

PROJECT REPORT

The economic viability of hard-coal-fired power plants demonstrated on the example of the planned hard-coal-fired power plant in Mainz

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ABSTRACT

The German utility Kraftwerke Mainz-Wiesbaden AG is planning a hard-coal-fired heat and power plant with a gross electrical output of approximately 820 MW. An investment of circa 1.3 billion euro is slated.

This study shows that the economic viability of this investment is threatened by a variety of factors:

- The many new power plants currently in construction or in planning will lower the price of electricity, since new power plants have lower marginal costs than existing plants. This reduces the revenues of all power plants.
- Developments in 2008 have shown that in the upcoming years – after the financial and economic crisis has been resolved – we can expect sharp increases in the price of fuel. The price of coal may, as in 2008, rise more steeply than the price of gas. As a result, the operating costs of a hard-coal-fired power plant would increase more than its revenue.
- Greater utilization of renewable energy sources to produce electricity will, in the mid- and long term, result in conventional power plants not being used at full capacity. This has a direct impact on revenues. It also requires that conventional plants be able to react flexibly, which is difficult for hard-coal-fired plants to achieve.
- Many renewable energy facilities have no marginal costs at all. The increased use of renewable energy will cut electricity prices during many hours. This is a further factor that reduces hard-coal-fired power plant revenues.
- However the greatest economic threat to hard-coal-fired power plants by far comes from climate policy objectives. Mid- and long-term climate protection goals can only be reached if specific CO₂ emissions from electricity production are reduced from currently 600 g/kWh to 450 g/kWh by 2020 and to at most 150 g/kWh by 2050. This can not be achieved with the investments currently planned; to the contrary, the slotted investments put the achievement of these goals at risk. Therefore, the CO₂ price will continue to rise until plants remain within the emission budget. Building new hard-coal-fired power plants today will in the near future force society to choose between either closing these plants prematurely or abandoning climate protection objectives.

New hard-coal-fired power plants lead to rising CO₂ prices and thus also to higher prices for electricity. Hard-coal-fired power plants therefore do not guarantee consumers affordable electricity prices long-term, but rather add considerable economic risks.

After weighing chances and risks, taking economic considerations and climate policy into account, we advise public investors against building new hard-coal-fired power plants.



1 INTRODUCTION

1.1 The planned power plant in Mainz

The German utility company Kraftwerke Mainz-Wiesbaden AG is planning a hard-coal-fired heat and power plant with a gross electrical output of around 820 MW.

A number of assessments from 2006 and 2007 have found similar power plants to be economically viable (e.g. PWC 2006). In 2008 however, key parameters changed considerably. For example we now know it is most probable that starting 2013, directly following the plant's planned start of operations, all carbon dioxide (CO₂) emission allowances will be auctioned. The fuel prices these assessments were based on must also be reevaluated after the drastic price increases in 2008 and the price collapse that followed in the wake of the financial and economic crisis. Existing assessments also ignore the interconnection between power plant investments and climate protection policy. For example, the construction of hard-coal-fired power plants in particular affects the price of CO₂ and thus also electricity production costs as well as electricity costs. The increased use of renewable energy sources, which shall decrease the operating time of conventional plants in the near future, has also been largely ignored to date.

1.2 Mission and approach

This report shows that investments in hard-coal-fired power plants are a great financial risk, particularly if one assumes that the climate protection objectives Germany and the EU envisage, and have in part ratified, will be implemented.

To illustrate this, we first describe how the electricity market works. We then look at how changes in key parameters affect market prices and power plant revenues. Using model calculations, we then determine whether these revenues are sufficient to compensate for investments in hard-coal-fired power plants. We further analyze how changes in the stock of all power plants affect average specific CO₂ emissions and how this in turn affects the price of carbon dioxide.

1.3 Background: Climate policy

Human-induced greenhouse gas emissions threaten to change the global climate, bringing – according to current scientific understanding – a plethora of negative consequences for the quality of life on Earth.

The Kyoto Protocol, which went into effect in 2005, set the first binding objectives to cap greenhouse gas emissions. Currently, "post-Kyoto" goals for the time period after 2012 are in negotiation. The international community aims to adopt a new protocol at the next climate conference in Copenhagen at the end of 2009.

Table 1 shows the changes that must be made on a global scale depending on CO₂ concentration levels as well as reductions that need to be made by the so-called Annex I parties to the Climate Framework Convention, including Germany. Germany and Europe aim to limit global warming to a rise of 2 degrees Celsius (EU Council 1996, CEC 2008, BMU 2007). To do so, the industrialized countries must reduce their emissions by 80% to 90% by the middle



of the century. Newest scientific discoveries meanwhile suggest that this needs to be adjusted to reductions as high as 95% (Meinshausen et al. 2009). In the following, a conservative estimate in favor of hard-coal-fired power plants has been made of a "mere" 80% reduction of greenhouse gas emissions.

Mid-term objectives of 25 to 40 percent reductions by 2020 can be derived from these long-term objectives for Annex I countries, as Table 1 illustrates.¹ Accordingly, the EU has already set a one-sided goal of a 20% emissions reduction by 2020 with 1990 as base year (CEC 2008). If other countries come on board, the EU would be willing to accept a reduction of 30%. The German federal government aims for a reduction of 30% and is willing to accept a target of 40% if the EU as a whole accepts a 30% reduction (BMU 2007).

Table 1. Greenhouse gas stabilization scenarios (adapted from UNFCCC 2007).

CO ₂ equivalent concentration (parts per million)	Global mean temperature increase (°C)	Change in global CO ₂ emissions in 2050 (% of 2000 emissions)	Emission reduction goal for Annex I countries in 2050 (% of 1990 emissions)	Emission reduction goal for Annex I countries in 2020 (% of 1990 emissions)
445 - 490	2.0 - 2.4	- 80% to -50%	-80% to -95%	- 25% to -40%
535 - 590	2.8 - 3.2	-30% to +5%	-40% to -90%	-10% to -30%
590 - 710	3.2 - 4.0	+10 to 60%	-30% to -80%	0 to -25%

Government emission reduction targets can only be reached if they are converted into emission reduction requirements or incentives for specific emitters in individual sectors. The fact that emissions trading has been created to steer investments so that they have the greatest possible effect should not obscure the fact that emission reductions of this magnitude can only be achieved if all sectors make substantial contributions that add up to the necessary reduction. Emissions trading may then determine whether individual sectors make reductions of a couple of percent more or less.

