberalised competitive power markets, advancing market integration, variety of national energy policies (*e.g.* renewables subsidies)	Three main power grids and different regional wholesale markets, regulatory models vary by state (full regulation vs. distribution regulation)	NEM dominates market region, competitive energy only market	Ten regional state-regulated monopolies, vertically integrated over generation, transmission, distribution and partly retail, retail at minor share deregulated	Five big independent power producers, smaller regional generating utilities and local state-owned generators, two grid operators	Eskom is state-owned vertically integrated monopoly company
Price formation	Merit-order principle at wholesale markets	In regulated states, price is based on full-costs and fuel cost adjust-ment. Restruct-ured states follow merit-order pricing.	Merit-order principle at NEM wholesale market, price ceiling	Regulated price based on full-costs and fuel cost adjustment system, deregulated retail: merit-order price at JEPX	On-grid electricity tariff regulated by government with fuel adjustment based on coal prices	Revenue cap for Eskom based on fuel, operating and capital costs, revenue cap broken down to tariffs for consumer groups
Hard coal supply	60% of hard coal demand is imported to EU	Fully self-supplied	Fully self-supplied, mostly captive mines but some coal supplies have dependence on coal export prices	Fully dependent on hard coal imports, purchased mainly over long-term contracts	In 2012 China imported 300 million tons (Mt) and produced more than 3500 Mt domestically	South Africa is fully self-supplied, mostly captive mines, domestic coal price is one-third of coal export price
Electricity price impact on hard coal	High impact, since mid-merit coal plants set the price in 80% of the hours due to renew-ables expan-sion and high cost different-ces from gas plants.	Coal prices have been relatively sta-ble for decades and directly correlated with lower rates. Many restruct-ured states have signify-cant gas capa-city, gas gener-ation and typic-ally higher rates.	High impact, since mainly hard coal plant are price setting due to sluggish demand and increasing share of renewables	Regulated retail: medium impact since coal costs influence full-costs and thus the power price; unregulated retail: rather no significance as gas plants are usually price setting	Low impact since govern-ment tries to keep retail prices down; thus high coal prices imply losses for power or grid utilities	Medium im-pact since coal costs are part of total power generation costs, com-prising capital costs and other operational costs

- Eskom therefore is incentivised to minimise costs by dispatching according to variable costs. However, the current low supply reserve margin makes all plants run at full capacity.
- Coal power plants are domestically supplied by either dedicated mines or through short- and medium-term contracts from export-oriented mines. Historically, domestic coal prices have been roughly one-third of international prices because of lower coal qualities, lower transport costs and constrained export infrastructure limiting international price impacts.
- Primary energy costs for coal account for a significant part of power generation costs. However, they are not perfectly correlated with electricity prices, as full power generation costs comprise other cost components as well, such as capital costs and other operational costs.

Introduction

Coal is the world's primary energy source for power generation, accounting for some 36 percent of global electricity generation. Its significance varies greatly among countries and world regions. A fundamental parameter is the resource endowment of each specific region. Usually, hard coal is of particularly great importance if there are domestic deposits that are economically mineable. This is the case in the United States, Australia, China and South Africa. In countries or regions that are entirely or predominantly supplied with hard coal from the world market, such as Japan and the European Union, hard coal makes a significant contribution towards ensuring security of supply.

Coal plays a special role in the price formation process on the electricity markets. In this respect the costs of hard coal often have a significantly greater influence on electricity prices than the percentage share of hard coal in power generation. Therefore, hard coal price swings disproportionately affect wholesale electricity prices in the areas which were studied. The study at hand highlights the significance of hard coal for all continents, using the examples of the above markets.

Structure of the electricity markets

The utility structure in the regions under examination differs significantly, ranging from a single, dominant utility (France and South Africa) all the way to a competitive market situation with a whole host of market actors (the United States and Germany).

Electricity grids and their cross-border connections are structured very differently, resulting most notably from the countries' specific geographic features. Japan being an island country has a purely internal grid without any external connections. Owing to their vast size, the United States and Australia even have several grid regions that are hardly interlinked. In northwest Europe and South Africa, the electricity grid has been fully integrated for several years now. Some transmission bottlenecks still existing at the national borders are continuously reduced.

It is assumed that the electricity demand in all countries under examination in this paper will remain constant or will slightly increase in the future. This is especially true of the OECD countries for which only a moderate economic growth has been forecasted. The situation is different in South America, where demand is growing and new coal-fired capacity is under construction. Electricity demand is expected to grow in China, and even though the Chinese government is trying to diversify primary energy sources, coal will remain the backbone of Chinese power generation.

Market design

In terms of market design, there are again significant regional variations, ranging from nearly full regulation to price formation in the market. In Japan and South Africa, electricity prices are set by the regulatory authorities according to the full-cost principle. In China, the regulator sets retail prices and tries to keep prices low. Following the European path, the liberalised market, which is currently still very small, is to be expanded. In Europe, electricity prices are largely determined according to the market principle. However, there are also certain exceptions, such as renewable energy, which is promoted with special subsidies (especially in Germany).

In Australia, the market principle determines wholesale electricity prices, although retail pricing is largely regulated, and the United States has the full range of different regimes evident in individual states. One feature all regions have in common is that the electricity grids, being natural monopolies, are fully regulated.

There are wholesale exchanges in many regions; their significance depends on the specific degree of regulation. In Europe, large quantities of electricity are traded at various exchanges, with the prices being identical in the different market places most of the time. By contrast, in Japan only 1% of electricity is traded at the exchange.

As a matter of principle, electricity price formation in Europe follows the merit-order principle – with the exception of renewable-energy remuneration. But also in Japan, the merit order is used as guidance for pricing. In principle, the monopoly Eskom in South Africa also applies the merit order approach in order to minimise costs; however, all power plants are owned by the same operator. In China, dispatch is centrally planned, which leads to certain inefficiencies.

CO_2 emissions are priced differently. In South Africa, at present, the electricity price includes a relatively small environmental protection markup; the introduction of a CO_2 tax is planned for the future. Japan and Australia already have a CO_2 tax. The European cross-border CO_2 certificate system is currently the first of its kind. In the United States, there are only geographically limited systems to date, however, extension of is under consideration.

Despite all the differences concerning market design, coal-fired power generation plays a huge role in all countries. This becomes particularly clear when looking at the power plants' utilisation levels. In all regions under consideration, the existing coal-fired power plants are needed in some 50% to 95% of all hours to cover electricity demand. When electricity consumption rises, *e.g.* in the morning hours of a day, additional hard coal-fired power plants are frequently operated to cover the demand. In deregulated electricity markets, the plants' generation costs incurred in this way must be reimbursed via the electricity price. If the generation costs of coal-fired power plants go up, the market price of electricity will directly rise in these hours. In an analogous manner, the same applies if the coal plants' generation costs fall. In this way, the liberalisation of the global power markets helps to directly implement the price effect of hard coal described above.

Fuel supply

The quantity of hard coal imported and exported primarily depends on the domestic deposits existing in the specific country. As coal is an important energy carrier in all regions, a wide variety of forms is possible. in Japan, for instance, the entire demand for coal is covered by imports, while particularly Australia and South Africa mine considerably more coal than required to meet domestic demand, which makes them not only self-suppliers but also exporters of hard coal. China is the world's biggest producer, consumer and importer of coal.

Developments in coal and electricity prices

In the United States and Europe, most notably in Germany, there is a strong correlation between developments in coal and electricity prices. While this has been the case in the United States for decades now, in Europe, the dependence of electricity price levels on hard coal prices has increased more recently as a result of the strong expansion of expensive renewables. Their feed-in priority has caused the merit order to change, so that coal-fired power plants are setting the price to a greater extent. In Australia, sluggish demand makes coal plants become more and more price setting as well. In Japan the merit order has also changed, albeit with other implications. Due to the decommissioning of nuclear power stations in the aftermath of the Fukushima disaster, the marginal plants are nowadays, above all, natural gas-fired stations. The price of coal is only important in so far as it must be taken into account by the regulators as being part of the full costs when setting prices. In South Africa the situation is similar. In China, coal-fired power plants have to purchase coal at market prices, whereas they sell electricity to the grid operator at regulated tariffs which include some fuel cost pass-through mechanism. Since end-user electricity prices are regulated as well and kept low by the government, generators or grid operators face losses from rising coal prices.

Global coal prices have slightly risen in recent years, both in real and nominal terms. Before the economic crisis started, the price in Europe rose sharply, with a corresponding impact on power prices; conversely, lower coal prices in 2012 had a bearish effect on wholesale power prices.

Electricity prices vary considerably in the different world regions. The low price of coal (especially compared with other energy carriers) has had a dampening effect on the electricity price in the United States and South Africa. In this respect, US states with a higher coal share in electricity generation also have lower electricity costs. A change in the philosophy of depreciation values and the need to finance new capacity has caused the electricity price in South Africa to increase significantly in the last few years. In Europe, higher electricity prices are most notably resulting from sharp increases in burdens imposed by the Administration. Although deregulation has led to a fall in prices in Japan, this was partly offset by higher costs following Fukushima. In Australia, the price for households went up owing to the grid expansion.

Europe

Structure of the electricity market

The creation of a cross-border market for electricity in the European Union has given rise since 1998 to one of the world's largest interconnected power-supply regions and one which has been subject to a common price formation process.

Power generation in the EU-27 totalled 3 295 terawatt hours (TWh) (gross) in 2012. The structure has a breakdown by energy carrier as follows:

Table 2 • EU-27 power generation by energy carrier in 2012

Energy carrier	Percentage
Nuclear	26.8%
Hard coal	16.5%
Lignite	10.3%
Natural gas	17.6%
Oil	2.2%
Other non-renewable sources	5.9%
Hydropower	11.1%
Other renewables	9.6%

Source: Eurostat, 2014.

Both as regards the energy mix and the market structure, there are still considerable differences among the EU states.

Greece's and the Czech Republic's power generation, for instance, rely heavily on domestic lignite. In Poland, hard coal is the most important source of electricity generation, but supplemented by the country's lignite as another significant pillar. In the Netherlands, natural gas is the heavyweight, as is the case in Italy, where natural gas accounts for 54% of electricity generation. In Austria, hydropower is abundantly available thanks to the country's natural conditions. This is also true of Sweden, albeit with some qualifications. There, use is also made of nuclear energy to generate power. In France, more than two-thirds of power generation is based on nuclear energy. By contrast, countries such as Italy and Austria, on political grounds, do not use nuclear energy. In the case of Italy, a 2011 referendum has re-confirmed the step away from nuclear of 1987. Germany, in the aftermath of the 2011 reactor accident in Fukushima, has decided to phase out nuclear energy completely by the end of 2022. In the United Kingdom the generation mix is strongly dependent on the competitive position between coal and gas. In 2012 around 40% of electricity was coal-based – an increase of over 30% from 2011 – as a result of continuing high gas prices and relatively low generation costs for coal-fired plants. Spain, with its limited domestic resources except for coal, has a diverse mix of nuclear, coal, combined-cycle gas turbines (CCGTs) and renewables - wind and solar as well as hydro. Given the current gas and coal prices, coal-firing generation exceeded CCGTs by about 40% in 2012. Notably, the Spanish coal capacity is at less than half of CCGTs' capacity. Notwithstanding, the Spanish government has been prioritising domestic coal by application of an EU directive that entitles member states to do so on grounds of security of supply.

The most important reasons for the considerable variations in the energy mix among the EU member states are differences in their endowment with natural energy resources and their various energy policies.

Although the EU's energy policy – in a spirit of solidarity among the member states – aims at ensuring the central Community goals of a functioning single market, guaranteed security of supply, the promotion of energy efficiency, an expansion of renewable resources and the link-up to the energy grids, member states retain responsibility for the conditions of use of their energy resources, the choices made between different energy sources and the determination of the general energy-supply structure.

Despite common EU energy politics, political interventions at the country level have grown in frequency in recent years, increasing risks for energy investors. Recent examples in Germany include: the introduction of a nuclear tax in 2010, the decision to exit from nuclear power in 2011 and plant closure restrictions in 2012. In the neighbouring countries, Belgium added a nuclear tax in Belgium in 2011, the Netherlands added a coal tax in 2012 and the United Kingdom introduced both a carbon floor price in United Kingdom in 2013, and an emissions performance standard, which prevents the construction of new coal-fired power stations without carbon capture and storage (CCS), whilst allowing the unabated construction of gas plants. Similar measures have been introduced in other EU member countries.

Likewise, the market structure in the European power-generation sector also varies significantly between member states. Examples of states where one single power producer plays a dominating role are France and Greece. By contrast, a low degree of concentration can be noted for countries such as the United Kingdom, Germany and the Netherlands. In Germany, the EU's largest electricity market, for example, the four largest power producers together account for a 45% share in total generation capacity and produce 60% of the power generated. In addition, there are more than 100 independent power plant operators with plants of more than 10 MW – regional and local providers – as well as over one million operators of small PV, wind, water, biomass and biogas plants. In Spain, the five largest generators produce around 70% of all generated power, with many small producers of combined heat and power (CHP), wind, photo-voltaic (PV), etc.

The national electricity grids have been linked by interconnectors for several decades primarily to ensure grid security. With the liberalisation of the energy markets at the end of the 1990s, cross-border trade in electricity was added. Electricity trading initially had to face system-related constraints. In recent years, however, there has been an increasing coupling of the national markets.

A milestone in the integration of the EU's electricity markets was reached in November 2010 with the coupling of the northwest European markets (Germany, France, the Netherlands, Belgium and Luxembourg). Since then, the national electricity spot markets of nine countries have been coupled at a wholesale level. The positive implications this move was expected to have for market results – from optimal utilisation of cross-border capacities – have materialised. In some 60% of the hours, for instance, the same price can now be noted on the wholesale market in France, Germany, Belgium, the Netherlands and Luxembourg. Before the Central Western Europe Market Coupling became effective, this was the case in less than 1% of the hours in a year. The Nordic region is expected to be coupled with Western Europe in the next phase. The EU Commission and the European Agency for the Cooperation of Energy Regulators (ACER) aim at coupling the spot markets as a target model for the entire EU by 2015. However, in the short and medium term there a still limited interconnector capacities preventing a completely barrier-free market region across the EU.

From the year 2005 on, electricity demand has been largely constant in the EU. Once the economic crisis has been overcome, consumption is expected to rise again – although limited to the scale of an annual 1% on average. Depending specifically on the initial cyclical situation and on specific economic perspectives, developments are likely to vary among the member states. In Germany, for example, electricity consumption is expected to be largely stable in future, as it is in the United Kingdom, whereas for other states – Eastern Europe in particular – growth perspectives of over 1% per year are assumed. Growth figures could be significantly higher if other sectors – *i.e.* transport and heat – become more dependent on electricity.

Market design

For the power generation industry, liberalisation of Europe's energy markets has meant that competition has become the determining market principle – apart from renewables which are supported by state subsidies. Unlike the grid business, which is subject to state regulation as a natural monopoly, market prices for conventional power generation are directed by supply and demand only.

Since the opening of national markets in 1998, liquidity in electricity trading has grown continuously all over Europe.

Germany's electricity trading market, with a churn rate of about ten, is the most liquid electricity-trading platform in Europe. (Churn rate refers to the ratio between trading volume and physical consumption.) The reasons are the size of the market and the heterogeneity of the market actors, along with Germany's geographic location as a European hub, and ever greater transparency.

Europe has about 12 power exchanges. The most important trading centres for Central Western Europe are the Leipzig-based European Energy Exchange (EEX) and the French exchange Powernext, based in Paris. German and French futures trade in electricity is bundled in EEX Power Derivates, a majority-owned EEX subsidiary registered in Leipzig. Being Europe's most liquid electricity wholesale market, the German wholesale market serves as crucial reference: the base-load contract for the following year has further extended its role as benchmark contract for electricity in continental Europe.

In addition to a liquid futures market, there is also a liquid spot market for electricity in continental Europe. The French Powernext exchange and the European Energy Exchange in Leipzig have bundled their electricity spot market activities for Germany and France and combined them in a cross-border joint venture called European Power Exchange (EPEX Spot) based in Paris. EPEX Spot operates the short-term power exchange trade in Germany, France, Austria and Switzerland. It thus forms the core of the spot market in the Central Western Europe region.

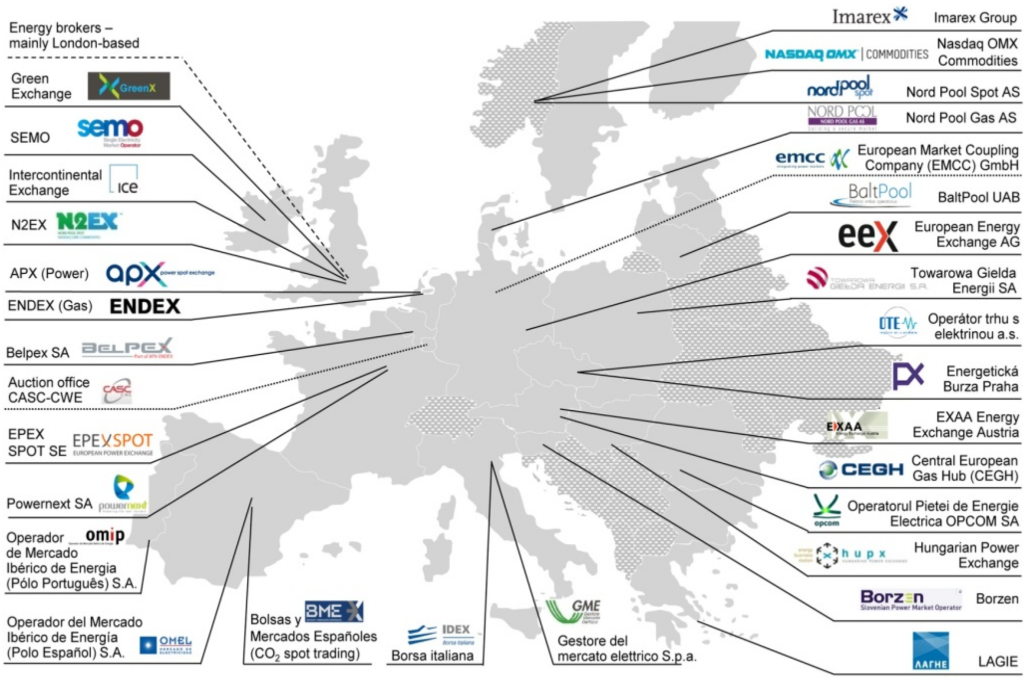
Besides trading via the various European exchanges, the trading activities in the electricity area mainly take place on off-market trading platforms, known as over-the-counter (OTC) platforms.