Figure 1 and figure 2 show a reduction scenario for the entire economy and for the electricity industry. In this scenario, the reduction objective of -80% has been distributed fairly among the individual sectors. However this is a conservative analysis as it is still completely unclear how some sectors, such as the manufacturing sector or transportation, will be able to meet this target. It is therefore probable that the electricity production sector will have to reduce its CO₂ emissions even more.

As can be seen in figure 1, the emissions budget for the energy industry (electricity and heat) decreases from currently over 300 mill. t CO₂ to just under 85 mill. t by 2050. Thus the mean specific emission for electricity production would be 150 grams per kilowatt hour (g/kWh) (figure 2).² Today, this value is at almost 600 g/kWh.

¹ Annex I of the Kyoto Protocol lists the countries that have already made binding commitments to cap their greenhouse gas emissions. It is basically a list of the industrialized countries, excluding the USA.

² A more detailed illustration of this derivation can be found in Bode (2009).

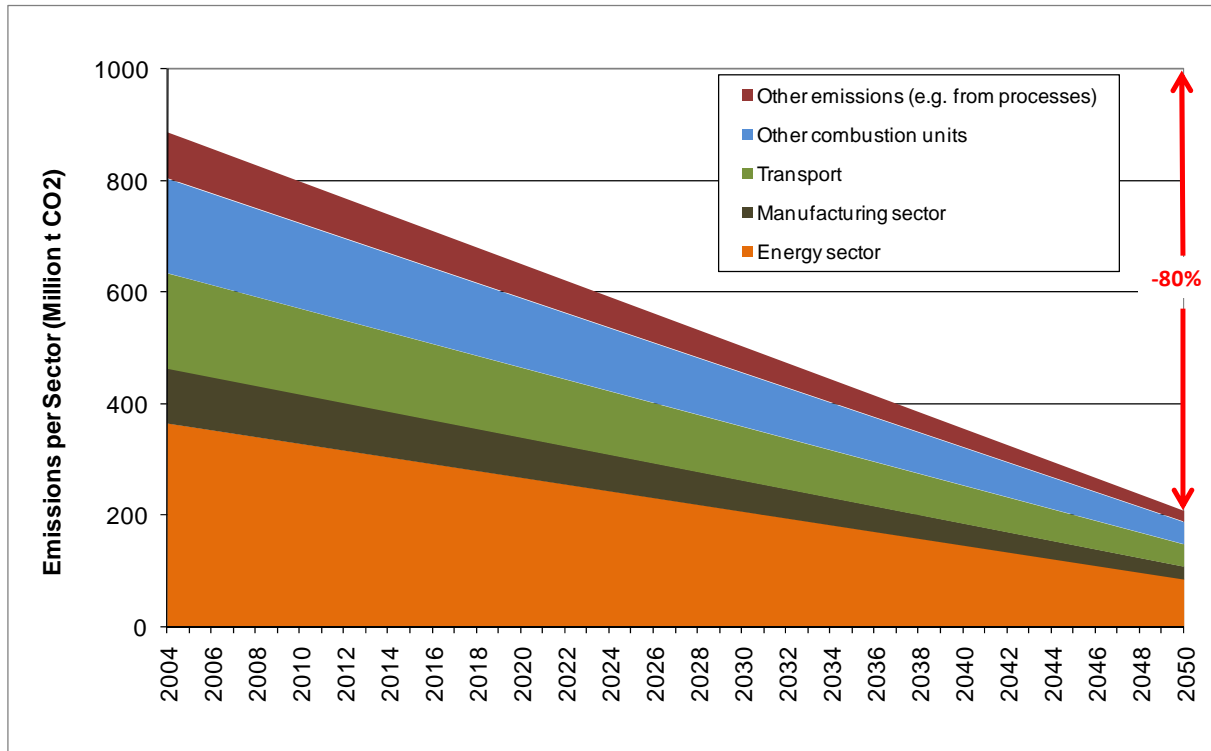


Figure 1. Emission scenario for a CO₂ reduction goal of -80% from 1990 (calculation by author; 1990 emissions: UBA 2006).