Since liberalisation, trading volumes in the various EU countries have grown. However, marked differences in trends have emerged, these being due, *inter alia*, to decisions on the necessary regulatory conditions.

Price formation on the wholesale electricity market follows the merit order principle. In Central Western Europe, the generation capacities installed there are in direct competition with one another. Dispatch of power plants depends on the Central Western European merit order and on demand.

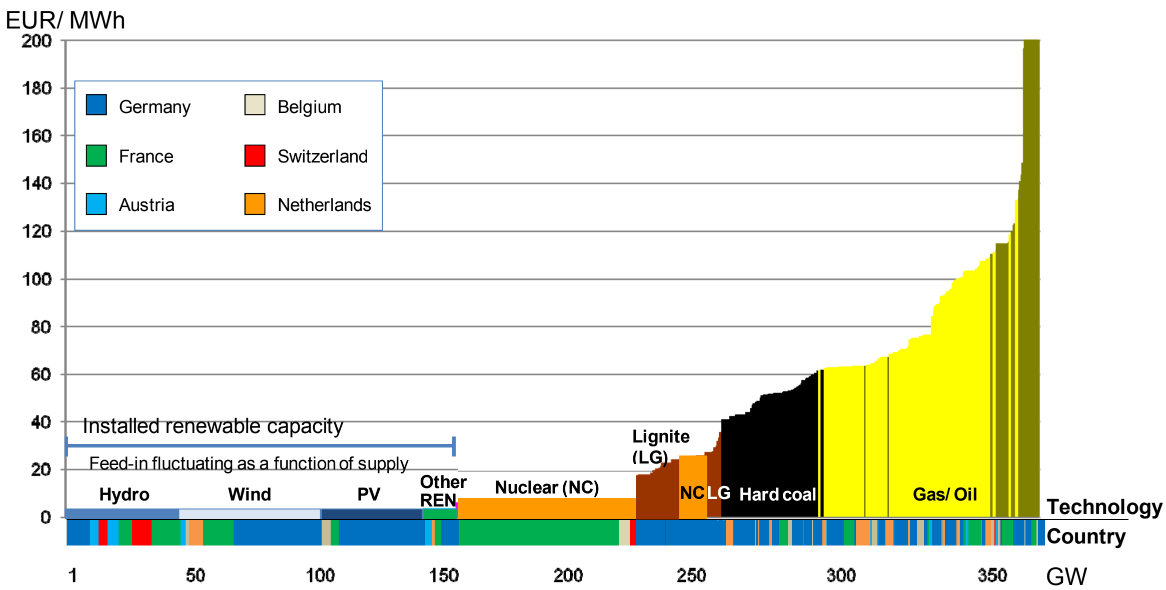
The merit order of the existing power plants is determined by the level of the variable costs of the various plants. Since the variable costs of renewable energy sources – apart from biomass – are virtually zero (wind and sun) or relatively low (water), their supply is at the very left in the merit order. Furthermore, renewables are prioritised in electricity feed-in that is guaranteed by statute. After the renewable energies – at current fuel and CO_2 prices – the still available nuclear power stations and lignite power plants supply electricity according to the most favourable conditions, followed by plants based on hard coal. Gas has the highest variable costs at the moment (Figure 2). Only in exceptional situations are oil-based power plants still dispatched to cover general electricity demand. This holds true for nearly all EU member states.

Figure 1 • Wholesale market places for electricity and energy products in Europe 2013



Source: EEX, 2013.

Figure 2 • Northwestern European merit order that decides the power plant dispatch



Source: RWE analysis, 2013.

Prices form at the point of intersection of the resulting supply curve and the demand curve. This guarantees an efficient dispatch of the power station fleet, since total generation costs are minimised in any load situation. The market clearing price reflects the variable costs of the last power plant just needed to cover the demand concerned (marginal plant). The market price thus formed is paid to all power plant operators which have supplied electricity quantities below this price, irrespective of the level of the variable costs of the power station concerned. Thus, there is only one electricity price at the wholesale level.

The margins between the wholesale price and the variable generation costs of the various power stations are needed to cover the fixed costs for operation and maintenance and to compensate for the cost of capital.

Since 2005, power plants, but also the plants of industry, have been subject to the Emissions Trading cheme (ETS) which is regulated EU-wide. For the plants that are subject to the ETS, the CO_2 emission caps are binding for the period up to 2020. The prescribed reduction after 2012 follows a path that provides for an annual 1.74% reduction in CO_2 emissions until 2020. This will achieve the 21% fall in CO_2 emissions aimed at by 2020, compared with 2005, for the plants that are subject to the ETS.

The economic crisis in Europe in particular together with the heavily subsidized expansion of renewables has significantly dampened the demand for CO_2 emission certificates. Whereas between mid-2005 and mid-2008, CO_2 prices of up to EUR 30/t were achieved in places, quotations have weakened since then. Most recently (16 December 2013), they stood at a mere EUR 5/t CO_2.

The European Union is evaluating options to the ETS. This may be done via a short-term supply adjustment to raise the price of allowances (so-called backloading) and may go as far as a structural reform to the trading system.

The prices for CO_2 certificates are a component of the variable costs of fossil-fired power plants. Depending on the level of the fuel and CO_2 costs, they can change power stations' dispatch merit order. In view of relatively high gas prices in Europe and the low CO_2 prices, the CO_2 ETS is at present not triggering a fuel switch from coal to gas. In fact, gas power plants are at the very right in the merit order.

An analysis for Germany shows the following utilisation of hard coal and gas-fired power plants in 2012. The data per fuel class vary owing to a plant's age and efficiency:

- lignite: approximately 80% to 95%,
- hard coal: approximately 50% to 80%,
- natural gas: up to approximately 20%.

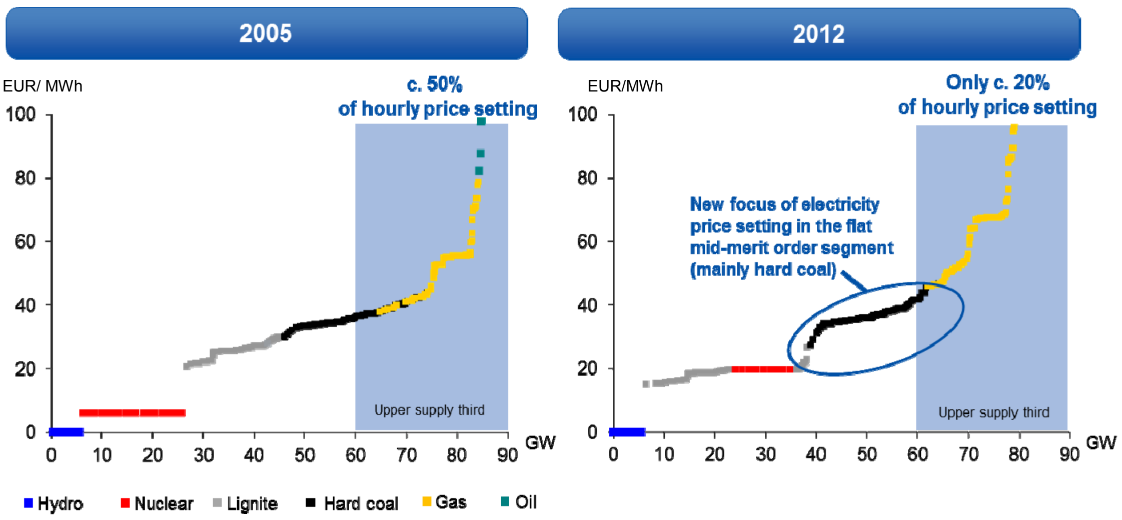
The utilisation of the plants follows directly from their position in the merit order. The higher their variable generation costs, the fewer hours they are demanded by the market. In the United Kingdom, coal plants have operated in mid-merit for several years, with load factors typically around 40%, but coal load factors have increased more recently as a result of higher gas prices. In the future they will be increasingly constrained by Industrial Emissions Directive requirements and by the UK government's carbon floor price (which is essentially a carbon tax).

In the hours in which gas capacities are needed to cover electricity demand, the short-term generation costs of these plants determine the level of the electricity prices in exchange wholesale trade. In 2012, therefore, for about 20% of all traded hours, electricity prices were set by gas-fired power stations. This share has fallen from roughly 50% in recent years. The reason for this is the strong expansion of renewables, which has meant that – where the share of wind and solar is high – the existing gas-fired power plants as well as sections of the hard coal portfolio are no longer needed as temporary substitutes. As a result, the influence on electricity prices exerted by hard coal power stations positioned more to the left in the merit segment has risen. In this way, the electricity prices in the remaining 80% of the hours are almost completely determined by the generation costs of the existing hard coal-fired power plants. The reason is that power consumption – even after deduction of the feed-in tariff from renewables – only in exceptional cases falls so low that the low-cost lignite-fired and nuclear power stations as well are no longer fully needed to cover demand.

Owing to the market-related positions of hard coal in the mid-merit segment, hard coal on the German market is thus very largely price-setting, although hard coal's share in the power-generation quantity in 2012 stood at a mere 19%.

Owing to the cross-border trade in electricity with neighbouring markets, hard coal's dominating price impact on the electricity markets becomes perceptible in the whole of northwest Europe. The frequently bottleneck-free exchange of electricity with Benelux and France leads to a direct passing on of the prices to neighbouring western markets. In the neighbouring northern and eastern markets, the price effect from the hard coal capacities in Denmark, Poland and the Czech Republic is increased even further. In the United Kingdom low coal prices contribute to the switch from gas, but interconnectivity with the rest of Europe is limited.

Figure 3 • Merit order of the German wholesale portfolio, 2012 versus 2005



Note: The costs for nuclear power generation have risen as since 1 January 2011 utilities have been required to pay a tax on fuel elements.

Source: RWE analysis, 2013.

However, although the EU electricity markets are linked via interconnector capacities, the available transfer capacities vary significantly. Some markets are already fully integrated, while others still show regular scarcities when available interconnector capacities are fully exploited. In a simplified description, the current situation of the interconnected transmission grid results in a few different market zones within the EU.

- **Central-West:** the Netherlands, Belgium, France, Luxembourg, Germany, Switzerland*, Austria, Denmark-West
- **East:** Poland, the Czech Republic, Slovakia, Hungary, Slovenia
- **North:** Norway (not an EU member state, but integrated in the liberalised EU electricity market), Sweden, Finland, Denmark-East

- **Baltics:** Lithuania, Latvia, Estonia
- **GB/Ireland:** the United Kingdom, the Republic of Ireland
- **Iberia:** Spain, Portugal
- **Italy**
- **South-East:** Romania, Bulgaria, Greece

Due to the different proportion of coal-fired generation capacities in these markets, the impact of coal prices on electricity prices varies slightly. The following table indicates to what extent increasing costs for hard coal are directly passed through to electricity prices at the national power exchanges.

Table 3 • Proportion of coal price increases passed through to electricity prices

Central-West	East	Baltics	North	GB/Ireland	Iberia	Italy	South-East
60% - 70%	70% – 80%	40% – 50%	40% – 50%	50% – 60%	40% - 50%	30 – 40%	60 – 70%

Source: RWE analysis based on commodity price developments, 2013.

Power plant fuel supply

In the European Union, some 60% of hard coal needs are covered by imports from third countries. In Germany, the import share even reached 80% in 2012. The prices of steam coal in Germany are entirely determined by world market prices. This is also true of the hard coal quantities that will still be mined at a higher cost in Germany until 2018. The difference between extraction costs and import prices – the crucial values in this connection are the quotations cost, insurance and freight (CIF) Rotterdam – is offset by subsidies from the federal budget. In Italy, 100% of its hard coal stems from tertiary country sources; however, with coal accounting for a mere 12% of all energy generation, effects are still limited.

In Germany, power plant operators pay only market prices for hard coal. This is true of both imported and domestic hard coal. Most coal imports are done on a floating basis indexed to financial trading instruments such as the API2/API4. Buyers and sellers can then fix price levels in the traded market either on exchanges or in the over-the-counter market. In the United Kingdom all coal is freely traded with no subsidy, so indigenous producers must compete with imported prices.

The competition between hard coal and gas plays a huge role in power generation. Although the cost of capital for a coal power plant – with comparable output – is higher than for a gas-fired power station, currently the costs of hard coal as input energy in Europe are much lower than natural gas. The technical dispatch ability is similar in both cases.

For electricity price formation on the wholesale market, only the variable costs, *i.e.* mainly fuel and CO_2 costs, are relevant. The variable power-generation costs for hard coal – despite the usually higher efficiency of gas-fired power stations – are much lower at present than for plants on a gas basis. If we assume unchanged fuel price ratios, the CO_2 price would have to rise to over EUR 30/t to trigger a switch in the dispatch order of hard coal and gas power plants.

A CO_2 price at this level would have a considerable impact on wholesale electricity prices. The corresponding rise in electricity prices would jeopardise the competitiveness of the power-consuming industry unless comparable burdens for the electricity price from a CO_2 regime are put in place outside Europe.

The development of hard coal and electricity prices

The chief trading platform for imported coal in Western Europe is the Dutch/Belgian region, with the ports of Amsterdam, Rotterdam and Antwerp (ARA). Price formation in the ARA region is taken as the reference for Western Europe as a whole. Price developments are shown in the following table. Since the start of the millennium, the prices of steam coal have risen by more than 100%. Price volatility, too, has increased significantly. During the 2007/2008 boom, there were extreme price peaks at times. With the start of the financial and economic crisis, price developments have stabilised at a higher level after a decline associated with the business cycle.

The necessary inland transport of the hard coal to the domestic power plants leads to additional logistics costs ranging between EUR 5/t and EUR 15/t for hard coal, depending on the link-up of the locations to waterways or the rail network.

Wholesale electricity prices have evolved partly in parallel with the course taken by hard coal prices, although in places, a divergence can be noted (*e.g.* 2007). An important reason for this was the severe fall in the CO_2 price from over EUR 30/t in mid-2006 to practically nil in the course of 2007. (The massive erosion of the CO_2 prices was due to the fact that emission rights could not be transferred to the second trading period of the ETS, which began on 1 January 2008.) In mid-2008, the CO_2 price again reached a peak of around EUR 30/t. Thereafter, a definite decline was noted – triggered above all by the economic crisis in Europe and by the strong expansion of renewables, which has meant that the more expensive gas-fired power plants became price-setting in ever fewer hours. Whereas only a few years ago, gas-based power stations were price-setting in half of the hours, this is only the case nowadays in about 20% of the hours.

If the hard coal price rises by 10%, *i.e.* in the above example from EUR 90/tce to EUR 99/tce, fuel costs increase by EUR 1.1/MWh_{th}, equivalent to EUR 2.9/MWh_{el}. The effect is a rise in variable costs (with an unchanged CO_2 price) by 8.7%. If the hard coal-fired power station is price-setting in 80% of the hours, the wholesale electricity price (on the above assumptions) may be presumed to go up 7% if the hard coal price increases by 10%. Where CO_2 prices are higher, the effect in relative terms would be lower.

Table 4 • Developments in hard coal prices and wholesale electricity prices

Year	Spot price for steam coal free Western European seaports	Average import price for steam coal free German border	Wholesale electricity price (spot price) EUR/MWh	
	USD/tce	EUR/tce	Base load	Peak load
2000	42	42		
2001	46	53	25	36
2002	37	45	23	32
2003	50	40	29	43
2004	84	55	28	38
2005	71	65	46	56
2006	74	62	51	64
2007	101	68	38	49
2008	175	112	66	79
2009	82	79	39	47
2010	107	85	44	51
2011	143	107	51	57
2012	109	93	43	49
2013	95	79	38	43

Source: VDKi, BAFA, EEX, 2013.

Box 1 • The fundamental correlation between coal and electricity prices

The implications of a rise in hard coal prices for the wholesale electricity price shown by an example:

The assumptions in the example of the following:

-- coal price (6 000 kcal/kg): USD 90/t CIF northwest Europe

-- transport costs to the power plant: USD 10/t

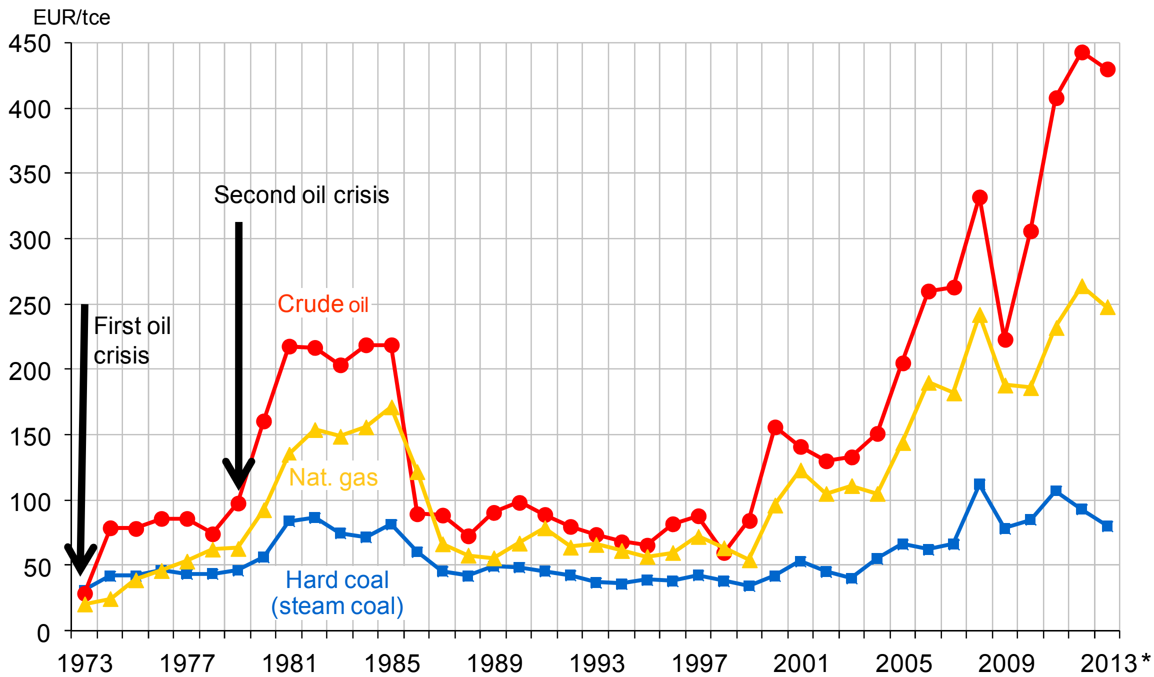
-- exchange rate: USD 1.30/EUR.

From this, we obtain a coal price, free power plant of EUR 90/tce, equivalent to EUR 11/MWh_{th}. With an assumed electric efficiency in the power plant of 38%, fuel costs amount to some EUR 29/MWh_{el}. With a likewise assumed CO_2 price of EUR5/t, the CO_2 costs per MWh of electricity generated amount to EUR 4.50 /MWh_{el} (CO_2 emission factor of 900 kg/MWh_{el} for a hard coal-fired power station having 38% efficiency). In total, the variable costs amount to EUR 33.50/MWh_{el}.

Consumer prices for electricity (Germany as an example) plummeted initially after the liberalisation of the power market in 1998. Liberalisation was associated with a departure from the principle of price formation according to average costs. Since then, only the transmission and distribution functions – as natural monopoly – have still been subject to state regulation.

The prices of hard coal and natural gas, free German border, fell to EUR 34 and 53/tce, respectively, in 1999. In the sequel, hard coal and gas prices rose again, and this development even accelerated from mid-2003 on. In 2008, hard coal and gas prices, at EUR 112 and 237/t respectively, reached a level that was equivalent to a quadrupling of the comparable value in the year 1999 (Figure 4). In the wake of the 2009 economic crisis, prices fell, although this was followed by renewed stabilisation. The variable costs that determine the price of electricity were additionally impacted after 2005 by the quotations for CO_2 emission certificates.

Figure 4 • Developments in selected primary energy prices free German border (nominal)

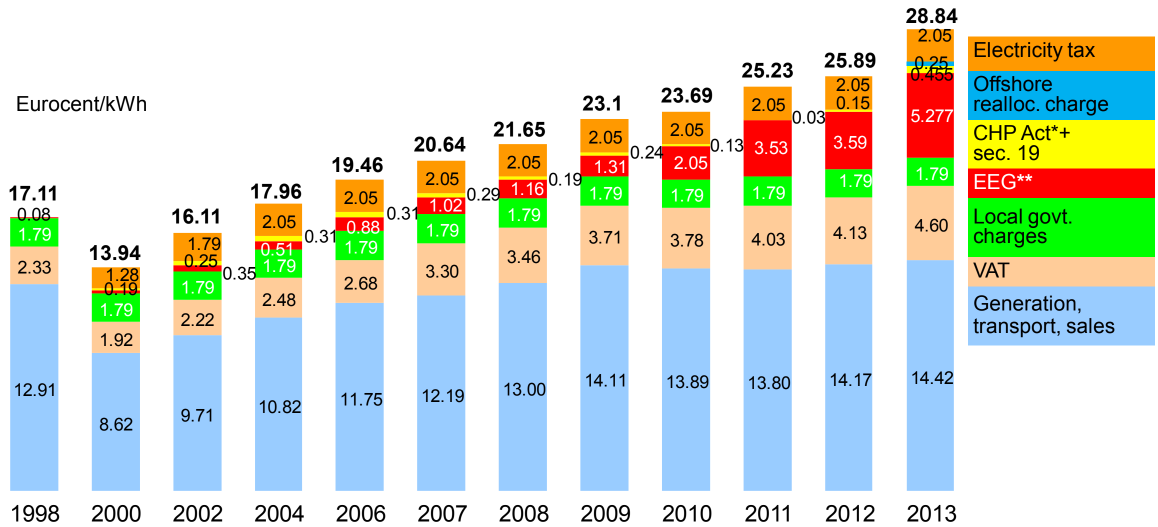


* January to September 2013

Source: Federal Office of Economics and Export Control – BAFA (2013): www.bafa.de.

Developments in consumer electricity prices (calculated without taxes and burdens imposed by government) reflect the course taken by variable costs. Consumer electricity prices, including taxes and levies, have doubled in Germany since 2000, due to the following: (1) the reallocation charge in favour of renewable energy, which had increased to EUR 52.88/MWh by 2013; (2) the electricity tax, which was introduced in 1999 and then successively raised to EUR 20.50/MWh; and (3) the newly launched reallocation charges on grid access fees (Figure 5). Both industry and households can easily switch electricity providers.

Figure 5 • German electricity price for private households



* Total burden from CHP Act fell as from 2002; as from 2012, shown including section 19 reallocation charge, ans as from 2013 including offshore reallocation charge for liability (owing to relief for industry, growing burden for households)

**Renewable Energy Sources Act; from 2010, application of Ordinance on Nationwide Equalization Scheme (AusgleichMechV)

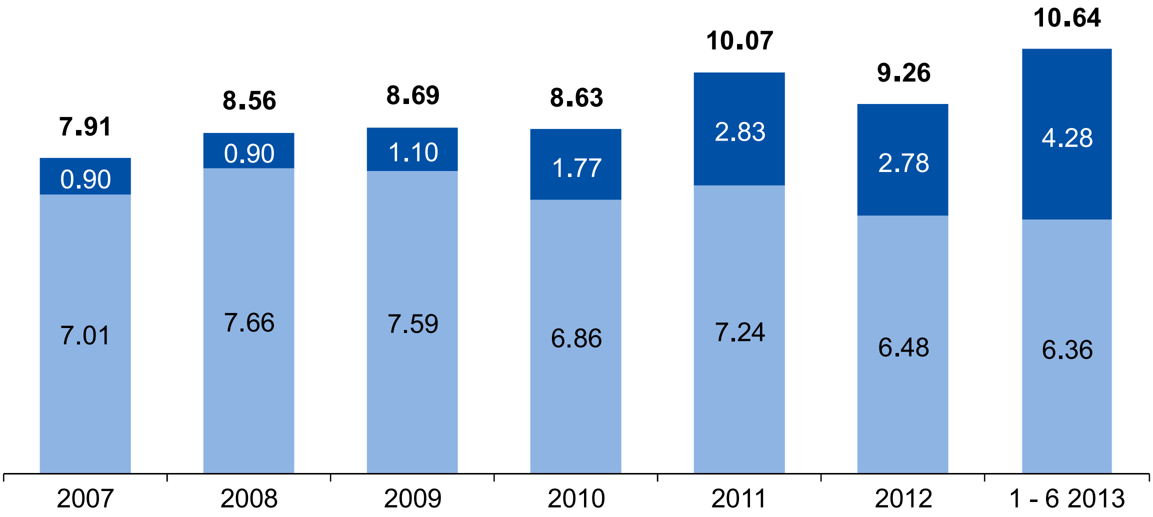
Source: BDEW, 2013.

The energy-consuming industry has only been a little burdened by these state-imposed levies and reallocation charges, so that it has been possible to keep electricity prices for industries with relatively high power consumption fairly stable (Figure 6).

Despite Spain's electricity deficit (see Box 2), electricity prices for household consumers range amongst the highest in the European Union. The situation is slightly better for industrial consumption, at roughly EUR 115 per MWh and Spain takes eighth place amongst the EU member states (notably, the United Kingdom and Italy have higher prices). However, Spanish electricity price levels are still significantly above average. Generation costs are in line with other countries. According to Red Eléctrica de España, the system operator, generation costs were at EUR 59.4/MWh in 2012, compared with EUR 60.22/MWh in 2011. This includes the wholesale market price (EUR 48.75/MWh) as well as ancillary services (EUR 4.6/MWh) and capacity payments (EUR 6.1/MWh).

With a large proportion of fed-in generation from renewables, CHP and must-run nuclear, CCGTs and coal-fired plants have become marginal suppliers. While CCGTs used to be more important in price setting than coal, this trend reversed from October 2011. According to the Comisión Nacional de Energía, the Spanish regulator, in 2012, coal's weight in price formation in the daily wholesale market was around 65% with CCGTs accounting for around 30%.

Figure 6 • German electricity price for industry (70 to 150 GWh/year)



Notes:

1. Eurostat-data before 2007 not comparable owing to change in survey methodology.
2. Non-refundable levies and taxes (local government charges, EEG charge, CHP charge; as from 2012: section-19 reallocation charge) cannot be stated separately.
3. Depending on purchasing behaviour/grid use, the non-refundable taxes and levies vary individually.

Source: Eurostat; 2013, German Association of Energy and Water Industries (BDEW), 2013.

Box 2 • Spain: tackling the electricity deficit

The main issue in the electricity and the energy sectors in Spain is the so-called electricity deficit. Although it began in 2000, the amounts of the first years were assumable for the system. However, from 2005 the annual deficit accounted for more than EUR 1 billion per year, and from 2008 to 2012, annual electricity deficits reached the EUR 5 billion mark. The deficit creates heavy damage for all stakeholders by generating a significant burden for future consumers while sending the wrong price signals to the current ones. In addition, the companies obliged to finance the deficit (only the five main utilities) have to face others' debt. Finally, the public budget is also affected by the electricity deficit, as its final financial guarantee through FADE (*Fondo de Amortización de la Deuda Eléctrica* or Fund to Pay off the Electricity Debt) jeopardises the country's solvency. It is no surprise that the main efforts of the Spanish government regarding electricity are devoted to ending this deficit.

The electricity deficit is the difference between tariffs as set by the government through the Ministry of Industry (with its different names), and the regulated costs. Spain applies European Union directives and therefore generation and retail are deregulated.[2] But transmission and distribution, together with renewables and CHP subsidies, the payment of the accumulated debt and other costs of the system, make up the regulated costs.

It might be largely due to the social sensitivity to tariff increases that the Spanish government set tariffs which did not cover all the regulated costs, generating a growing debt within the system to a few utilities obliged to assume the deficit for more than a decade. In 2009, the government created FADE in order to finance it and alleviate the main utilities' financial situations. In September 2013, the accumulated debt accounted for more than EUR 36 billion. Given that around EUR 10 billion has been paid off, the outstanding EUR 26 billion roughly equals the electricity bill of the entire country for one year, or 3% of Spain's annual gross domestic product (GDP). This amount is due to be paid by future consumers.

In order to explain how this could occur, some analysts quote the PV bubble or an excess of subsidies for renewables. As a matter of fact, photovoltaic capacity installed in Spain increased from hardly 100 MW in 2006 to more than 3 GW in 2008, with incomes over EUR 400/MWh. Currently, photovoltaic capacity is over 4 GW plus more than 2 GW of thermo-solar developed with subsidies around EUR 300/MWh. Nevertheless, accepting that part of the increase in the regulated costs has been caused by renewables' subsidies, the major cause, as stated above, is that the setting of tariffs would not break even.

Since 2010, the Spanish government has brought a series of ambitious reforms on its way to put an end to the deficit, including cutting subsidies to renewables, taxing generation activity, creating some ad hoc taxes for the different generation technologies, reducing payments for distribution and transmission, etc. The last reform, announced in July 2013, included one Royal Decree law to ensure urgent application of the measures, a new Electricity Act, seven Royal Decrees and five Ministerial Regulations, which clearly shows the ambition behind the reforms. Unfortunately, even if the deficit is overcome, the debt will remain for years.

[2] In fact, retail is not completely liberalized, as some customers are eligible to be supplied by the Last Resource Retailer, who will apply the Last Resource Tariff.

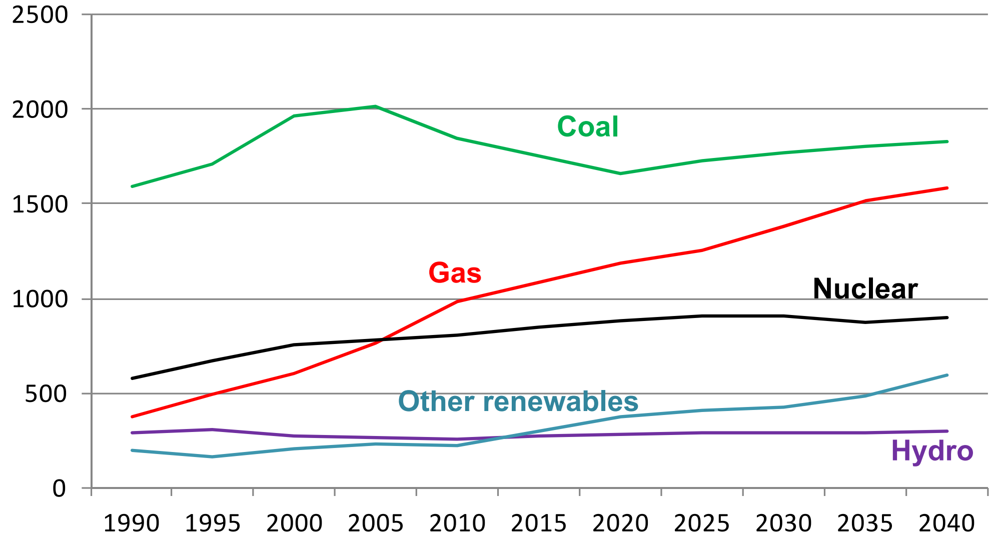
The United States

Structure of the electricity market

Coal is the leading source of electricity in the United States. The United States has an estimated 27% of the world's coal reserves distributed across more than 30 states. On a British thermal unit (Btu) basis, coal comprises 85% of America's recoverable demonstrated fossil fuel reserves, compared to 10% for gas and 5% for oil. The Powder River Basin alone has coal reserves equivalent to at least eight times the energy contained in Saudi Arabia's Ghawar oil field and 13 times more than Russia's natural gas Urengoy field.

Coal is the foundation of US electricity production and its abundance, distribution, affordability and reliability are correlated with socio-economic growth. Throughout the last century in the United States, GDP expanded twenty-fold, the population increased by 220 million people, life expectancy increased 26 years and coal provided more than 50% of the nation's electric power. Over the last decade alone, coal produced over 18 800 terawatt-hours (TWh) of electricity – more than gas, nuclear, oil, wind, and solar *combined*. The U.S. Energy Information Administration (EIA) projects that by 2020, annual electric power consumption will increase by 314 TWh and coal will still be the nation's leading source of electricity. Such beneficial electricity is the key to more people living better and living longer.

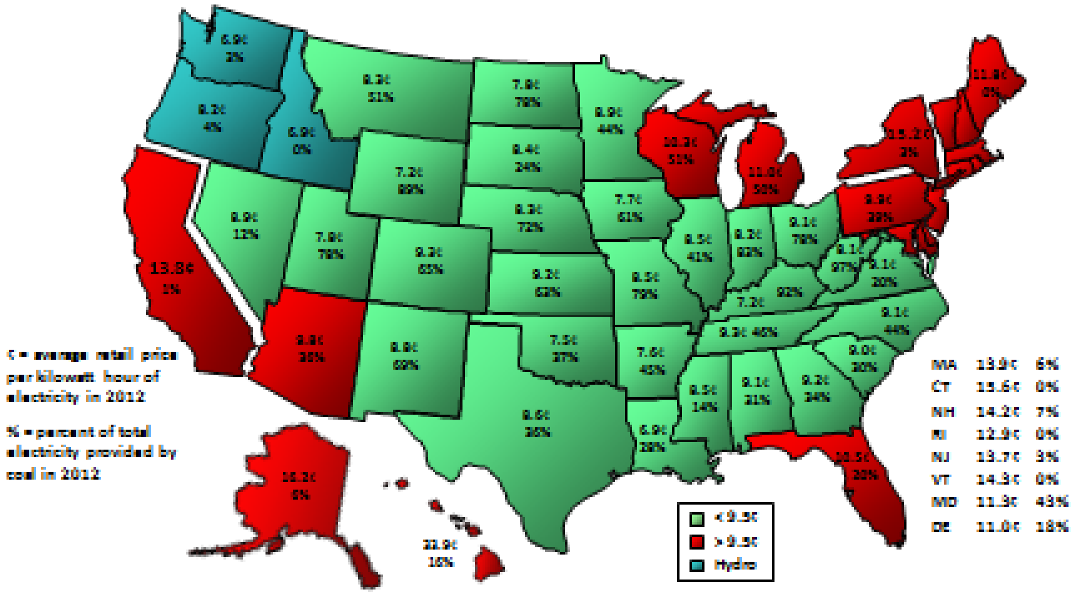
Figure 7 • Net power generation n the United States through 2040 (TWh)



Source: Energy Information Administration, *Annual Energy Outlook,* 2013.

Coal plays an essential role in maintaining low electricity prices across the United States. The fact that coal provides stable and affordable power is supported by the following map, indicating that citizens across a vast portion of the country in states heavily dependent on coal experience average retail electricity rates which are less than the national average of 9.8 cents per kilowatt-hour (kWh).

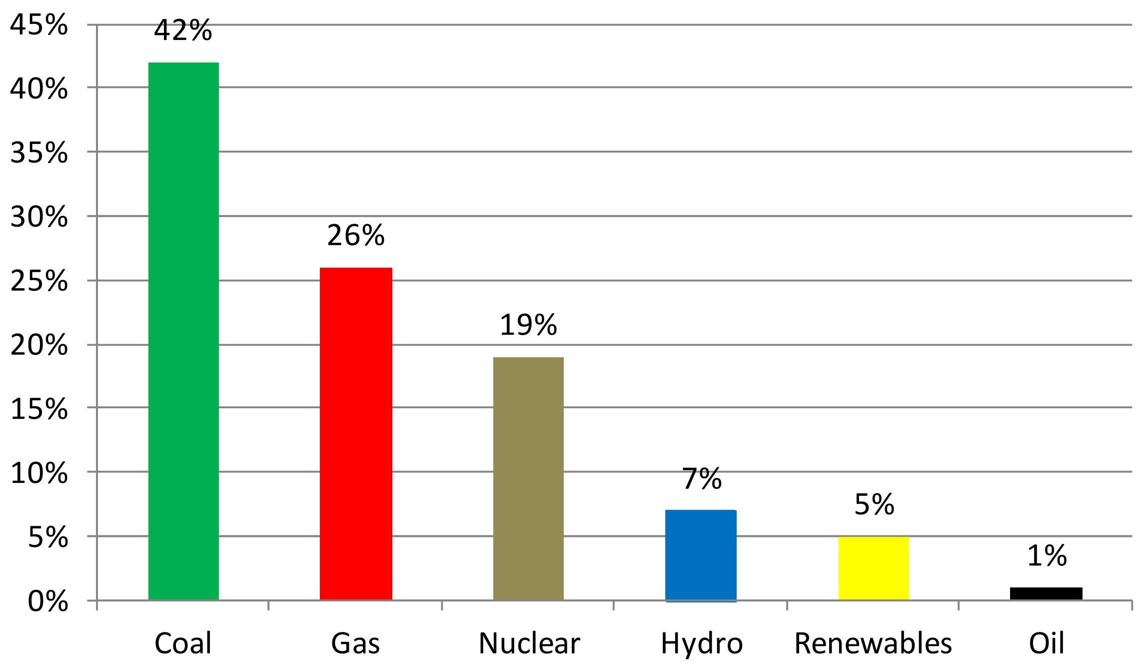
Figure 8 • States with more coal-based electricity generally have lower rates



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: Energy Information Administration, 2013.