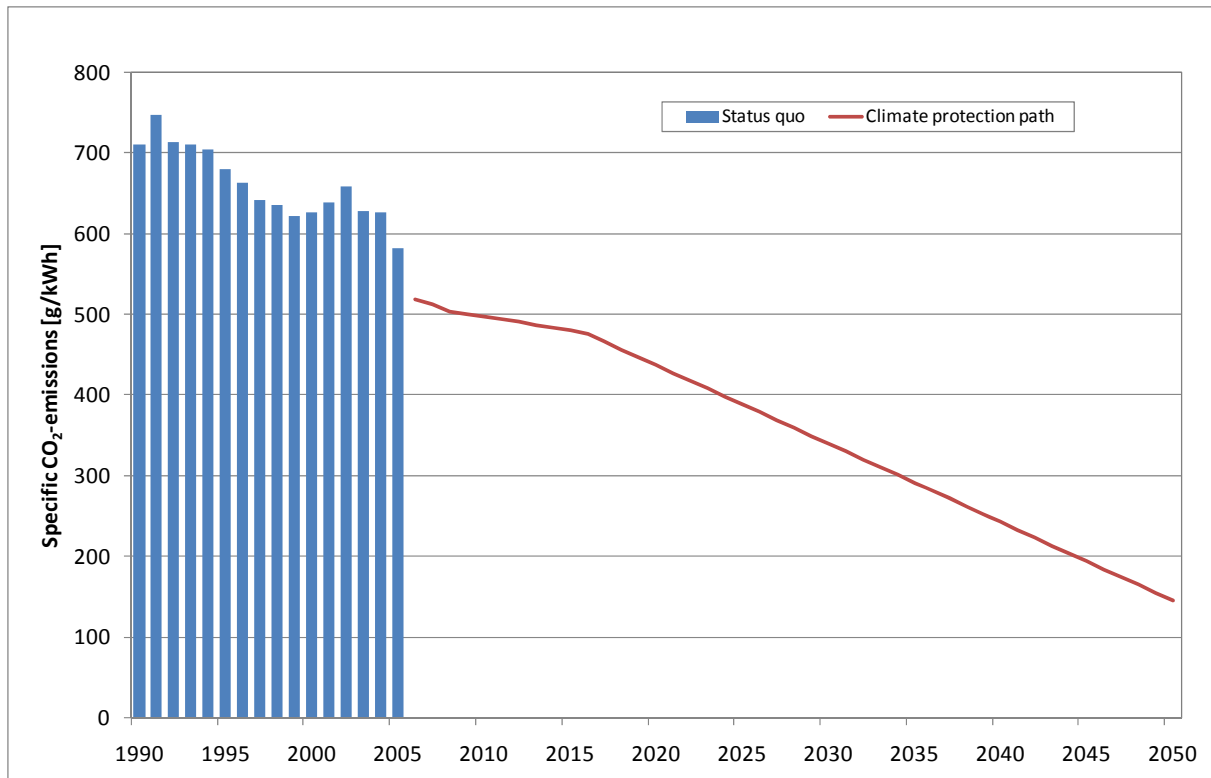


Figure 2. Scenario for the reduction of mean specific CO₂ emissions of all German power plants (calculation by author; status quo: LAK Energiebilanzen).



2 HOW THE ELECTRICITY MARKET WORKS

In this chapter, we explain how the wholesale electricity price is set on the European Energy Exchange (the German energy market - see also Groscurth and Bode 2009). First however we must delineate the costs incurred in the production of electricity and those parts of production costs that are relevant to the creation of prices.

2.1 Electricity production costs

A power plant's electricity production costs are made up of a variable portion that is (usually) proportional to the amount of electricity produced and a fixed portion that is incurred whether or not the plant produces electricity. To facilitate understanding, let us simplify and assume that there are only three cost factors:

- investment or capital costs;
- fuel costs;
- costs for CO₂ emission allowances.

Investment costs are typical fixed costs while the two other types are variable costs. As a rule, other conventional power plant expenses such as fixed and variable operating costs and maintenance costs are low in comparison to the three above-named factors, and shall therefore be disregarded in this basic overview.³ Variable fuel costs and CO₂ costs depend upon fuel prices, the power plant's level of utilization,⁴ the fuel's specific CO₂ emissions and the price of CO₂.

Figure 3 illustrates typical electricity production costs for old and new power plants. Old power plants that are already amortized no longer have capital costs. The capital costs of a new power plant depend greatly upon how many hours per year the plant is in operation. Thus the values given in figure 3 are typical, but may vary depending upon conditions. The calculation is based on a gas price of 20 €/MWh_f, a hard coal price of 8 €/MWh_f and a CO₂ price of 20 €/t (see table 8 in the appendix).⁵

The hard-coal-fired power plant planned in Mainz is similar to the "new coal-fired power plant" in figure 3, the existing natural-gas-fired combined cycle power plant is similar to the "new CCGT power plant."

³ For renewable energy facilities this can look different. Wind farms for example have O&M costs of 15-30 €/MWh. Since this study concentrates on hard-coal-fired power plants, we nevertheless make this assumption to simplify our illustration.

⁴ A power plant's level of utilization is the ratio of the electricity produced and the amount of fuel necessary to produce it. It is also known as the average power efficiency.

⁵ €/MWh_f: The addition of "_f" means that the price refers to the energy content of the fuel. Endings with "_el" refer to the electricity produced.

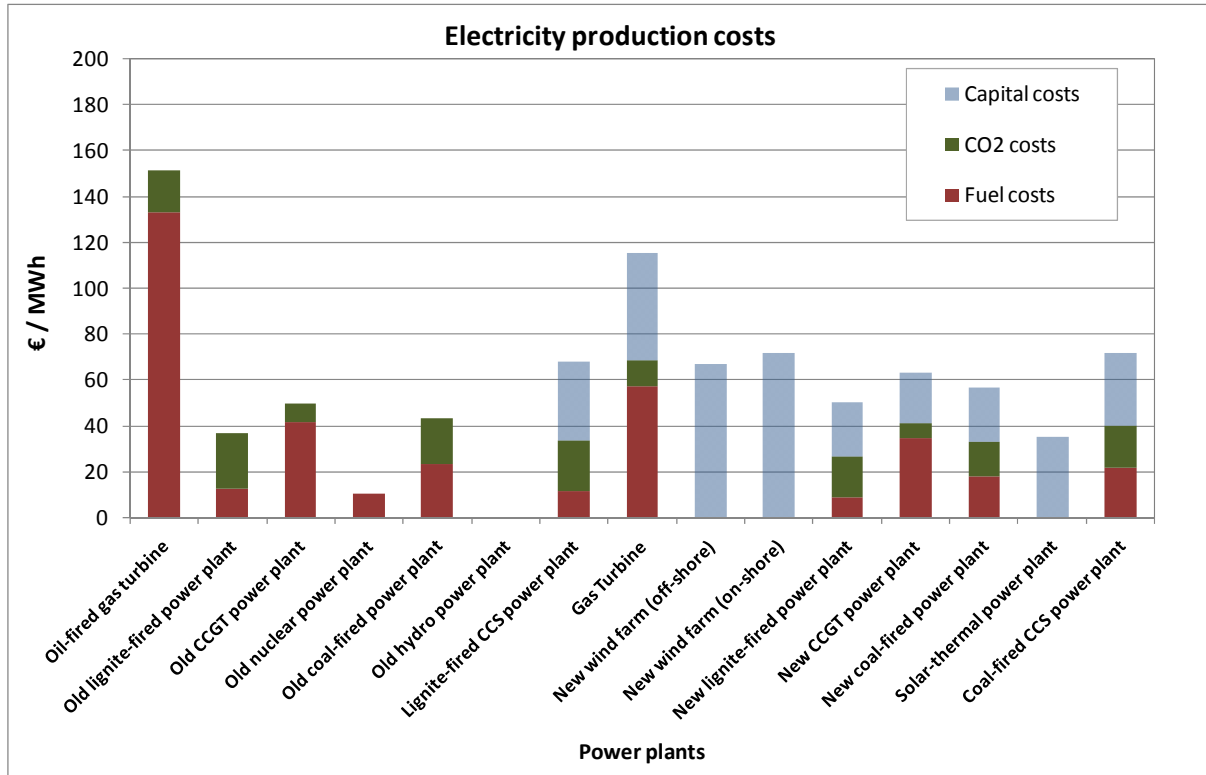


Figure 3. Typical electricity production costs for older and newer power plants (calculation by author; based on data from table 7 in the appendix).⁶

2.2 Determining the price of electricity and power plant revenue

To explain how prices are determined on the market, in the following we examine only the so-called spot market, on which electricity for the next day is traded on an hourly basis (day-ahead market).⁷ This is the closest approximation to what actually happens physically. In this basic model we also assume that the market is completely competitive and no generator has enough market power to influence prices.