Figure 9 • US electricity fuel sources, 2009 to 2013



Source: United States Energy Information Administration, 2013.

There are various types of power providers in the United States:

Shareholder-owned electric companies provide almost 70% of the nation's electricity. They sell electricity at retail rates to various customer classes and at wholesale rates (for resale) to state- and government-owned utilities, public utility districts and rural electric cooperatives.

Municipally-owned electric utilities are owned by the municipalities in which they operate, and are financed through municipal bonds. There are about 2 000 such utilities providing about 11% of the nation's power.

Independent Power Producers (IPPs) -- sometimes called Non-Utility Generators (NUG) -- are a power plants not owned by a public utility. There are over 1 700 IPP projects in the United States, including qualified facilities (QFs). IPPs have built a majority of new power generation in the past decade.

Federally-owned utilities are agencies of the United States' federal government involved in generation and/or transmission of electricity, most of which is sold at wholesale prices to local government-owned utilities and to shareholder-owned companies. They provide approximately 6% of US electricity. These government agencies are the Army Corps of Engineers and the Bureau of Reclamation, which generate electricity at hydroelectric projects. In addition, the Tennessee Valley Authority produces and transmits electricity within the Southeast region.

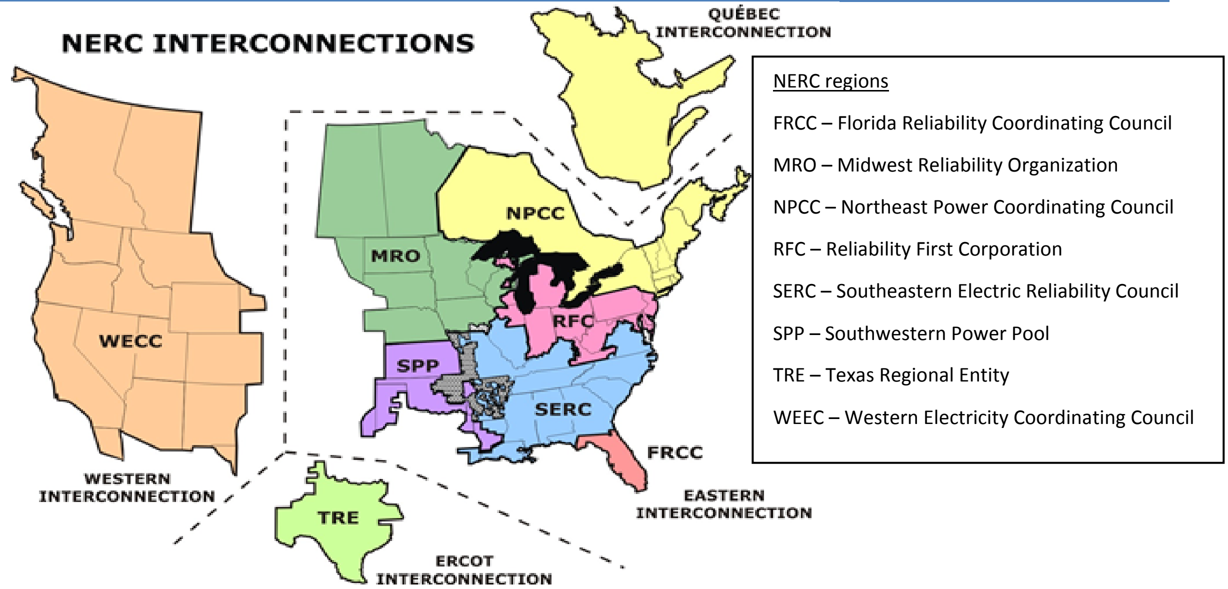
Electric cooperatives were constituted via the Rural Electrification Administration in 1936. They provide about 13% of the nation's power. There are upwards of 1 000 cooperatives in the United States but most are distribution only. About 60 of them are generation and transmission cooperatives that provide wholesale power to their member distribution cooperatives.

Industrial: There are thousands of industrial sites in the United States and. many have local energy plants that produce steam and electricity.

The United States does not possess a national power grid, but instead has three main power grids:

- Eastern Interconnection
- Western Interconnection
- Texas Interconnection

Figure 10 • NERC interconnections



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.
Source: North American Electric Reliability Corporation, 2013.

The Eastern and Western Interconnections have limited interconnections, and the Texas Interconnect is only linked to the others via direct-current lines. Both the Western and Texas

Interconnections are linked with Mexico. The Eastern and Western Interconnects are linked with Canada. The North American Reliability Corporation (NERC) works with eight regional entities to improve the reliability of the bulk power system.

The United States imports and exports electricity from and to Canada and Mexico. In 2011, the US net electricity imported was 37.3 million megawatt-hours, representing less than 2% of total generation. Canada is the largest electricity trading partner with the United States importing over 51 million megawatt-hours and exporting slightly over 14 million megawatt-hours.

Market design

The states in America follow different regulatory models. Many states follow a cost-plus regulated model but some have deregulated. In regulated states, utilities are vertically integrated and prepare integrated resource plans to serve their load. Supply and distribution rates are set through economic regulation. In deregulated states, which account for approximately 37% of US electricity, supply rates are set by markets, generally on a merit-order principle. Distribution services are still fully regulated and distribution rates are set through economic regulation. Deregulated utilities do not prepare integrated resource plans; however, the states where they are located retain some authority to direct generation and demand-side resources.

United States utilities are regulated by both federal and state regulatory bodies:

- The Federal Energy Regulatory Commission (FERC) regulates wholesale electricity markets and interstate transmission services
- State utility commissions regulate retail sales, distribution services, siting issues, and a variety of associated activities.

During the 1990s, the United States experienced several major power outages. In an effort to mitigate this problem, the FERC implemented *Order 2000,* providing for the creation of regional wholesale markets. Regional Transmission Organisations (RTOs) and Independent System Operators (ISOs) have organised market regions in which they operate a day-ahead market and/or real-time energy and ancillary services markets. The merit order principle applies to day-ahead markets. Independent market monitors enforce market rules and identify market power problems.

Carbon dioxide is not priced in the United States. On 20 September 2013, the United States Environmental Protection Agency (EPA) proposed a set of regulations under its New Source Performance Standard (NSPS) that would arbitrarily set a limit on CO_2 emissions from coal-based electrical generation at 1 100 lb/CO_2 per MWh. This standard is currently not achievable with even the most advanced coal-fuelled combustion generation technology commercially available. The EPA acknowledges the economic impact of the proposed regulation, stating that “DOE/NETL estimates that using today’s commercially available CCS technology would add around 80% to the cost of electricity for a new pulverized coal (PC) plant.” Alternative energy sources are higher cost and unable to replace coal at scale.

The EPA’s proposed CO_2 order applies only to new units. With respect to the existing fleet, it is unlikely that the EPA would follow the same path, given the reliability and cost issues associated with alternative fuels. Furthermore, the EPA proposal is highly controversial, breaks new legal ground, and is certain to be appealed if issued. On 27 March 2013, the United States Senate unanimously passed a budget resolution amendment stipulating that any carbon emissions standard must be cost-effective, based on the best available science and benefit low-income and middle-class families.

Power plant fuel supply

In 2012, the United States produced 915 Mt, exported 113 Mt, and imported 8 Mt of coal. A total of 810 Mt was domestically consumed, of which 92% was used to generate electricity.

Over the past 150 years, the United States has built a vast infrastructure for extracting, transporting and utilising coal for electric power, as the following map indicates.

Figure 11 • Coal-fuelled electricity generation supply chain in the United States

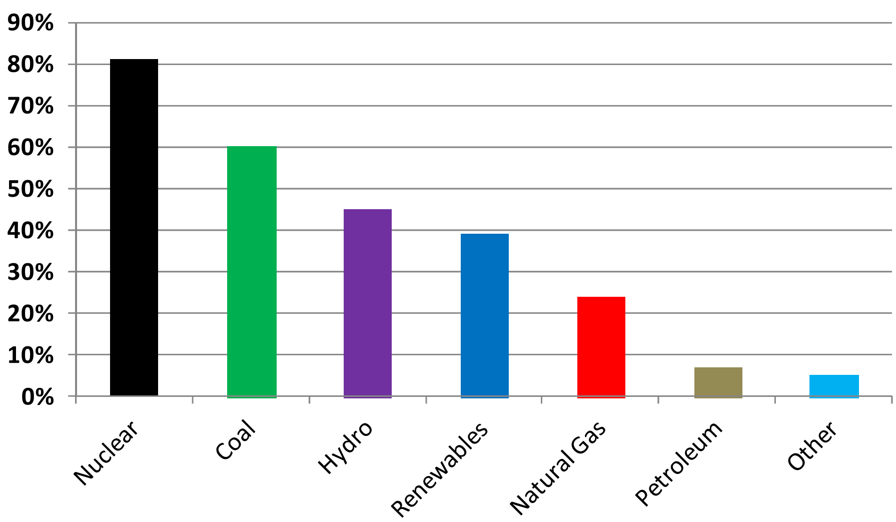
- 1 200+ active coal mines
- 95 000 miles of Class 1 railroads
- 12 000 miles of commercially navigable waterways
- 1 400 coal-based generators with 343 GW nameplate capacity

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: United States Energy Information Administration, 2013.

The United States' coal-fuelled electricity generation supply chain is unmatched in the world. Research at Penn State University estimated that the United States coal power supply chain provided over USD 1 trillion in gross economic output, 7% of US GDP, 6.8 million jobs (5%+ of the US workforce) and USD 362 billion in annual household income. Coal power plants are supplied by both long-term and spot market contracts. Only a handful of power plants have dedicated mines. Furthermore, as the heart of US competitiveness, coal has a long history of availability. In 2011, for instance, coal power plants in the United States had a 60% utilisation rate.

Figure 12 • Utilisation rates



Coal accounts for 30% of generation capacity and produces 42% of America's electricity.

Gas comprises 40% of capacity and produces 26% of the nation's power.

Source: Energy Information Administration, 2013.

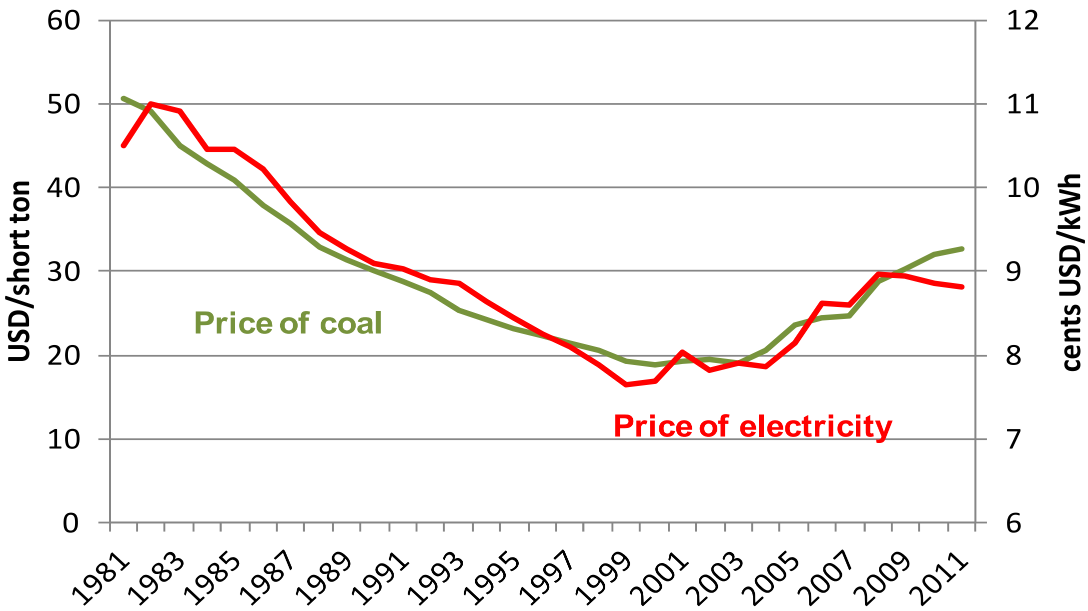
Coal makes these extensive contributions with minimal subsidies. Data from the United States Department of Energy indicate subsidies to solar electricity per MWh are USD 775.64, while wind subsidies are USD 56.29. The nuclear subsidy is USD 3.14, hydropower USD 0.82 and the oil, gas and coal subsidy is only USD 0.64.

Development of hard coal and electricity prices

From 1980, the average coal price trended downward until roughly 2005, when new United States EPA regulations exerted upward pressure. In the past few years, increased shale gas production has ed to a reduced cost of gas to produce electric power but the issue of volatility of price remains. In June 2011 the price of gas for power production was USD 5.20 per million cubic feet (mcf). By June 2012, the price had declined 38% to USD 3.20 per mcf. By June 2013, however, the price had increased by 42% to USD 4.56 per mcf. The following graph is proof positive that long term stable coal pricing has been a major factor in the stability of US electric power prices. This pricing has provided competitive advantage, enabling energy-intensive manufacturers and industries to make long-term investment decisions.

The price of coal to produce electricity was un-changed from 2011 to 2012 and declined 1% through June 2013.

Figure 13 • Annual real price of coal, price of electricity for all sectors



* Real USD 2005

Source: Energy Information Administration, 2013.

Table 5 • Average retail price of electricity, by end-use sector (cents per kWh)

Year	Residential	Commercial	Industrial	All Sectors
2000	8.24	7.43	4.64	6.81
2001	8.58	7.92	5.05	7.29
2002	8.44	7.89	4.88	7.2
2003	8.72	8.03	5.11	7.44
2004	8.95	8.17	5.25	7.61
2005	9.45	8.67	5.73	8.14
2006	10.4	9.46	6.16	8.9
2007	10.65	9.65	6.39	9.13
2008	11.26	10.36	6.83	9.74
2009	11.51	10.17	6.81	9.82
2010	11.54	10.19	6.77	9.83
2011	11.72	10.23	6.82	9.9
2012	11.88	10.12	6.7	9.87

Source: United States Energy Information Administration, 2013.

The cost of energy is an increasingly important issue in the United States since, over the last decade, energy bills for the middle class have nearly doubled as a percentage of after-tax income. During this period, the nominal price of coal to produce electric power averaged just USD 1.78 per mBtu, while the price of natural gas averaged USD 6.07 per mBtu.

Coal prices were relatively stable compared to the high volatility of gas prices. In mid-2003, gas to produce power was USD 3.61 per thousand cubic feet; by 2005 it had reached USD 6.69 and spiked to USD 12.41 in 2008. During the decade, coal never exceeded the equivalent price of USD 2.50.

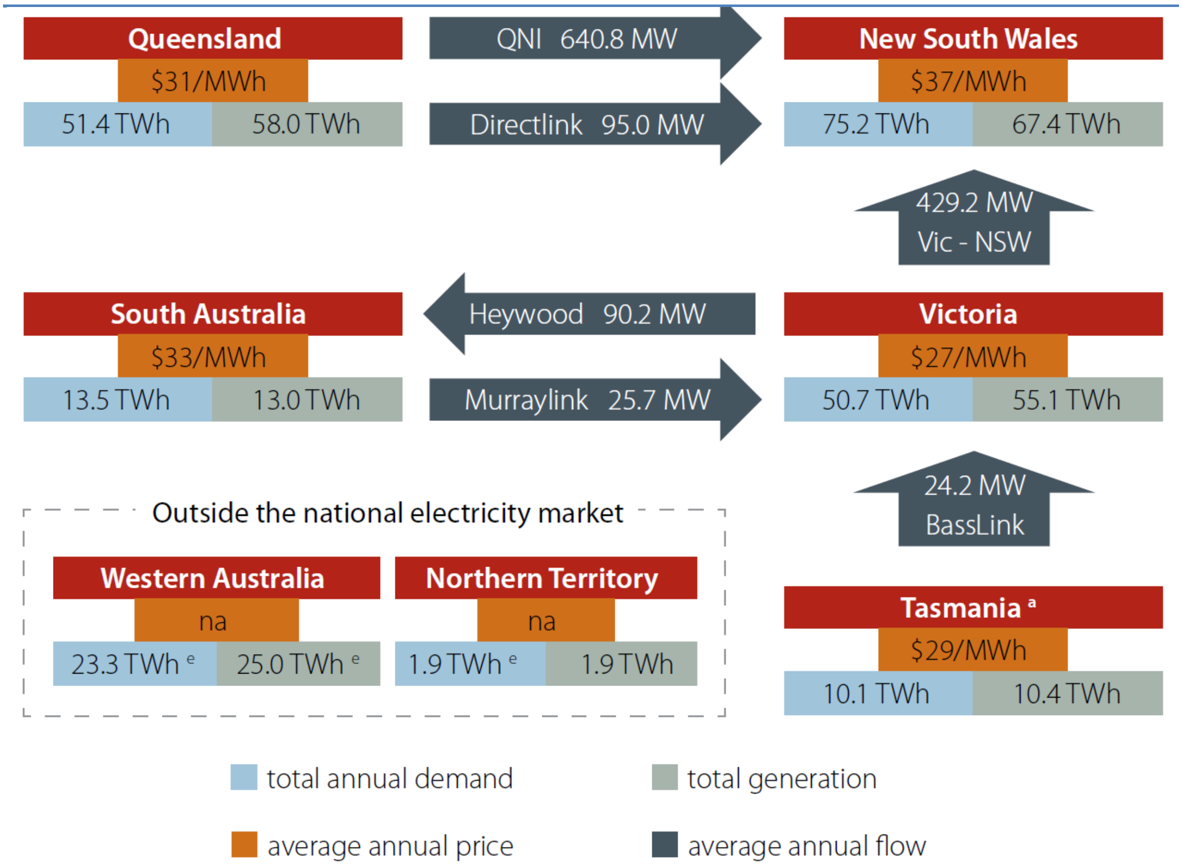
The United States has extensive experience with the adverse impact of high and volatile natural gas prices on families, businesses and institutions. Not only does the price of natural gas increase, but electricity rates rise as well. Coal has served as an important buffer, with a proven ability to moderate electricity rates throughout periods of volatile and rising natural gas prices.