Every utilities company can bid on the electricity market for every hour of the next day. The bid is composed of a price and the amount of electricity that can be supplied at that price. What price does a utility set for its electricity? If a power plant has already been built, companies' considerations are different than when making pre-investment analyses. Capital costs are no longer relevant to decisions on the operation of a power plant, because they are fixed costs, due whether or not the plant is in operation.

⁶ The specific fixed costs depend greatly upon a plant's operating time. We have assumed 7.000 hours of annual operating time (h/a) for the hard-coal-fired power plant and 4.000 h/a for the CCGT power plant.

⁷ Alongside the spot market there is also a forward market on which standardized products are traded, i.e. a defined amount of electricity over a set period of time (years, quarters, months). Prices on the forward market are however oriented towards spot market prices.



The owner of an existing power plant will always try to make use of a facility when the revenue from selling the electricity for an hour is higher than the facility's operating costs. At first approximation, this is the case when the marginal costs of production are lower than the price of electricity that can be realized. Marginal costs are made up of the sum of specific fuel costs and specific CO₂ costs.

The market collects all bids and sorts them in ascending order. The result is the ranking of the power plants to be used, the so-called merit order. Figure 4 gives an example of a merit order curve. In this figure, the power plants have been assigned capacities similar to the current capacity of Germany's stock of power plants.⁸ To the left are power plants with little or no marginal costs such as hydroelectric plants, wind farms and photovoltaic systems. Next come nuclear power plants, followed by new and then old lignite- and hard-coal-fired plants. Further to the right are gas-fired power plants which have low investment costs, but high marginal costs. At the very end of the merit order are the peak load power plants, for example simple gas turbine power plants that are oil-fired and have very high marginal costs. The market then awards contracts to the power plants one after another starting with the lowest bid until the expected demand is met.

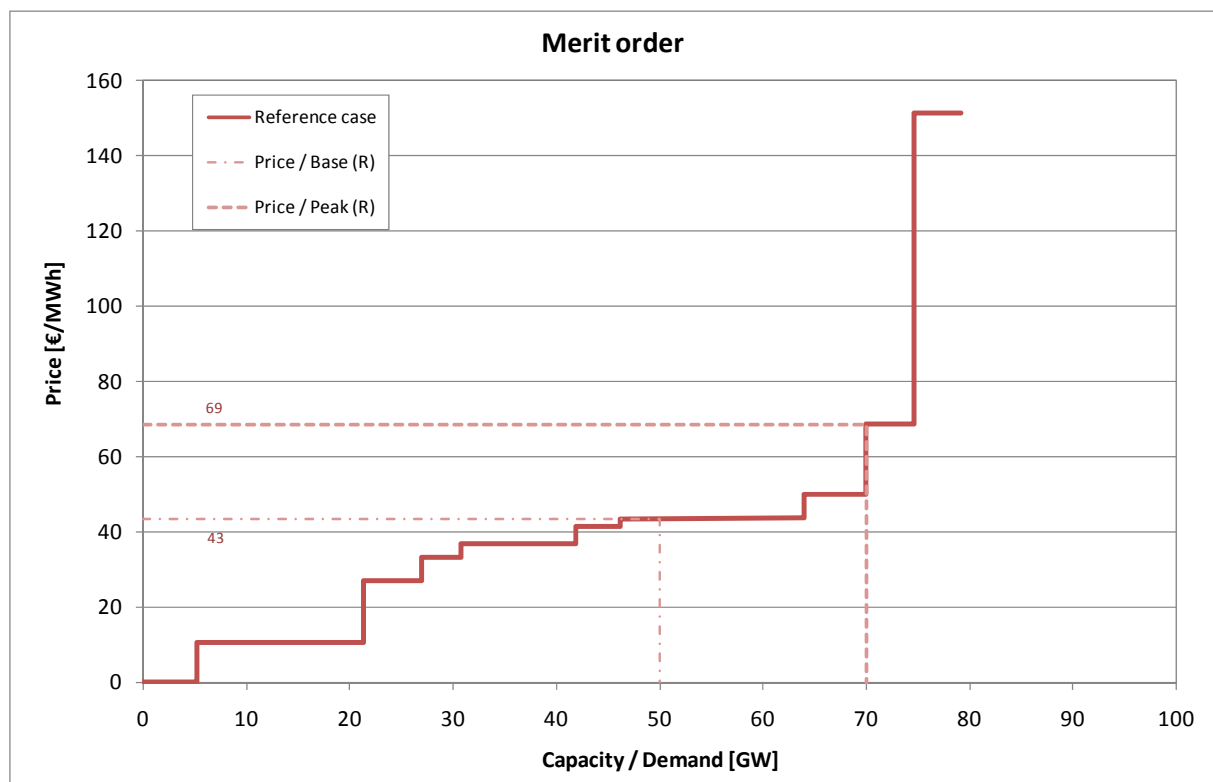


Figure 4. Price setting mechanism on the electricity market at two exemplary high-capacity and low-capacity hours.

Typical merit order curve for a stock of power plants representative of Germany in 2009 on the basis of power plant types with little electricity available from renewable energy sources. The real curve depends upon the conditions of each hour. On the effects of increased electricity from renewable energy sources see chapter 3.2.

⁸ The capacities assumed are listed in table 11 in the appendix. They approximate the current stand of the German stock of power plants.

This is not a particularity of the electricity market but a common mechanism on completely competitive markets.

The last power plant to be awarded a bid (the so-called marginal power plant) determines the electricity price paid to all suppliers. The utilities are not paid the amount they themselves have bid, but rather a spot price determined by the last bidder.

Figure 4 illustrates this mechanism for two exemplary hours. The electricity price is determined by the demand and supply curves' point of intersection. In this example, the demand is inelastic; demand does not sink when the electricity price rises (horizontal line in figure 4). This is a sensible assumption to make when estimating short-term demand, at least for the left and middle section of the merit order curve. Below we shall discuss the case of a reduction in demand due to high prices.