Australia

Structure of the electricity market

Australia's electricity supply industry is split across geographical regions due to large distances that make full interconnection uneconomic. It is dominated by the National Electricity Market (NEM) – the world's longest interconnected power system – on the east coast of Australia. This market covers five states which together consume nearly 90% of Australia's 226 TWh annual electricity demand. The remainder of demand comes from Western Australia, which operates a separate market in the south-west of the state, and the northern territory which operates a separate supply system.

Figure 14 • Australia's electricity market structure for 2010/11

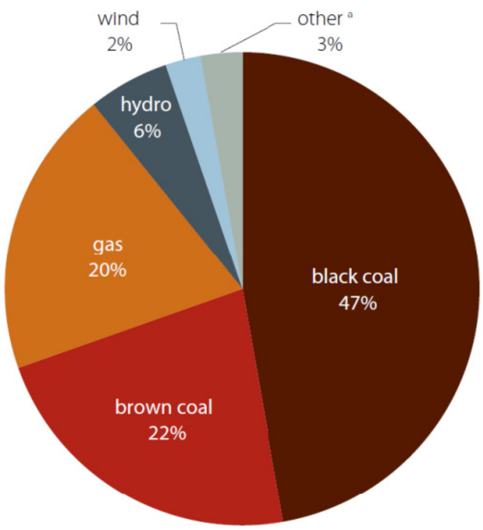


Source: Australian Bureau of Resource and Energy Economics (BREE).

More than 69% of Australia's electricity is supplied by coal. This is predominantly hard, or black, coal which makes up 47% of Australia's electricity supply. This mix is largely determined by geographical resource allocations. The southern states, Victoria and South Australia, have abundant lignite resources and see most of their generation coming from this source. New South Wales (NSW), Queensland and Western Australia have abundant hard coal resources. Hydro generation is sourced from the mountainous south-east of NSW as well as from Tasmania. Although Australia has abundant gas resources, the fuel has not been developed as a power generation source on a large scale due to the cost-competitiveness of coal in Australia and its predominantly remote western Australian location until recent discoveries in eastern Australia.

The four largest generating companies in the NEM control 52% of the generation capacity. The remainder of the capacity is owned by 11 market participants, with a number of smaller companies also providing small amounts of generation capacity. The hard coal generators in Australia are controlled by eight companies. Most of these stations form part of larger portfolios, while only two are independent generators.

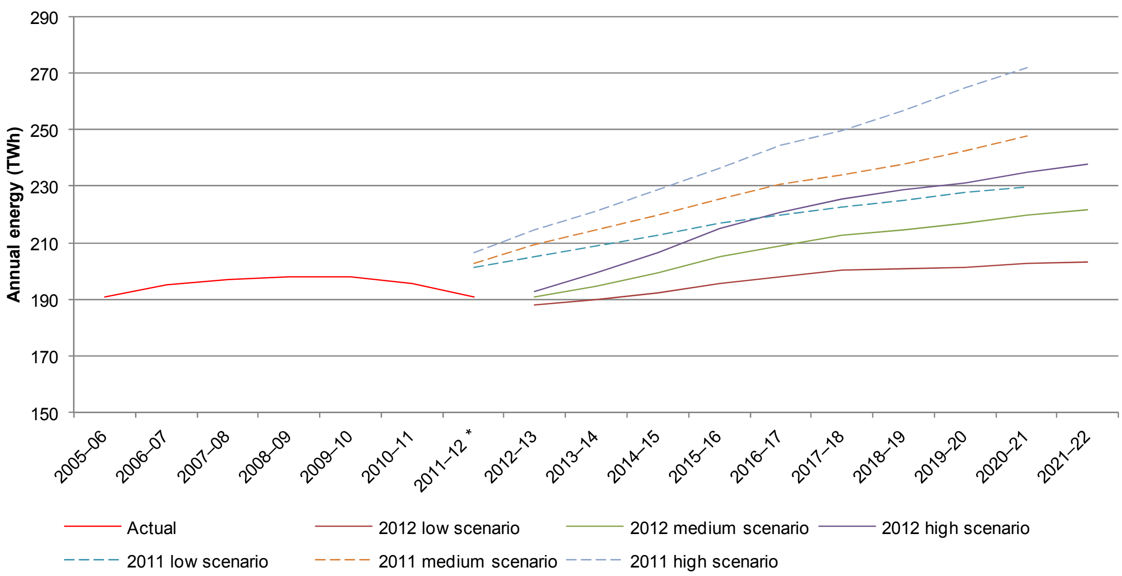
Figure 15 • Fuel sources for electricity in Australia, by energy source 2010/11



Note: "Other" includes oil, bioenergy, solar PV and multi-fuel fired power plants.
Source: BREE.

Electricity demand has been falling in the east coast NEM due to poor economic conditions for the manufacturing sector, fuel switching, growth of renewables, strong energy efficiency policies and retail price increases. The Australian Energy Market Operator (AEMO) expects a return to growth from 2013/14. However there are substantial risks to this outlook, not least of which is the continuing strength of the Australian dollar.

Figure 16 • Historical and forecast energy growth in the NEM



Source: Australian Energy Market Operator, 2012.

Although the forecast is for a return to growth in electricity demand, the current federal government policy is for 41 000 GWh of supply to come from renewable sources by 2020 under the Renewable Energy Target Scheme. This is likely to take a significant portion of the growth from hard coal generators and militate against more substantial investment in new gas generation.

Market design

The National Electricity Market (NEM) provides a framework for competition in the electricity supply industry. The NEM is a gross pool, energy only market. Generators submit bids for the dispatch of their capacity for each 30-minute trading period throughout the day. The Australian Energy Market Operator (AEMO) stacks the bids in order of increasing price and the wholesale pool price is then set at the level where demand is met.

Generators typically submit cost-reflective bids with a tendency towards short-run marginal cost during periods when there is excess generating capacity. At peak times, pool prices are limited to AUD 12 900/MWh. This high price ceiling has produced significant volatility during high demand periods, which has supported returns to generators much closer to average cost. However, with demand growth turning negative, excess supply has reduced volatility and returns to generators are decreaasing.

The NEM pool price is supported by a financial hedging market that provides derivatives via OTC and futures contracts. All long-term contracts for the supply of electricity at the wholesale level are financial derivatives with the NEM pool price as the underlying commodity.

Australia has implemented a carbon tax of AUD 23 per tonne of CO_2. This fixed price mechanism will remain in place for another two years, with prices rising to 24.15 in 2013/14 and then to AUD 25.40 in 2014/15. Beyond this period the carbon pricing scheme will move to a traded market linked to the EU ETS. Significant political risk surrounds this scheme, as the current federal government has introduced legislation to abolish the carbon price from 1 July 2014. However, the government is unlikely to have the required numbers in the senate to pass the legislation until 1 July 2014 and has indicated that if passed after this date, the changes would apply retrospectively.

The carbon price adds to the costs of all generators according to their emissions intensity. Wholesale electricity prices have responded as expected by increasing broadly in line with the average emissions intensity of dispatched generation. This has caused a substantial reduction in revenue for hard coal generators, since the average emissions intensity is below that of most hard coal plant. Furthermore, lignite generators were compensated for the imposition of a carbon price but hard coal generators were not. This has not impacted the wholesale price of electricity, but has given a competitive boost to the owners of lignite generators.

The utilisation factor of generating plant in Australia varies by ownership and plant type. However, utilisation factors typically range between 80% and 95% for lignite generators and between 50% and-85% for hard coal generators. Gas plants operate at much lower utilisation levels than this. This aligns with the position of the plant in the merit order of the NEM, which is determined by fuel cost and carbon cost. Carbon costs have not been set at a high enough level to cause merit-order switching between lignite and hard coal generators, which means that utilisation remains broadly similar after the incorporation of the carbon tax in generator cost structures. However, capacity at a number of higher-cost black coal generators has been mothballed until wholesale demand has improved, and last year there were a small number of closures of relatively old, high-cost plants.

Prior to the downturn in demand, gas and hydro plants set the price during the peak. However, the demand downturn has resulted in an increase in excess capacity. Peak period price setting is now dominated by the relatively higher-cost hard coal plants, with off-peak period pricing coming from lignite or (other) hard coal plant with lower-cost fuel supplies.

Power plant fuel supply

Australia has a mix of fuel supply arrangements for power stations. A number of hard coal power stations in Queensland are supplied by captive mines. These mines supply coal to the power stations at, or near, the production cost of fuel. The remaining hard coal power stations in Australia are predominantly supplied by rail or by conveyor from independent coal mining operations. This introduces competitive supply arrangements, although some have long-term contracts in place out to the 2020s, and in one case, to 2032, and have limited options to export coal due to infrastructure or regulatory constraints. So they consider themselves to be “captive”.

Hard coal generators in New South Wales (NSW) and Queensland are located in close proximity to mainly export-oriented mines and infrastructure. Most coal that is supplied to domestic power stations via rail is therefore exposed to an export opportunity cost. This has meant that new domestic coal supply contracts are negotiated around the net-back export parity price. As export prices have risen in recent years, domestic coal prices have increased accordingly. While this dynamic affects marginal cost, the average fuel cost to generators is often lower due to long-term contracts that were negotiated prior to high export coal prices.

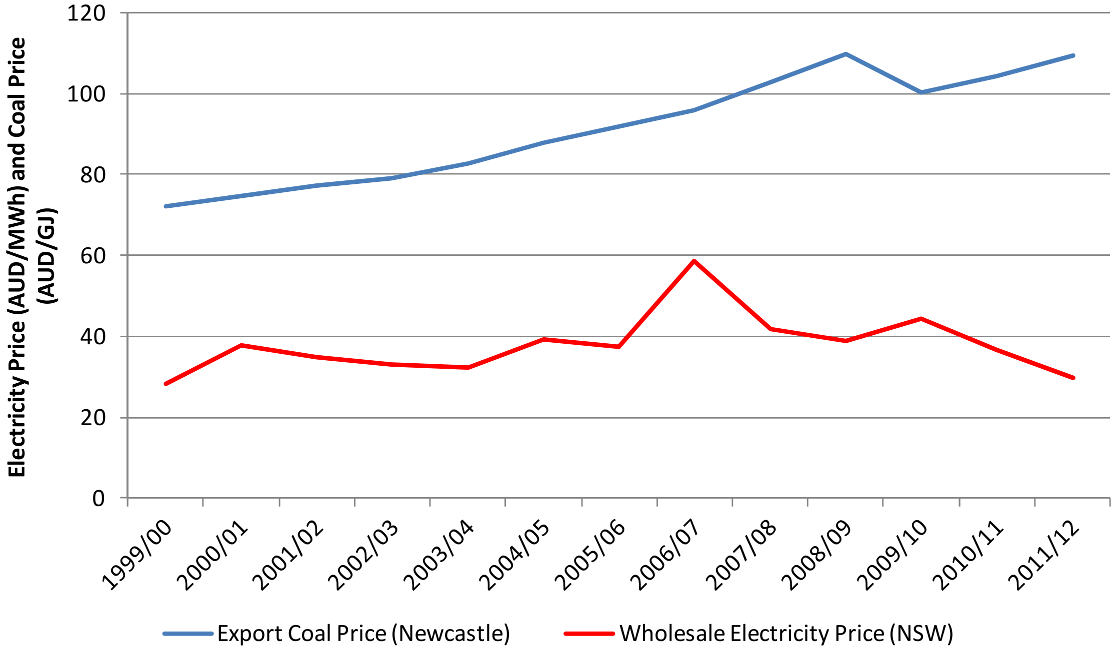
Coal costs for Australian hard coal plants range from AUD 0.75/GJ to an upper limit equivalent to the net-back export price. This has been well over AUD3/GJ but has now retreated below these levels due to lower international thermal coal prices. Marginal coal costs for lignite plant range from AUD 0.10/GJ to AUD 0.60/GJ, with gas supply costs historically near AUD4/GJ for combined-cycle plant and AUD6/GJ for peaking plant.

Hard coal plants faced pressure from proposals for gas-fired generation with the development of coal seam gas in both New South Wales and Queensland, along with the imposition of a carbon price. However, this pressure appears to have been relieved due to the development of an LNG export industry on the east coast of Australia. Domestic gas prices are expected to increase to reflect net-back export parity pricing which, at current LNG prices, will likely be between AUD 8-10/gigajoule (GJ). This, coupled with the Renewable Energy Target requirements, (which act to crowd out gas), will make gas plants uncompetitive in a low-growth environment, unless the carbon price rises significantly. Moreover, the finance industry is unwilling to finance a new black coal-fired generator in the absence of a long-term strategy (*i.e.* 30-plus years) to deal with the carbon price.

Development of hard-coal and electricity prices

While coal prices and wholesale electricity prices increased substantially between 2000 and 2007, wholesale electricity prices (nominal terms) in Australia decreased between 2006 and 2012, whereas coal prices continued to increase during this period.

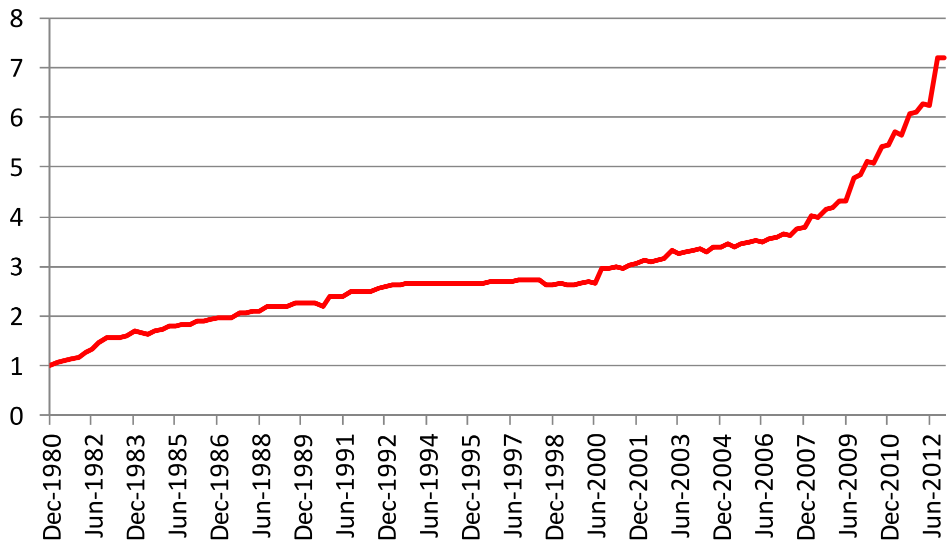
Figure 17 • NSW electricity price (time-weighted, all periods) and export coal price (FOB ex-Newcastle)



Source: Australian Bureau of Statistics, 2013.

The primary driver behind electricity prices in the NEM is the supply/demand balance. This is demonstrated by the peak in 2006/07 and the decline in spot prices from 2009/10. The 2006/07 spot price maximum was brought on by a significant drought that caused water shortages to a number of NEM generators. The result was capacity withdrawal and an increased opportunity cost of water. These factors, combined with high demand, resulted in a tight supply/demand balance and high prices during all periods of the year. However, the recent decline in demand has resulted in a significant capacity overhang and supply that far outweighs demand. This has caused competition for dispatch volume. This situation has been exacerbated by renewable generation which is dispatched ahead of gas and coal generation, causing the price to be set lower on the supply curve.

Figure 18 • Retail electricity price index

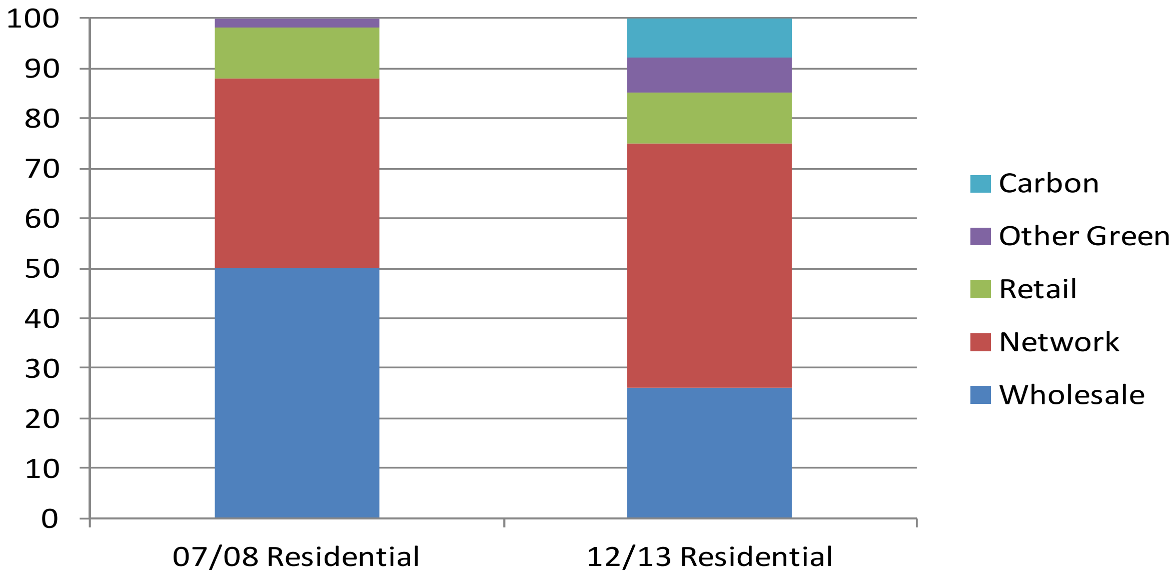


Source: Australian Bureau of Statistics.

At the consumer level, the picture is very different. Retail electricity price have been rising in recent years. However, again this is not due to the impact of coal prices. Increased expenditure on transmission and distribution networks has been the primary cause of the sharp increase in retail prices from 2006.

This is demonstrated in the different price components for retail customers in 2011/12 and 2012/13 (Figure 19). The clear increase in network costs has contributed to the final price increases. Another component that has been increasing is the green cost, which reflects carbon costs and costs due to the mandating of renewables through the Renewable Energy Target. However, the increase in this component has been overshadowed by the network component.