As long as there is enough capacity, the market price for electricity in any hour is equal to the marginal costs of the last power plant needed to meet the demand for electricity in this hour.

In times of low demand of 50 GW, the marginal power plant in figure 4 is a hard-coal-fired power plant and the price is thus 43 €/MWh. When demand rises, the demand curve moves to the right. It then intersects the supply curve at a higher price. At a demand of around 70 GW, the marginal power plant is gas-fired and the price rises to 69 €/MWh.

In reality, the merit order curve is less step-like, but rather ascends mostly continuously. This is because real individual power plants differ from one another and thus also have varying marginal costs. It is however irrelevant to this basic overview whether the electricity price remains constant or varies slightly. More important is the fundamental effect, which can also be illustrated by a simplified model of Germany's stock of power plants.

Recently, negative prices have also occasionally occurred on the market. This happens when the owners of conventional power plants want to avoid the expensive process of shutting down and starting up a facility within only a few hours. They are then willing to pay to be allowed to deliver electricity in the interim hours.

Up to now, we have only looked at one individual hour. However both the merit order curve in figure 4 as well as the demand curve change continuously. To determine the average price of electricity for one year, we therefore need to examine the same parameters for all the hours of a year. To this end, it is necessary to have a detailed knowledge of the fluctuation of demand and supply. Figure 5 shows seasonal and daily fluctuations in load. The following model calculations are based on a distribution function for the (remaining) electricity demand, after electricity from wind power has been deducted from the real demand.

If power plants are not paid according to their own costs, but rather the costs of the marginal power plant, what is done with the difference? Economists call this difference the contribution margin. It covers – among other costs – the power plant's fixed costs which have not yet been calculated into the market bid. In figure 6, the market value of the electricity produced is represented by the area under the dotted rectangle. The supply curve (merit order curve) divides this area into the variable costs (operating costs) below the curve and the contribution margin above it. As figure 6 shows, that marginal power plants usually have no contribution margin.

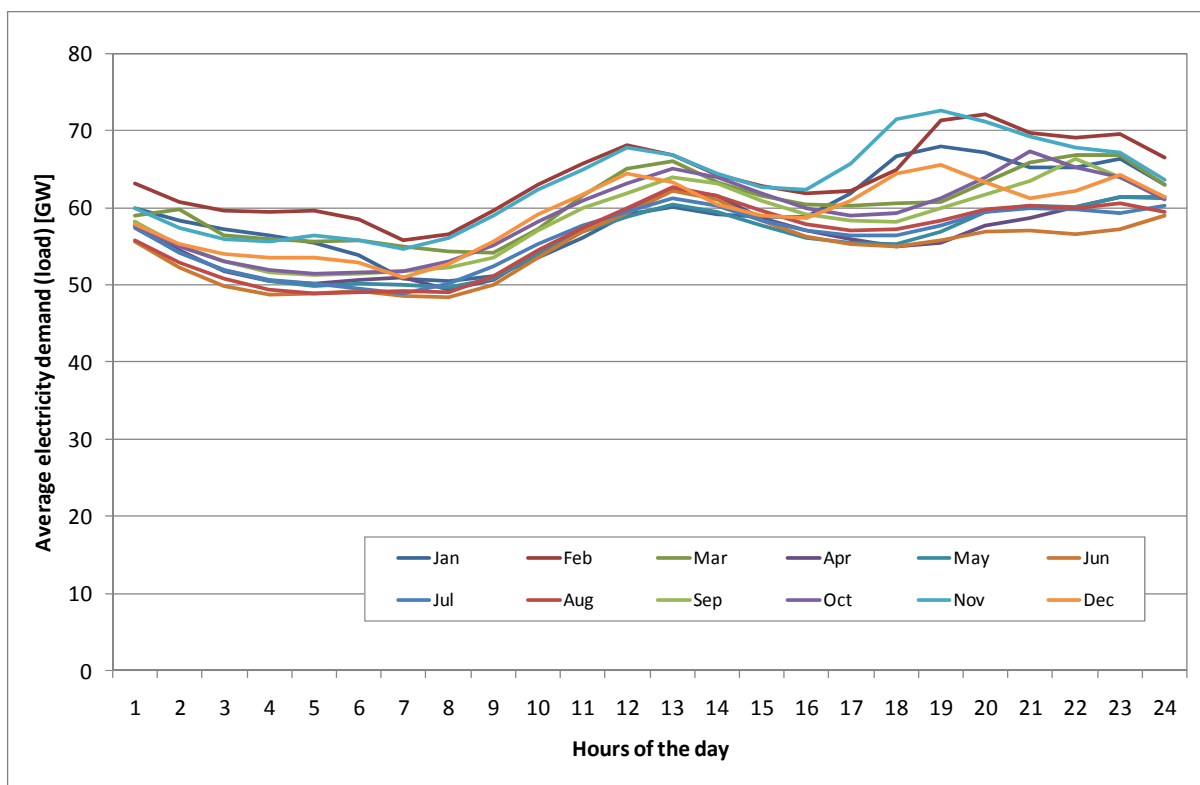


Figure 5. Course of the average monthly demand for electricity (load) in Germany in 2006 (www.ucte.org).