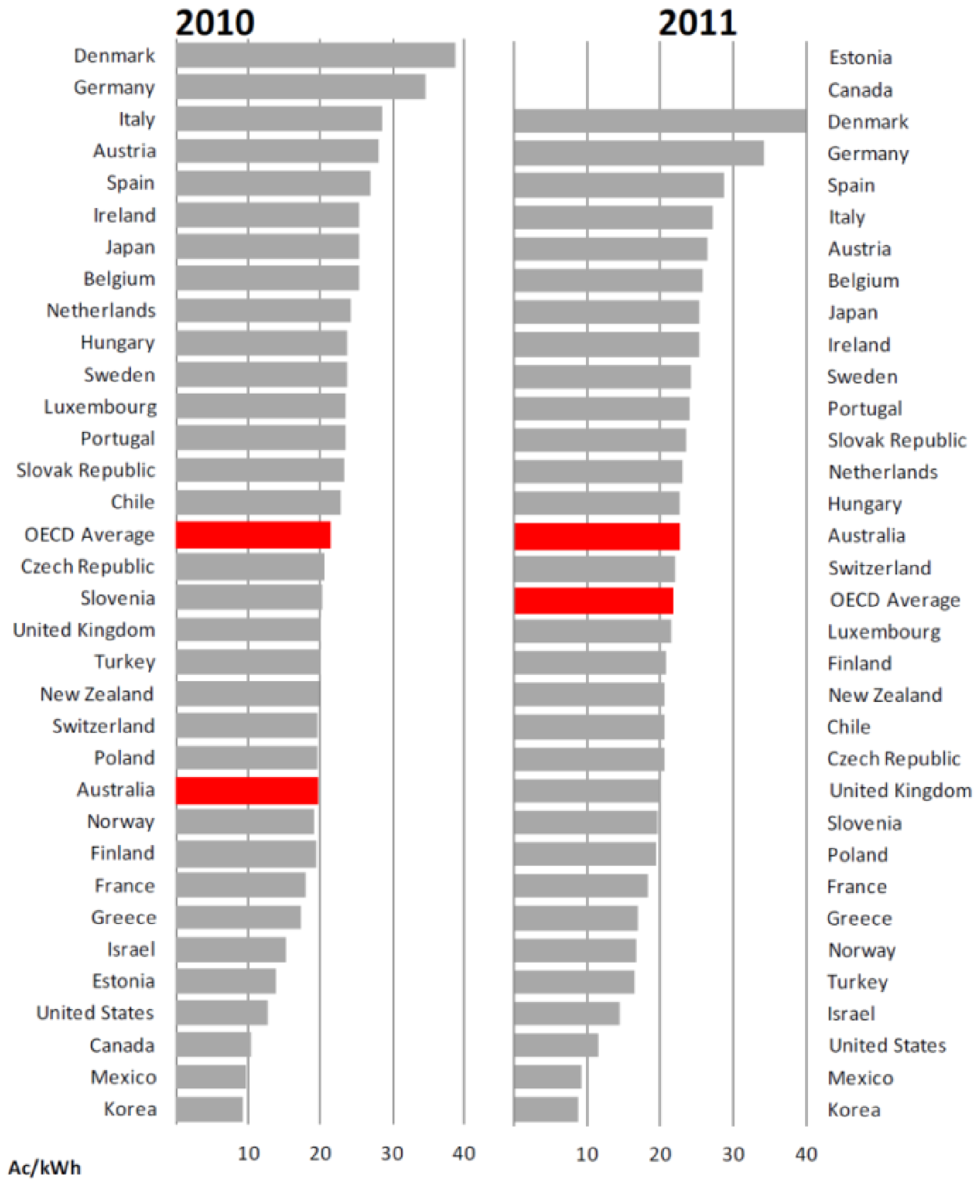
Figure 19 • Retail electricity price components



Source: NSW Independent Pricing and Regulatory Tribunal (IPART).

Even with these increases, the retail price of electricity in Australia is well below many comparable nations. This can largely be attributed to the relatively high level of coal-fired generation.

Figure 20 • Retail price of electricity in Australia in comparison



Source: Senate Select Committee on Electricity Prices, Department of Resources, Energy and Tourism, 2012.

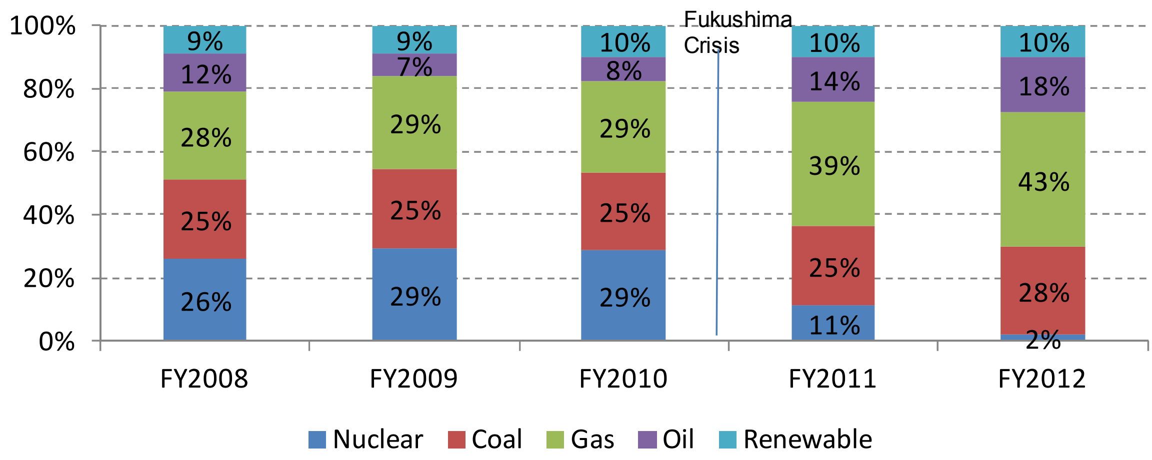
Japan

Structure of the electricity market

Japan's electricity market is divided into ten regional areas. A total of ten regional power utilities monopolise generation, transmission and distribution in each area. The ten power utilities account for 87% of Japan's total electricity supply.

Japan's energy mix in power generation has significantly changed in the wake of the Fukushima crisis. Only two nuclear power units out of a total of 50 are currently operating in Japan. Gas- and oil-fired power plants are the main replacements for nuclear power. The Japanese energy mix before and after the Fukushima crisis is shown in Figure 21.

Figure 21 • The Japanese energy mix in power generation



Source: Federation of Electric Power Companies of Japan, 2013.

As an island country, the Japanese power system is independent and unconnected from its neighbours.

The government's energy policy after the Fukushima crisis is still uncertain. However, power consumption is generally expected to be constant or to increase gradually.

Market design

The regulated sector is supplied by ten regional power utilities and governed by state regulation. The electricity prices in such a market are determined on the full-cost pricing principle (to ensure investment return and full recovery of variable costs) and are subject to the government's approval.

Although deregulation of the retail sector has progressed, and approximately 62% of the electric power consumers have the choice to purchase electricity from suppliers other than the ten regional monopolies, as little as 2% of the country's generated power is supplied through the deregulated market.

Japan's power market design has been re-examined after the Fukushima crisis. The government has made policy proposals to fully deregulate the retail power market by 2016.

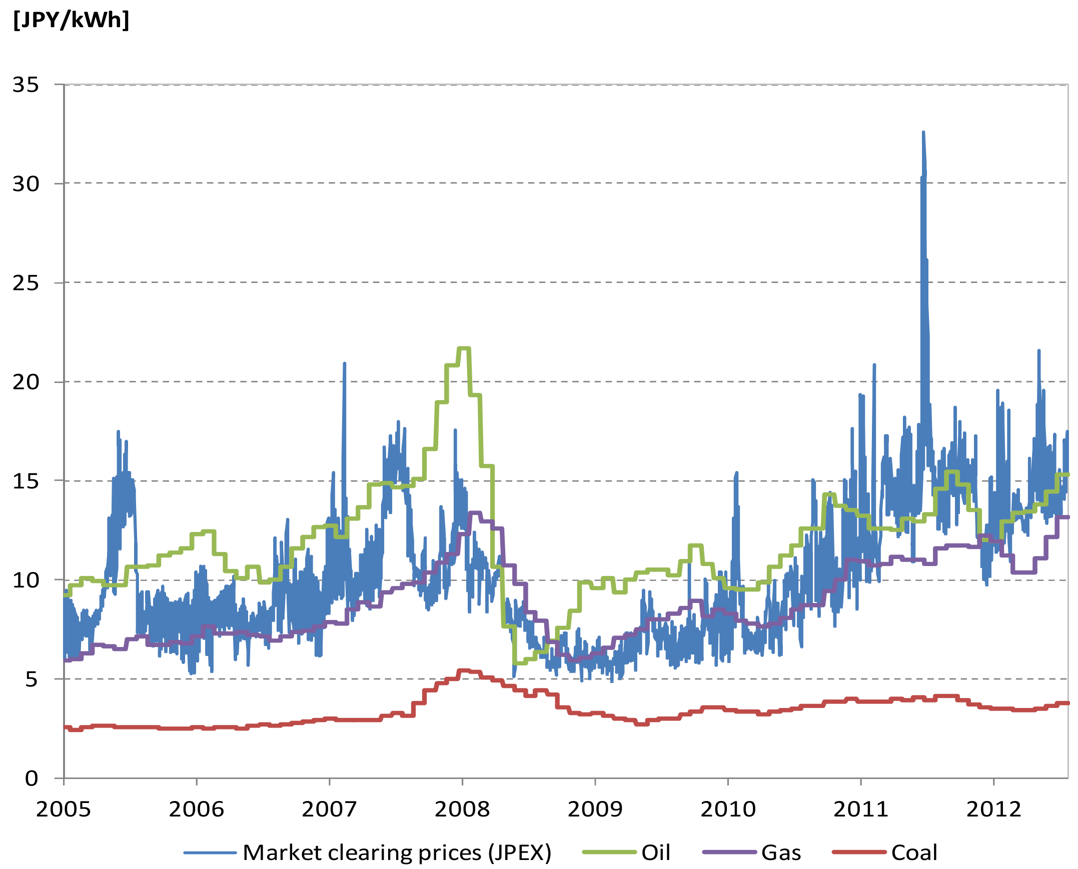
In addition, there is a fuel cost adjustment system in the regulated sector. This adjustment is based on the approved energy portfolio (nuclear, coal, gas, oil and renewable) of each power utility and calculated in proportion to the Japanese customs statistics. Regulated power prices are adjusted by these fuel costs. In the deregulated sector, a similar fuel cost adjustment system is often employed between the many electricity power consumers and the ten regional power utilities

The electricity power tariff is set based on full-cost calculations with consideration of merit order.

In the deregulated power market (Japan Electric Power Exchange, JEPX), electric power is bid freely, giving the effect of a merit order.

Currently power market clearing prices are determined by gas-fired power generation, which has higher prices than coal-fired and lower prices than oil-fired generation. However, when nuclear power generation was base load (before the Fukushima crisis), coal-fired power generation determined electricity clearing prices in off-peak demand at night and in spring and autumn.

Figure 22 • Market clearing price and generating costs of each fuel



Note:Fuel cost calculation CIF prices : Japanese customs statistics

Thermal plant efficiency: 40% Calorific value: coal 25.7MJ, oil 38.2MJ, gas 54.6MJ

Sources: Japanese customs statistics (CIF prices); Japan Electric Power Exchange; (market clearing price) (JPEX), 2013.

Carbon dioxide costs have been added onto the electricity prices as an environmental tax since October 2012. Japan does not have a cap and trade system. Each fossil fuel was taxed at its own rate as energy tax until 2012. Now each fossil fuel has an added-on 289 JPY/t(CO_2) tax. Each fuel tax is shown in the table below.

Table 6 • Tax on each fossil fuel

	Energy tax	CO_2 tax	Total
Coal	700 [JPY/t-coal]	670 [JPY/t-coal]	1 370 [JPY/t-coal]
Gas	1 080 [JPY/t-gas]	780 [JPY/t-gas]	1 860 [JPY/t-gas]
Oil	2 040 [JPY/kl-oil]	760 [JPY/kl-oil]	2 800 [JPY/kl-oil]

Source: Ministry of Finance, Japan, 2011.

In the regulated market, the price is set based on a weighted average cost of various generations. It appears that 70%, actual value in 2011, of coal-fired power plants' yearly output contributes to the electricity price-setting. In the deregulated market, coal-fired power plants do not have direct influence on power pricing.

Power plant fuel supply

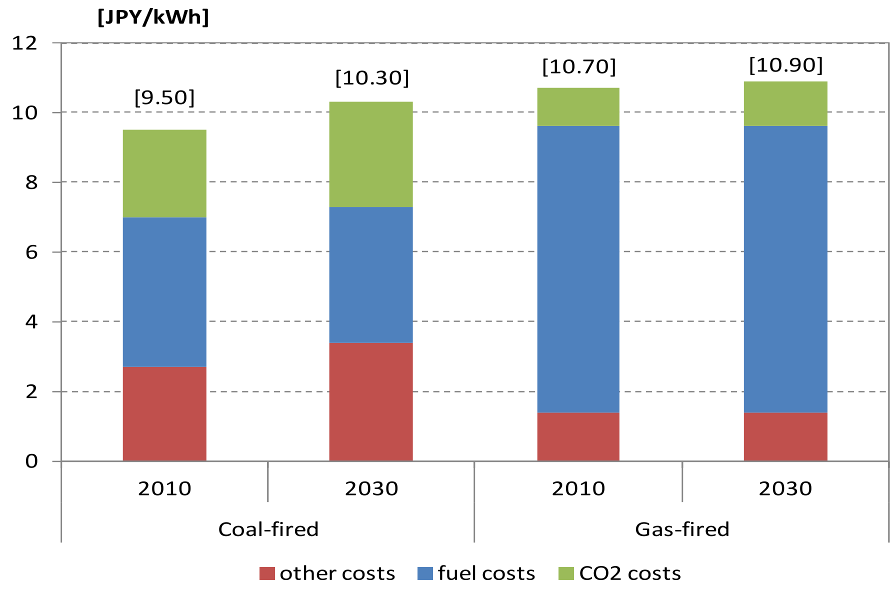
Japanese coal imports from overseas accounted for 99.4% of coal supplies in 2011. Imports from Australia, Indonesia and Russia accounted for 96% of hard coal imports.

Coal-fired power plants pay market prices to suppliers. Most hard coal used in Japan is imported. Coal-fired power generators pay both free on board (FOB) and freight for imported coal. Most coal imports are on long-term contracts. Some are on a floating pricing linked to indexes such as global coal.

The marginal cost of coal-fired power plants is less than gas-fired plants in Japan; therefore coal-fired power plants have higher utilisation ratios.

Carbon dioxide costs of coal-fired generation were higher than gas-fired plants in 2010 and will be higher in 2030, according to national policy. However, the total electricity costs of coal-fired plants will still be less than gas-fired plants in 2030.

Figure 23 • Electricity generation full costs of coal-fired and gas-fired in 2010 and 2030



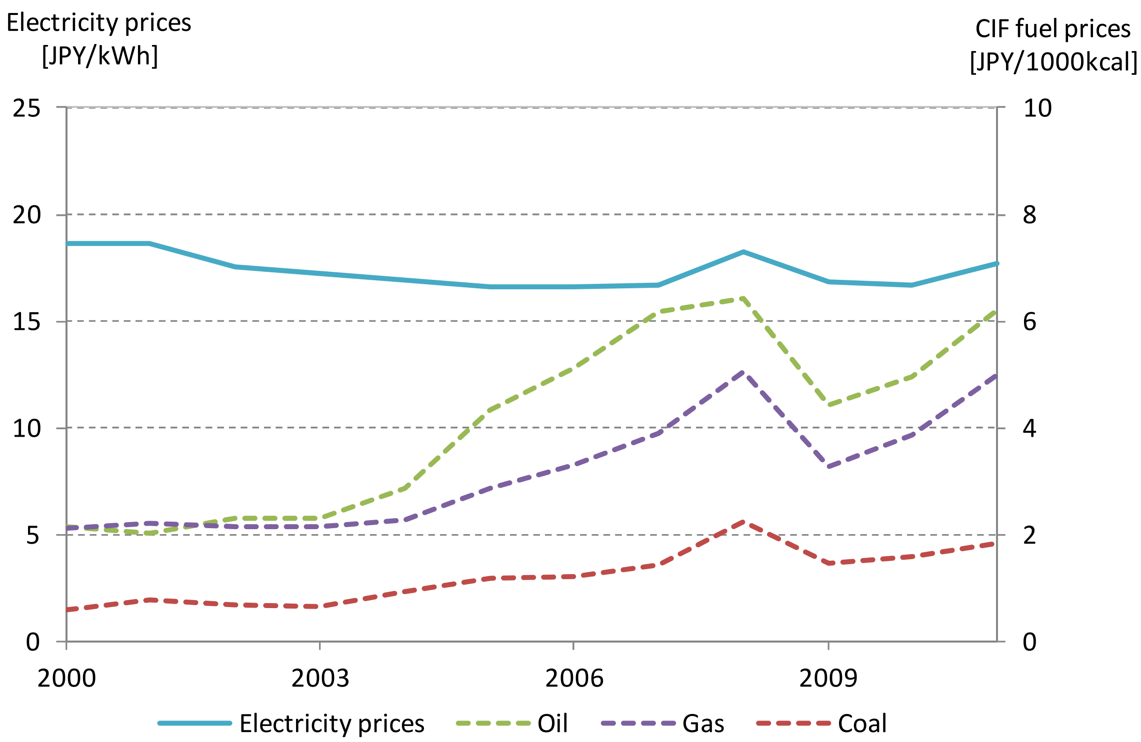
Note: Power plants are assumed to be most modern. CO_2 costs are calculated as modelling costs in 2011 by using actual prices and estimates in the typical European markets of CO_2. These costs were calculated before Japan's introduction of the current CO_2 tax. Therefore the current CO_2 tax is not included in the modelling sots. Fuel costs are based on IEA estimates.

Source: National Policy Unit, Japan, 2011.

Development of hard-coal and electricity prices

Since 2000, electricity prices had been on a downward trend (until the Fukushima crisis) because the deregulation of the retail sector had progressed since 2000 and the ratio of fixed costs had been reduced. During times of soaring fuel prices, such as in 2008, electricity prices rose temporarily. After the Fukushima crisis, electricity prices increased because the energy mix changed significantly and more electricity was coming from higher-cost generating plants.