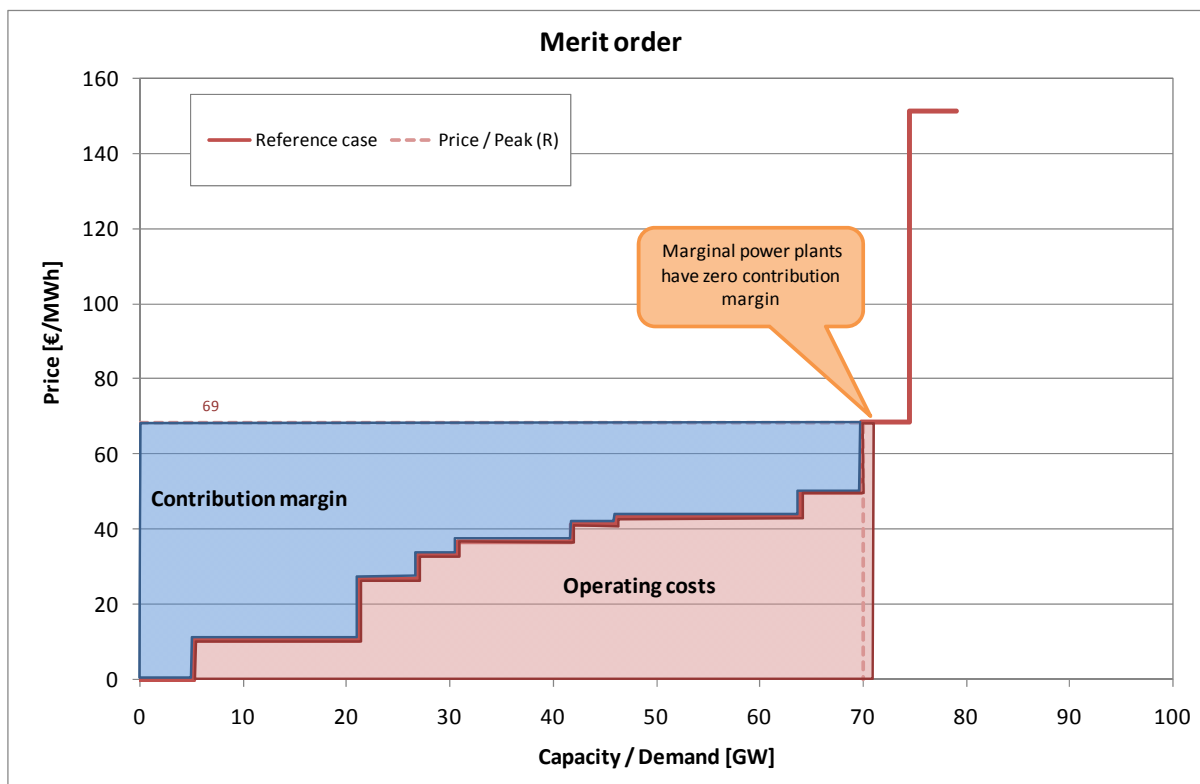


Figure 6. Revenue and contribution margin of power plants on the electricity market.

3 CHANGES IN CRITICAL PARAMETERS

3.1 Fuel prices

The price of electricity is determined by the last power plant in the merit order. This plant's marginal costs are in turn determined by the price of fuel and CO₂ emission allowances. Since in many cases a gas-fired power plant is the last plant in the merit order, it is not sufficient to only study changes in coal prices to assess the economic viability of a hard-coal-fired power plant. Rather, fluctuations in the three most important parameters need to be analyzed: coal prices, gas prices and CO₂ prices.

Figure 7 gives an impression of just how much these three prices have fluctuated in the past three years. In particular it reveals that in the summer of 2008, as clear signals of scarcity were mirrored on the global energy markets, the price of coal increased more sharply than the price of oil or gas. Alongside the prices themselves, figure 7 also shows the difference between coal and gas prices, a decisive factor for the economic viability of power plants.

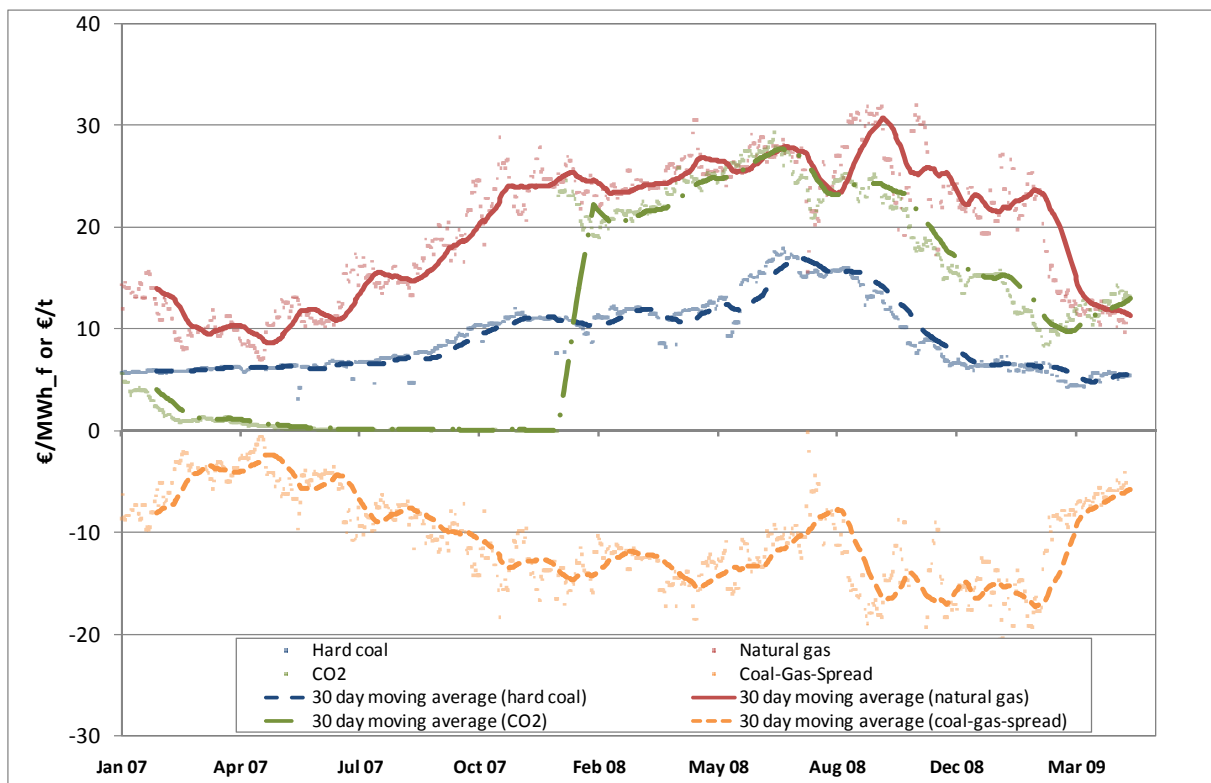


Figure 7. Development of fuel and CO₂ prices since January 2007 (graphic by author).



The following observations are based on today's stock of power plant (see table 11 in the appendix). Changes in the make-up of this stock are discussed further below. At this point, we are not yet making any final assessment of the economic viability of new hard-coal-fired power plants, but rather only attempting to explain market mechanisms.