Figure 24 • CIF* prices of fossil fuel and electricity prices in Japan



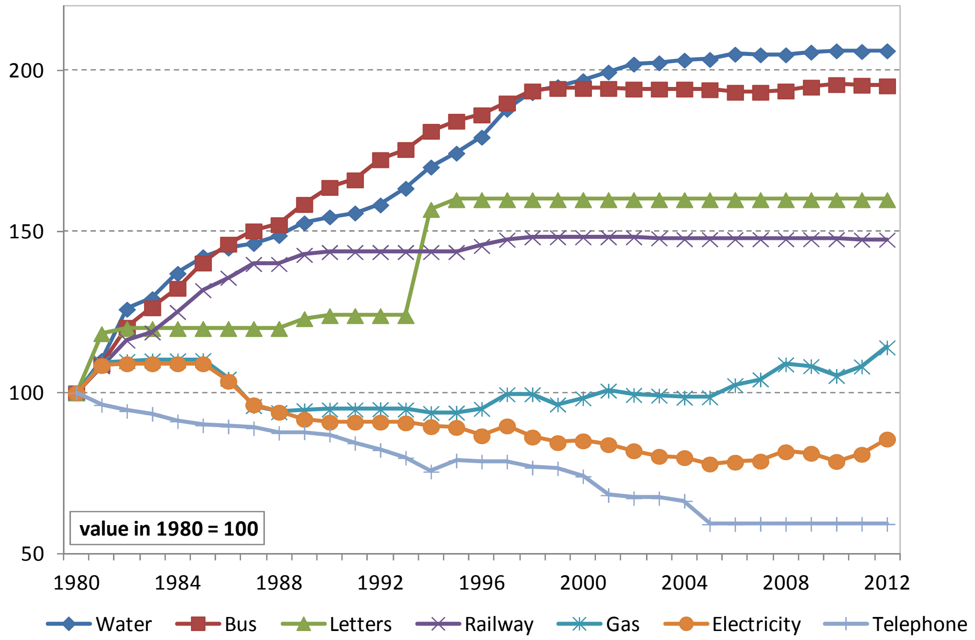
*CIF: cost, insurance and freight

Source: The Institute of Energy Economics Japan. 2013.

In the *regulated* market there is a degree of correlation between coal and electricity prices because electricity prices are based on the full-cost pricing principle and the fuel cost adjustment system. This correlation is interpreted as causation.

In the deregulated market, there is no strong correlation between coal and electricity prices. This is because gas-fired power plants determine the electricity market clearing price in the wholesale market.

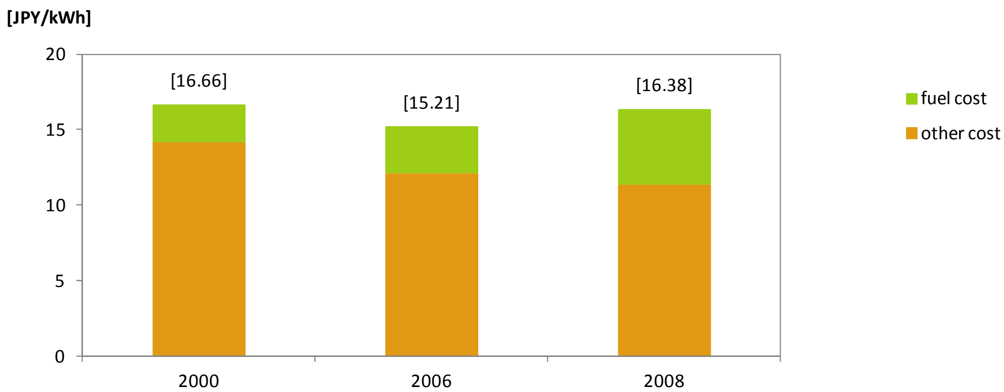
Figure 25 • Generating electricity fuel costs of ten power utilities



Source: Ministry of Economy, Trade and Industry, Japan, 2012.

Since 2000, the consumer price index in the electricity sector had been on a downward trend (until the Fukushima crisis). There is no differentiation between customer groups.

Figure 26 • Consumer prices of regulated public utilities



Note: based on 10 power utilities' regulatory filings.

Source: Statistics Bureau, Ministry of Internal Affairs and Communications, Japan, 2013.

China

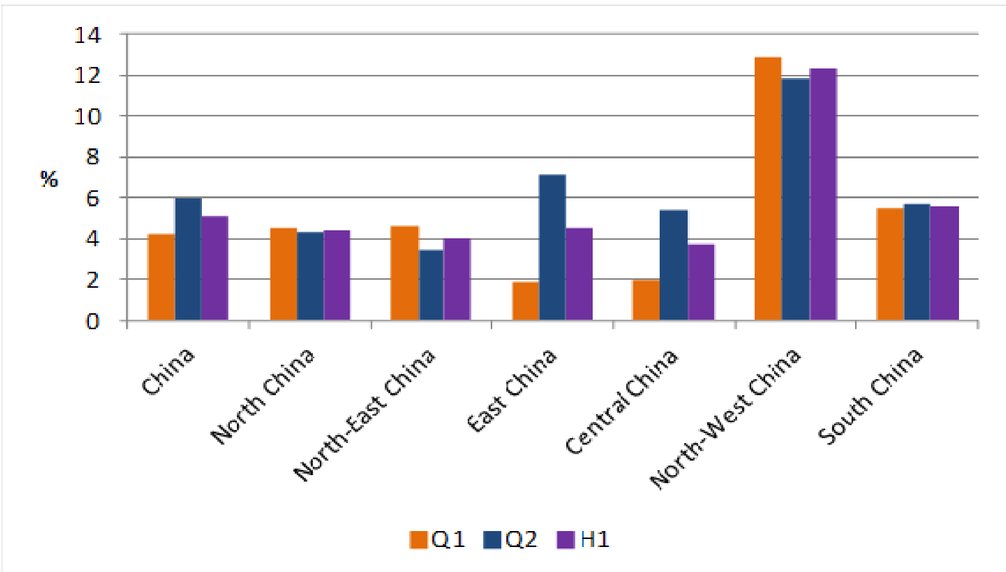
Structure of the electricity market

In March 2002, China's State Council officially approved the "Plan for Electricity Industry Reform", which led to the establishment of eleven large corporations, including two grid companies, five power producers and four auxiliary companies. All the power generation assets of the former State Electric Power Company were restructured and re-organised to be divided into five national independent power producers (IPPs) with equally sizeable capacities, i.e. China Huaneng Group, China Datang Corporation, China Huadian Corporation, China Guodian (Group) Corporation and China Power Investment Corporation. The grid segment of the State Electric Power Company was divided into the State Grid Corporation of China (SGCC) and China Southern Power Grid. State Grid manages five regional grid companies covering China's north, northeast, east, central and northwestern areas. Besides the big five, which together hold round about 50% of overall generation capacity, there are a number of smaller regional generating utilities, plus local state-owned generators.

In September 2011 the four auxiliary companies went through further re-organisation to become two power construction conglomerates; The Power Construction Corporation of China was incorporated based on Sinohydro and Hydrochina, while the China Energy Engineering Group was established with the combined assets of the China Gezhouba Group Corporation and the China Power Engineering Consulting Group Corporation.

China consumed 2.5 trillion kWh of power during the first half of 2013, up by 5.1% on a year-on-year basis. The growth rate, however, declined slightly by 0.4%. In particular, electricity consumption of the secondary industry rose by 4.9% year-on-year. Industrial and manufacturing consumption both grew by 4.8%. Electricity consumption of the tertiary industry grew by 9.3% year-on-year, indicating a still brisk power demand in the market. A rising tertiary industry is also set to bolster growth of both the economy and power consumption in China. In the first half of 2013, urban household consumption rose by 3.9% year-on-year, a relatively slow growth seen in recent years (Figure 27).

Figure 27 • Electricity consumption growth in various parts of China in the first half of 2013



Source: IEA, 2013.

In the first half of 2013, electricity consumption in east, central, west and northeast of China increased by 4.0%, 3.2%, 9.3% and 4.0%, respectively. Power demand is expected to increase during this decade. According to the International Monetary Fund (IMF), China is expected to grow at 8.4% per year between 2013 and 2018. Even though China's economic structure is expected to change towards a less industrial and more service-oriented economy, economic growth and power demand are linked. Therefore, power demand will increase substantially until 2020.

According to the National Bureau of Statistics of China, by the end of June 2013, output from large power plants amounted to 2.43 trillion kWh, up by 4.4% year-on-year. The average utilisation time of generation units reached 2173 hours for the first six months of 2013, down by 64 hours year-on-year. In particular, generation from coal-fired units increased by 2.6% year-on-year, with 2412 utilisation hours during the first six months of 2013. Therefore, coal currently has a share of more than 80% of total generation in China. Even though China aims at diversifying primary energy sources in power production, coal generation is expected to further increase during this decade.

Market design

In the Chinese electricity value chain, limited competition has only been established in power generation, whereas transmission, distribution, and retail are strictly regulated by the government. End-users buy electricity from one of the two state-owned grid companies, which each hold a regional monopoly over both transmission and distribution. The retail tariff is regulated by the state government. The setting of the price is not trivial, as, on the one hand, it has to be sufficiently high in order to encourage investment in the different value stages such as power plants or the grid, while on the other hand, setting a too high tariff would lack public acceptance and could foster inflation. This is one reason why electricity prices for private households are extremely subsidised. Tariffs for industrial consumers are higher than for private households.

The grid companies buy electricity from the generators. The price at which generators sell electricity is also strictly regulated. The so-called "on-grid electricity tariff" has traditionally been one of the most sensitive drivers for power producers, grid-companies, end-users and investors. Power generators at least have to earn their variable costs in order to make them produce. In the long run, their investment has to amortise. Therefore, a too low on-grid electricity tariff might hamper investment in new capacities.

There is not one single on-grid electricity tariff which is valid for all power producers all across the country. The tariff is differentiated by generation technology; wind generation and nuclear generation, for example, receive a higher tariff than coal-fired power plants. Additionally, the different on-grid electricity tariffs vary among regions and provinces. Tariffs in East and South China are traditionally higher than in the central or western provinces. One reason for that is the higher social and economic progress of the coastal and southern regions. Another reason at least for coal power plants might be the higher fuel costs which power plant operators in South and East China have to bear compared to those plants operating in the coal-rich north.

Besides pricing formation in the Chinese electricity market, the dispatch of generating units is another important issue: as discussed for the case of Europe, the merit-order principle determines the dispatch. Conversely, in China, the electricity dispatch is traditionally based on local governments' annual plans, which assign a certain number of generating hours to each plant. In times of lower-than-foreseen demand, all thermal power plants, regardless of their fuel efficiency or costs, are advised to reduce generation. Since this dispatch mechanism usually does not yield an efficient plant dispatch, in 2008 in five provinces, the Chinese government issued trial rules to establish a more efficient dispatch mechanism. Although this dispatch mechanism achieved substantial energy and therefore cost savings, it is seen as critical to implement it on a nationwide level: power plants, which under the new dispatch system were less used than before, *de facto* suffered from declining earnings, such that their asset value decreased (IEA, 2012a).

Fuel supply

With its abundant coal reserves, China is by far the world's largest coal producer, with an annual production of more than 3 500 Mt in 2012. Chinese coal consumption is even higher, making China a net importer of coal. In 2012, imports amounted to more than 300 Mt. About half of Chinese coal consumption comes from the power sector.

However, coal supply and consumption are not distributed evenly across China. The major part of Chinese coal consumption and also coal power generation is located in South and East China, whereas most of the production comes from the northern and western provinces. Therefore, coal transportation plays an important role. Most of the coal transport is carried out by rail. However, coal transport by ship from north to south along the Chinese coast is becoming more and more relevant and made up roughly 600 Mt in 2012 (Figure 28).

Figure 28 • Coal exporting and importing regions in China, 2010

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA, 2012.

Depending on the location of a coal-powered plant, the fuel supply and therefore the fuel costs can vary strongly among different provinces in China. In the coal-rich northern regions, many coal-powered plants are supplied mine mouth (*i.e.* the coal is mined in close proximity to the plant). Others purchase coal from regional domestic markets at rather lower coal prices. In the coastal and southern regions, fuel supply, and therefore fuel prices, are more often related to international markets. Arbitrage between imported coal and domestic coal transported through the country can often be observed.

Developments in coal and electricity prices

Coal and electricity prices in China are basically disconnected from each other due to the different pricing mechanisms mentioned before. Whereas coal markets are liberalised and prices are mainly driven by supply and demand fundamentals, electricity tariffs are strictly regulated by the government. Operators of coal-fired power plants therefore face the problem that, particularly in times of high coal prices, their fuel costs will not necessarily be recovered.

The domestic Chinese coal market was widely liberalised in 2012 when the National Development and Reform Commission (NDRC) announced that it would stop setting prices for coal contracts between power plants and coal mines. Before, the NDRC set coal prices in contracts below spot prices to keep the margins of coal power plants and to reduce pressure on power prices. As a consequence, in times of high spot market prices, coal mines usually stopped selling coal at the lower contract prices. Thus, power generators had to purchase coal on the spot markets.

Buying coal on spot markets, where prices are driven by (also international) supply and demand, and selling power at regulated prices, have two economic implications. In the short run, plant operators have no incentive to purchase coal and run the plant if costs for coal exceed the revenues from electricity sales. In particular, during times of high coal prices, as seen in 2011, this creates the risk of severe power supply disruptions. In the long run, private investors into new generating capacity need market conditions which allow a reasonable return on investment. If coal prices are too high compared to electricity on-grid tariffs, the return on investment might be too low for many investors, such that a capacity shortage might occur in the future.

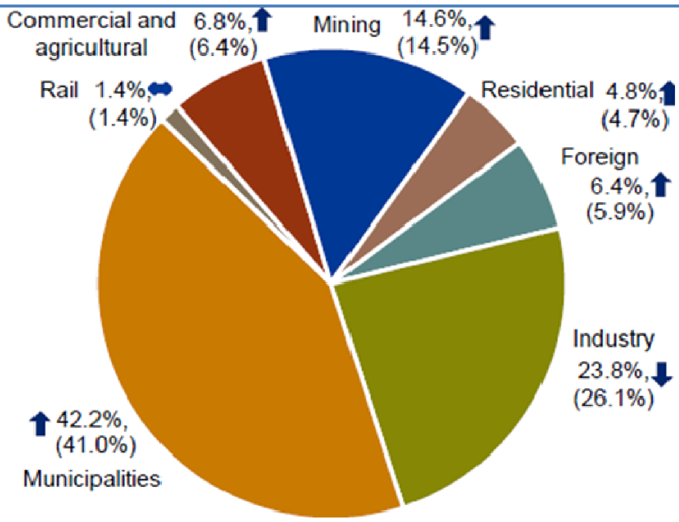
To cope with these problems, the NDRC has installed mechanisms to adapt power tariffs to changing fuel costs. Current regulation – which was introduced in December 2012 but has so far not been applied once – contains a cost pass-through mechanism: the on-grid tariff for coal generators is to be adapted if fuel costs change by more than 5% per year and 90% of the fuel cost changes will be passed through on the on-grid tariffs, leaving the remainder 10% for the plant operators. Although this might ease some problems for the power generators in the future, it has to be noted that similar mechanisms have existed, but have not been applied once. Even if this cost pass-through mechanism were applied, it would basically be a redistribution of the coal price risk from the generators to the grid companies: the grid companies would have to pay higher on-grid tariffs if the coal price rises, but would not be able to pass-through these costs to the customer, since retail prices continue to be regulated by the state. Establishing electricity pricing which leads to reasonable low prices but is profitable for both power plants operators and grid companies therefore remains a core challenge of the Chinese electricity market.

South Africa

Structure of the electricity market and energy mix in power generation

Eskom is South Africa's 100% state-owned, vertically-integrated electricity utility. It supplies approximately 95% of South Africa's electricity from a net maximum generating capacity of 41.9 GW and a transmission and distribution network of 373 280 kilometres (km) (Eskom, 2013). The remaining 5% of electricity supply is made up by a small group of municipal and industrial representatives, predominantly for their own use. In 2012, approximately 42% of Eskom's sales were to (re)distributors in the form of the municipalities which also fund and maintain distribution networks in their respective geographical areas. Municipal customers in turn include industrial, commercial and residential users. A graphic depicting Eskom's sales mix for the financial year ended 31 March 2013 is included below.

Figure 29 • Eskom's electricity sales by customer, 2012



Note: Year end, March 2013

Source: Eskom, 2013.

From the graphic above, it can be seen that Eskom also supplies electricity to neighbouring countries in Africa through its membership in the Southern African Power Pool (SAPP). This is discussed later.

The largest proportion of Eskom's base load comes from coal-fired power stations. Eskom has a net maximum generating capacity of approximately 41 900 MW, comprised as follows:

Table 7 • Eskom's generation capacity by fuel type as at 31 March 2013

Coal-fired stations	35650 MW	85.1%
Nuclear energy	1830 MW	4.4%
Hydropower (including pumped storage)	2000 MW	4.8%
Gas	2409 MW	5.8%
Wind	3 MW	---

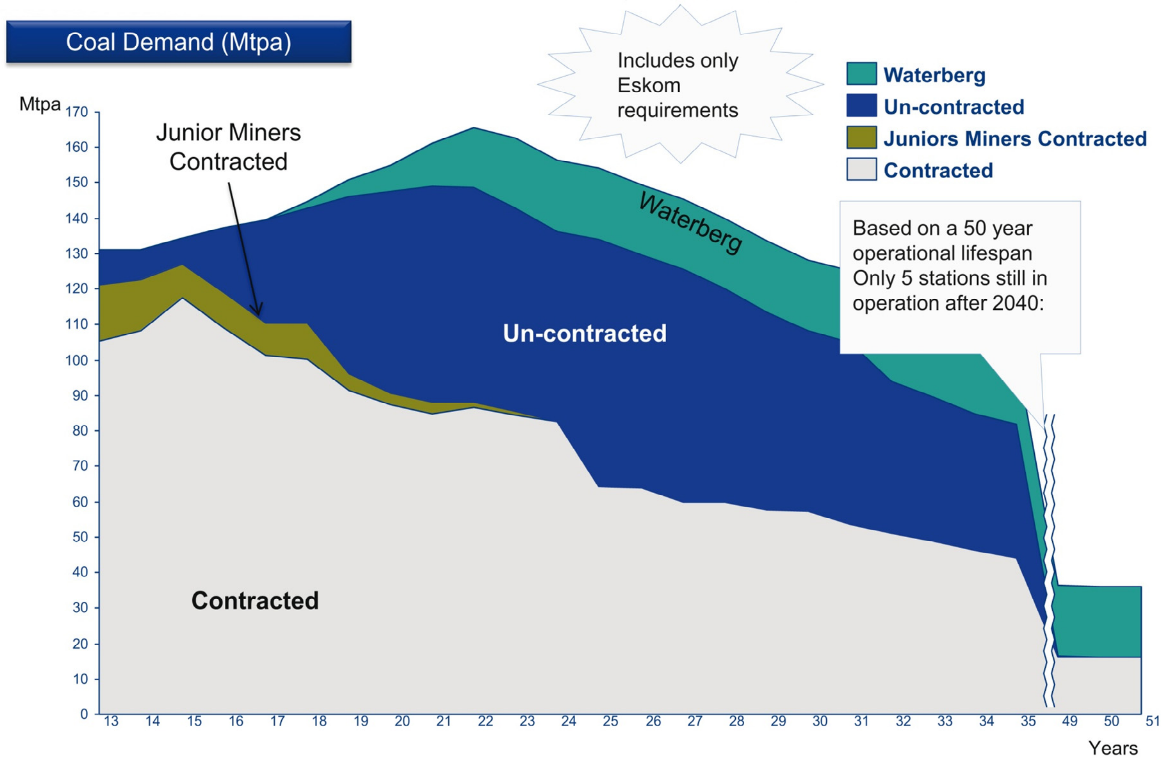
Source: Eskom, 2013.