If just the price of coal rises – and other conditions remain the same – electricity prices will only rise when a hard-coal-fired power plant is at the end of the merit order. Electricity prices remain the same during the remaining hours. However, supplementary costs are accrued during all of the facility's operating hours. Thus it is clear that the total contribution margin decreases. Furthermore, when coal prices rise, new hard-coal-fired power plants move to the right in the merit order and are possibly needed less, lowering the contribution margin even more. To make this effect clear, figure 8 illustrates a 50% rise in the price of coal.

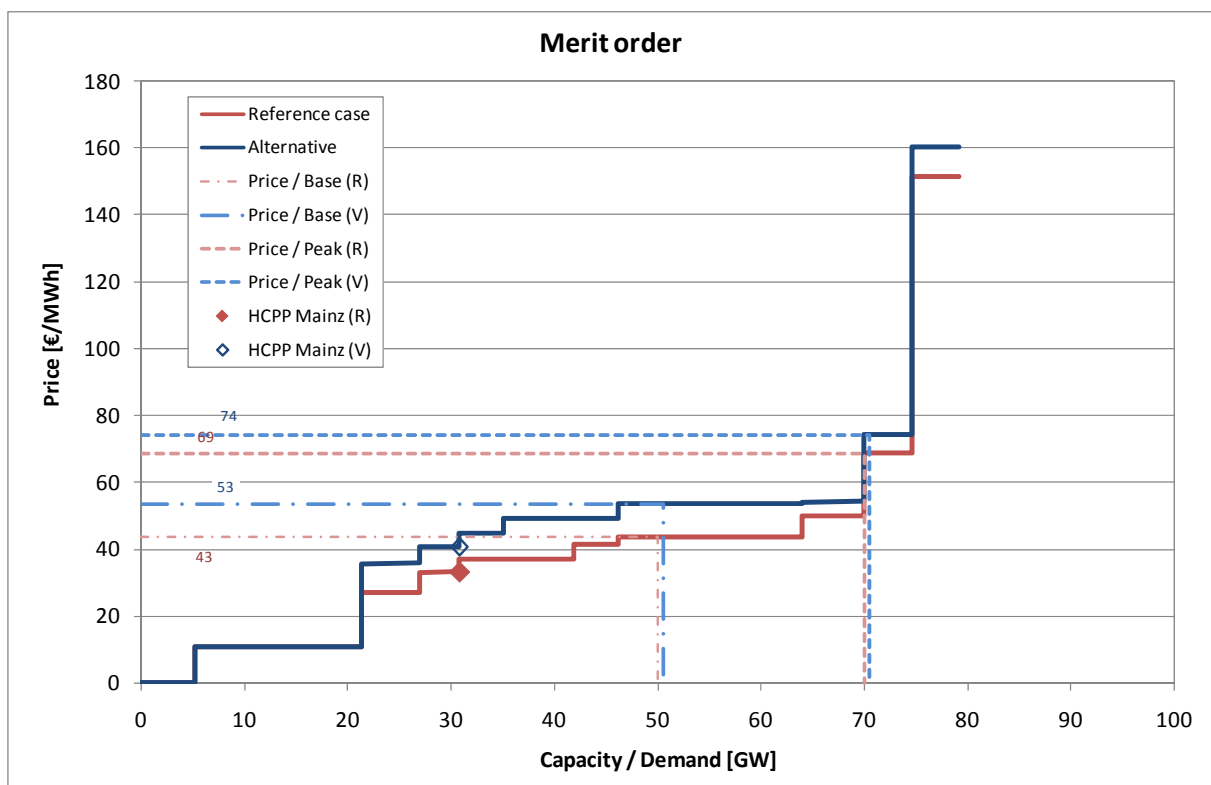


Figure 8. Changes in the merit order curve (stand 2009) for two exemplary demand curves at a 50% coal price increase (V) compared to the reference case (R). The diamonds show the position of a new hard-coal-fired power plant.

A rise in the price of natural gas leads to a rise in the price of electricity at times of high capacity when the marginal power plant is a natural gas-fired power plant. The price of electricity during the remaining hours remains the same. The planned hard-coal-fired power plant profits from this rise in the price of electricity, which is expressed as a higher contribution margin. The merit order does not however change. Figure 9 illustrates the changes in the merit order when the price of natural gas rises by 50%.