From the 1970s, Eskom embarked on a strategy to leverage economies of scale through the construction of large, "six-pack" power stations, each with a capacity of 3600 MW or larger. These power stations were built adjacent to the coalfields in order to minimise coal transport costs. Many of the adjacent coal mines supply coal to Eskom by conveyor on a long-term, cost-plus basis. This fleet of power stations is aging and many of the power stations are nearing retirement age.

A period of very low economic growth (and thus power demand) at the end of the 1980's and early 1990s resulted in a delay in the introduction of new electricity supply capacity. This was followed by a more recent, high economic growth in the late 1990's and early 2000's. The lack of investment in new supply capacity over this time has narrowed the electricity supply reserve margin.

Additional coal supplies will be required for power stations running at higher load factors or longer lifetimes beyond what was originally planned for. In addition, Eskom has two new large coal-fired power stations under construction (approximately 4800 MW each) due to be commissioned between 2013 and 2019. The figure below shows the projected coal requirements for Eskom to 2030.

Figure 30 • Projected coal demand



Source: Eskom, 2012.

With existing mines being depleted, approximately 60 million additional tonnes are required in the next five the seven years.

In 2003, the South African Cabinet made a policy decision to introduce independent power producers into the electricity supply industry, such that future electricity generation capacity would be divided between Eskom (70%) and the IPPs (30%). In 2007, the Cabinet designated Eskom as the single buyer of power from the IPPs in South Africa.

In 2011, the Department of Energy published the current iteration of the Integrated Resource Plan (IRP) for South Africa (IRP2010). This plan specifies the new generation capacity requirement for South Africa for the period 2010 to 2030. The IRP is expected to be updated on a regular basis. The figure below shows the IRP2010's proposed new build to 2030.

The need to accelerate development in Africa is widely recognised and access to clean, reliable energy is vital to that task. Excluding South Africa and Egypt, it is estimated that no more than 20%. and in some countries, as little as 5% of the population has direct access to electricity (Eskom 2010). To deal with the challenge of financing new generation capacity, some countries have sought to increase the level of generating capacity to work towards the integration of national power grids and to create cross-border power pools.

The Southern African Power Pool (SAPP) is the first formal international power pool in Africa. It was created with the primary aim of providing reliable and economical electricity supply to the consumers of each of the SAPP members, consistent with the reasonable utilisation of natural resources and the effect on the environment. The current countries/utilities that are SAPP members include Mozambique (Electricidade de Moçambique, HCB, Motraco), Botswana (Botswana Power Co-operation), Malawi (Electricity Supply Commission of Malawi), Angola (Empresa National de Electricidade), South Africa (Eskom); Lesotho (Lesotho Electricity Corporation); Namibia (Nam Power), Democratic Republic of the Congo (Société National d'Électricité), Swaziland (Swaziland Electricity Board), Tanzania (Tanzania Electric Supply Company), Zambia (Zambia Electricity Supply Corporation) and Zimbabwe (Zimbabwe Electricity Supply Authority).

SAPP has made it possible for members to delay capital expenditure on new plants due to the existence of interconnections and a power pool in the region. This is an important aspect in developing the economies of southern Africa.

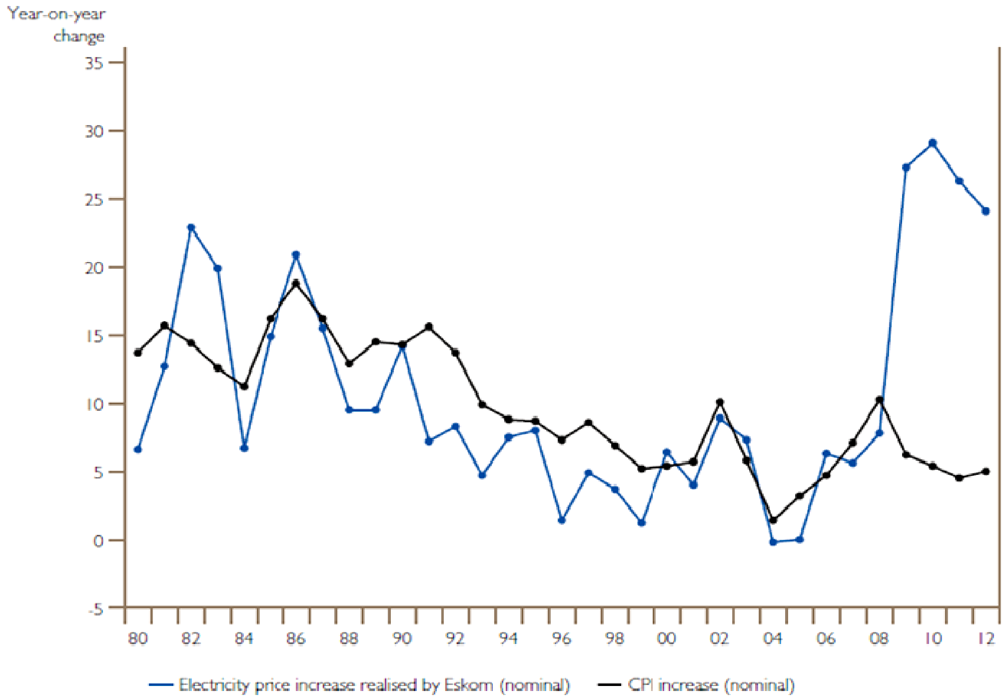
While Eskom (and hence South Africa) is currently a net exporter of electricity, net international sales (sales less purchases) represented only 2.8% of Eskom's total sales in 2013. The majority of the imports are from Cahora Bassa (HCB) in central Mozambique, with small volumes from Lesotho. Eskom exports firm power to the national utilities of Botswana (BPC), Namibia (NamPower), Swaziland (SEC) and Lesotho (LEC).

Market design

Historically, the National Electricity Regulator (NER) was the regulatory authority that presided over the electricity supply industry (ESI) in South Africa. The National Energy Regulator of South Africa (Nersa) replaced the NER in terms of the National Energy Regulatory Act 40 of 2004. Under the Electricity Regulation Act 4 of 2006, it is required to issue licences to all players involved in the production and supply of electricity and to "regulate prices and tariffs" that are supplied by electricity licensees.

For much of the past three decades, electricity prices in South Africa have been low and declining in real terms, as can be seen in the figure below, where electricity price increases did not keep up with inflation. However, from 2008 the trend in prices took a dramatic turn. This increase in electricity prices is the outcome of a policy to charge cost-reflective tariffs.

Figure 31 • Comparison of increase in electricity prices and Consumer Price Index inflation (1980 to 2011)



Source: Eskom, 2012.

The move towards cost-reflective prices in the electricity sector started with Eskom's first price application to Nersa, including the following components:

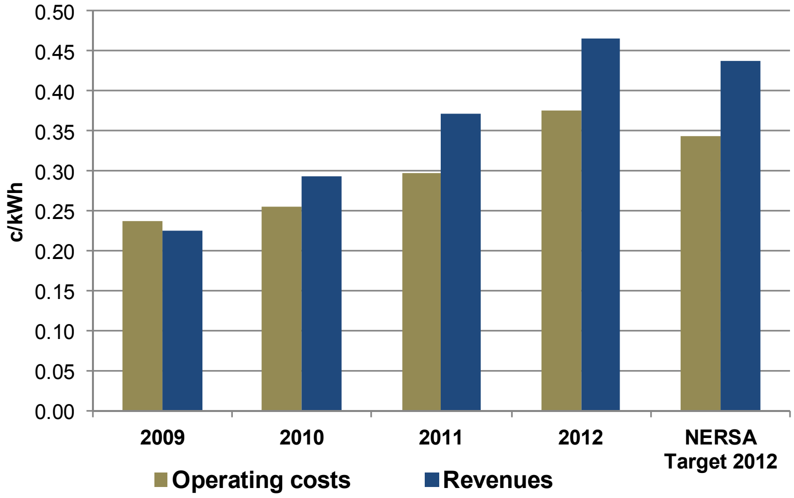
- primary energy, including costs relating to IPPs;
- operating costs, including integrated demand management programmes;
- depreciation, based on Eskom's recently valued replacement asset base; and
- return on assets.

In regulatory terms, a price that fully addresses all of the above components would be "cost-reflective". Demonstrating that Eskom is on a sound financial footing is a necessary pre-condition to raising the investment required to fund the building of new electrical supply capacity projects. Between 2008 and 2011, real electricity prices rose by 78%. However, despite the significant increases, electricity prices in South Africa are still low by international standards and do not yet reflect the full economic cost of supplying power (Deloitte, 2012).

Eskom continues to apply for multi-year price determinations (MYPD) from Nersa. After extensive stakeholder engagement, Nersa then makes a decision on what revenue will be permitted per year for the period requested. As a result of Nersa's previous two multi-year price determinations, electricity revenues have exceeded operating costs.

Effectively, a determination is made on the average price increase, which is then translated into a range of tariffs which are differentiated according to customer class. It is important to note that individual customers may not experience this average price increase; some customers experience higher increases and other customers experience lower increases (including subsidies, where government has identified a social imperative). Redistributors also incorporate their own network costs and revenue requirements to decide on their final electricity prices.

Figure 32 • Eskom's electricity revenues and operating costs



Notes: Excluding depreciation, in c/kWh.

Source: Eskom, 2012.

Since Eskom has a monopoly on electricity production in South Africa, the average electricity price is determined by Nersa through the process outlined above. On the production side, Eskom does minimise costs through dispatching plant according to lowest variable costs, a significant portion of which is attributable to fuel inputs. Currently, the low electricity supply reserve margin necessitates that all plant run whenever possible and cost-order dispatch is not currently possible. This situation is expected to persist until sufficient new capacity is brought online.

Although there is currently no explicit carbon price in South Africa, carbon constraints were factored into the most recently promulgated national electricity supply plan (IRP2010) and the electricity price also carries an environmental levy of ZAR 3.5c/kWh. More explicit carbon pricing has been proposed in the form of a carbon tax. To date, the information provided concerning the proposed carbon tax (National Treasury, 2013) is that:

- a carbon tax will be implemented in January 2015;
- the first phase of implementation will be 2015 to 2020;
- the basic tax-free threshold on emissions remains at 60% during this first phase;
- the 60% may be reduced or removed in the second phase;
- certain industries may be allowed to increase this threshold by up to 10% for trade-exposure and 10% for process emissions, plus 5% to 10% for offsets (but how these offsets will be assessed is still to be defined);
- the tax value is set at ZAR 120 per ton of CO_2e and will increase by 10% annually during the first phase; and
- Scope 2 (including electricity) emissions will be taxed.

Considering the regulatory rules governing tariff increases in the electricity sector, any environmental tax is likely to be passed through to consumers.

The Department of Environmental Affairs is currently developing a carbon budget for the country, in accordance with the National Climate Change Response Strategy White Paper (South Africa Department of Environmental Affairs, 2011) and this would be expressed as "desired emissions reduction outcomes" per economic sector. The interface between sectoral carbon budgets and the proposed carbon tax is also being assessed.

Due to the low reserve margin, the coal-fired power stations are fully utilised with an energy availability factor of 81.2% (Eskom, 2012b). The energy availability factor has declined from 85.3% (March 2009) as the unplanned capability loss factor has increased due to the ageing fleet.

Power-plant fuel supply

South African coal-fired power stations are supplied exclusively by the domestic market, either through dedicated, "cost-plus" mines, or with the middlings product from multi-product mines or through short- and medium-term contracts. There is an indirect connection to the world market through the beneficiation choices of multi-product mines, as well as the future investment choices of mining houses. The impact of global coal market prices on short- and medium-term domestic contract prices has been partially limited by the constrained infrastructure to export coal from inland reserves.

National domestic coal prices are, on average, well below international prices. Given the volatility of coal prices, the relation between domestic and international prices has varied greatly through the years. Since 2008, when export coal prices at the port (Richard's Bay Coal Terminal) were on average almost five times higher than the domestic prices at mine gate, the ratio has been closer to three to one more recently. However, these prices are not directly comparable, given the differences in qualities (yield factors and beneficiation costs) and location (transport, handling costs and terminal charges).

South Africa only has 2 409 MW of open-cycle gas turbine electricity generation installed capacity, about 5% of the total. Due to the lack of local availability of natural or liquefied natural gas, these stations are run on liquid fuels. They are only dispatched during peak periods and during extreme emergencies due to the very high operating (fuel) costs.

The cost of coal in 2012 constituted around 27% of Eskom's total operating costs (calculated from Eskom, 2013). The Nersa determination allows Eskom an average nominal coal price increase of approximately 8% per annum between 2014 and 2018. Meeting the Nersa ruling is of concern to Eskom as the unit cost of coal burnt increased by approximately 14% (adjusted for contractual penalties) between the financial years ending March 2012 and March 2013. Price increases reflect both changes in coal sources and the effect of longer transport distances.

However, there is not necessarily a direct correlation between coal and electricity prices. Electricity prices are regulated and in addition to primary energy costs, there are other cost components which vary. Based on certain assumptions on the value of assets, under the IRP2010, it was projected that the cost of electricity should rise to approximately 78c/kWh (2010 ZAR) in order to reflect the full economic cost of electricity supply from the existing fleet (Republic of South Africa, Government, 2011). This compares with an average electricity selling price of around ZAR 45c/kWh in 2010 (Eskom, 2012b). The current discrepancy in prices reflects a smaller depreciation allowance or a lower allowed rate of return, which Nersa has determined in order to minimise potential negative effects of electricity tariff increases on the economy and to South African society.

How have consumer prices for electricity developed since 2000, differentiated according to important customer groups?

In South Africa, different customers pay different prices for electricity. Domestic and street lighting, for example, almost doubles industrial prices. If we compare the evolution of the different consumer groups in the decade starting from 2001, prices in nominal terms have doubled on average, but with different profiles. Domestic and street lighting only increased 45%, partially offsetting higher increases in most of the other groups.

Conclusion

Global electricity markets are in transition. Major drivers across all continents are the ongoing liberalisation movement in order to implement competitiveness and cost efficiency, the extension of renewable energy sources in order to increase sustainability and the need to guarantee sufficient available generation capacities in all markets to implement and maintain security of supply. Although short-term challenges and political measures vary across the different electricity markets in the world, these general targets are internationally valid. This is illustrated within five electricity market studies from Europe, the United States, Australia, Japan and South Africa.

It becomes obvious that the current and future market role of electricity generation from coal supply is impacted by this development in two dimensions:

- the gradual opening of electricity markets, new suppliers and expanding renewables increase the competition on coal generation; and
- in parallel, the typical market position of coal-fired generation capacities as a result of their permanent availability and high flexibility further increases the influence of coal-fired generation cost on electricity prices.

The competitive position of coal-fired power plants and their technical flexibility are used by the markets to compensate for short-term changes in power demand, *i.e*. in times of rising electricity consumption additional coal plants are requested by the market to be ramped up and in times of declining consumption some coal capacities are temporarily to be disconnected from the grid. Therefore the dispatch behavior of coal-fired plants is transferred into power prices on the wholesale markets. In order to incentivise some plants to connect and disconnect from the grid, electricity prices still need to follow their specific generation cost. As a consequence the price impact of the generation cost of coal-fired plants is significantly higher than their market share. In some European markets it could be observed that the price impact of coal further increased, although the market share was partly substituted by renewables.

Globally coal-fired power generation covered more than 40% of global electricity demand in 2012. According to the analysed market impact of coal-fired generation capacities the influence of coal generation cost on the world electricity prices is even higher than the world market share. Based on the current outlook for the world energy markets, a remaining cost pass through of more than 50% is likely in the time frame 2013 to 2020.

Hence, temporary scarcities in the coal supply chain and adjacent price shocks for coal are to be avoided to keep wholesale electricity prices on a stable level.

List of acronyms and abbreviations

ABS	Australian Bureau of Statistics
AEMO	Australian Energy Market Operator
ARA	Amsterdam, Rotterdam and Antwerp
BTU	British thermal unit
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CEER	European Agency for the Cooperation of Energy Regulators
CHP	combined heat and power
CIF	cost, insurance and freight
CO_2	carbon dioxide
EEX	European Energy Exchange
EIA	U.S. Energy Intelligence Administration
EPA	U.S. Environmental Protection Agency
EPEX	European Power Exchange
ETS	emission trading system
EU	European Union
FADE	*Fondo de Amortización de la Deuda Eléctrica* or Fund to Pay off the Electricity Debt
FERC	U.S. Federal Energy Regulatory Commission
FOB	free on board
GDP	gross domestic production
GJ	gigajoule
GW	gigawatt
IMF	International Monetary Fund
IPP	independent power producer
IPART	NSW Independent Pricing and Regulatory Tribunal
ISO	independent system operator
JEPX	Japan Electric Power Exchange
km	kilometre
kWh	kilowatt hour
mt	million ton
MYPD	multi-year price determination
NDRC	China National Development and Reform Commission
NEM	national electricity market
NERC	North American Reliability Corporation
Nersa	National Energy Regulator of South Africa
NSPS	new source performance standard
NSW	New South Wales
NUG	non-utility generator
OTC	over the counter
PC	pulverised coal
PV	photo voltaic
QF	qualified facility
RTO	regional transmission organisation
SAPP	Southern African Power Pool
SGCC	State Grid Corporation of China
TWh	terawatt hour
ZAR	South African rand

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