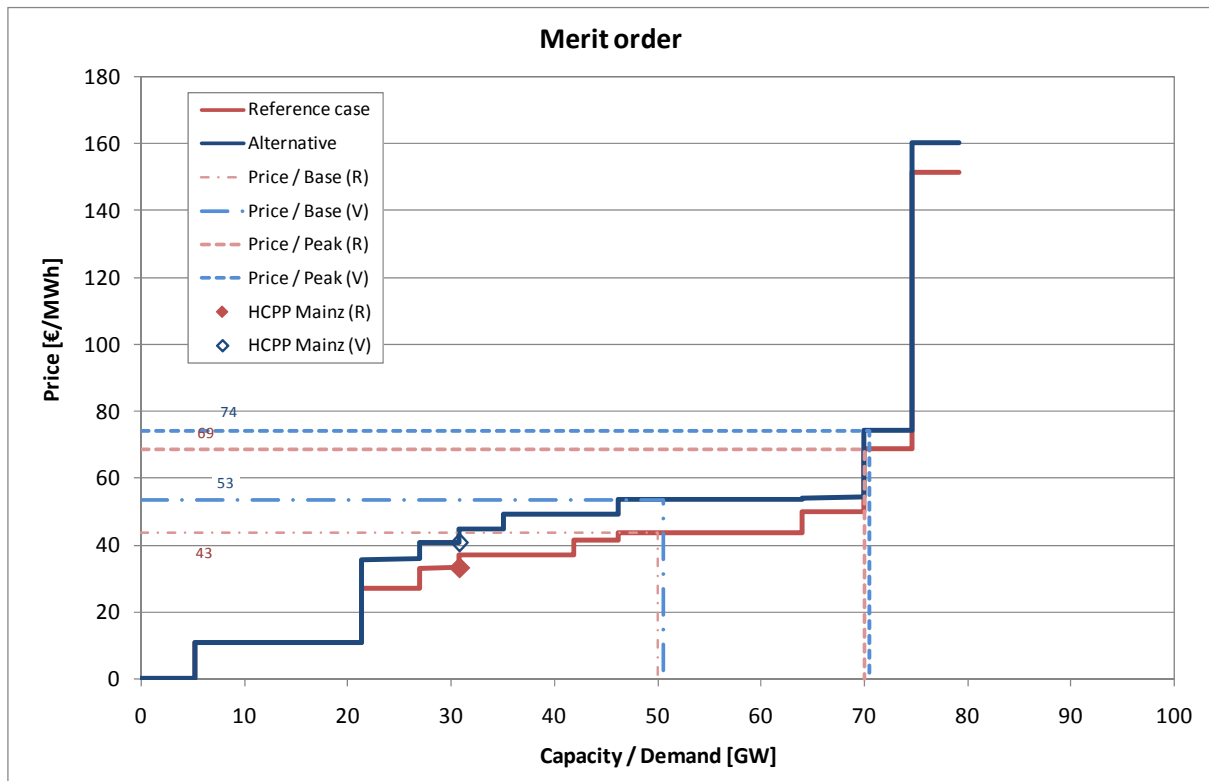


Figure 9. Changes in the merit order curve (2009) for two exemplary demand curves at a 50% increase (V) in the price of natural gas compared to the reference case (R). The diamonds show the position of a new hard-coal-fired power plant.

As a rough approximation – in particular ignoring changes in the price of CO₂ – we can say that hard-coal-fired power plants are economically viable as long as the difference between coal prices and gas prices is higher than 12 €/MWh_f. However figure 7 shows that in the past three years, there was more than one period during which this was not the case.

A 50% rise in the price of CO₂ increases the marginal costs for both hard-coal-fired and gas-fired power plants; but less so for the latter than for the former (see figure 10). Hard-coal-fired power plants profit from rising electricity prices at times when a gas-fired power plant is the marginal power plant. This is not true the other way round as gas-fired power plants are not in use when a hard-coal-fired plant is the last plant in the merit order.

Not until the price of CO₂ is more than 40 €/t is a new natural-gas-fired combined cycle power plant in front of a new hard-coal-fired power plant in the merit order.

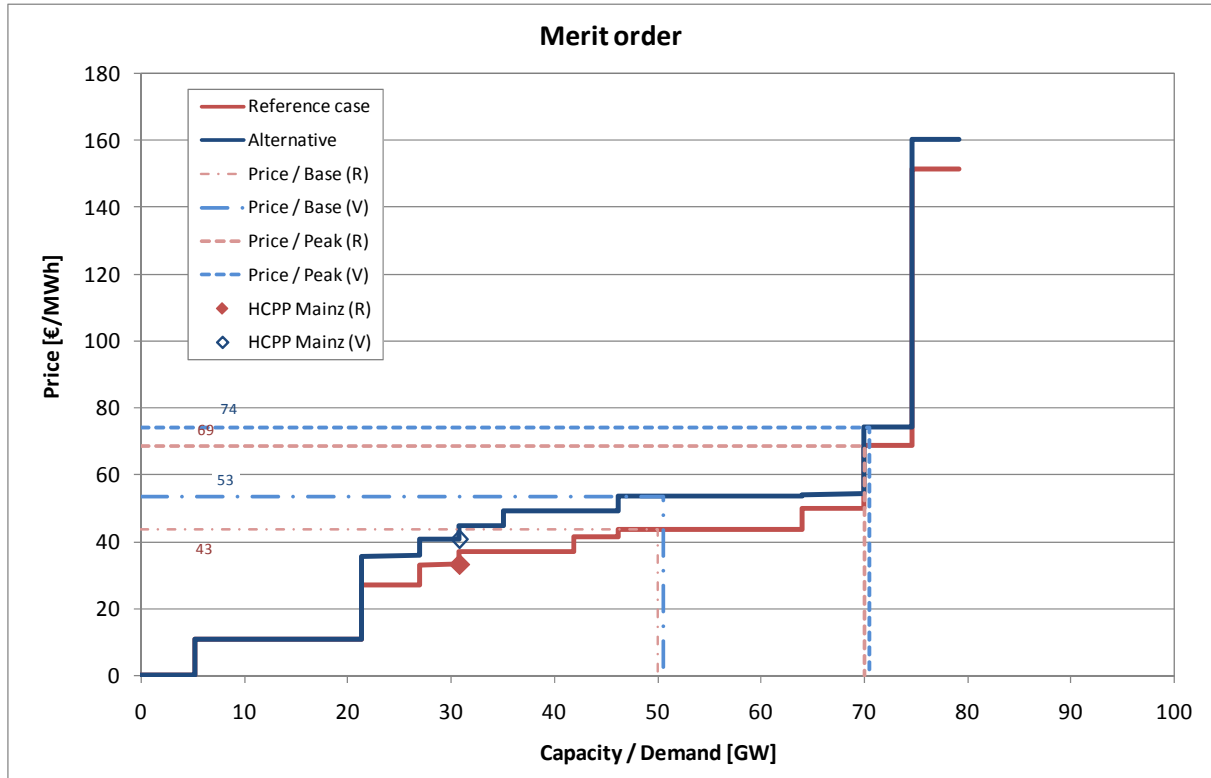


Figure 10. Changes in the merit order curve (2009) for two exemplary demand curves at a 50% increase in CO₂ prices (V) compared to the reference case (R). The diamonds show the position of a new hard-coal-fired power plant.

Both preceding illustrations are only snapshots of two typical hours. To get a general overview, we would have to look at a longer period of time; typically all the hours of one year. This is calculated with the aid of a distribution function for demand derived from the sum of all demand curves. Figure 11 illustrates the results of such a computation. It shows:

- the price of electricity (blue)
- the marginal costs of a new hard-coal-fired power plant (red)
- its contribution margin (=electricity price–marginal costs; green)
- its profit (= contribution margin–fixed costs; orange)

For this study, a simplified model of the electricity market was used that takes the most important types of power plants into account. A more exact analysis could be done using a comprehensive model calculation of an electricity market model that includes the entire stock of German power plants and expected changes. However, earlier calculations of this type for other power plants reached similar results, proving that a simplified model is sufficiently representational for the purpose of this analysis (Pehnt et al. 2007).

In the reference case, the planned hard-coal-fired power plant is, as illustrated above, economically viable by a small margin under the postulated conditions. An increase in the price of coal makes it no longer economically viable. An increase in the price of gas greatly improves viability.

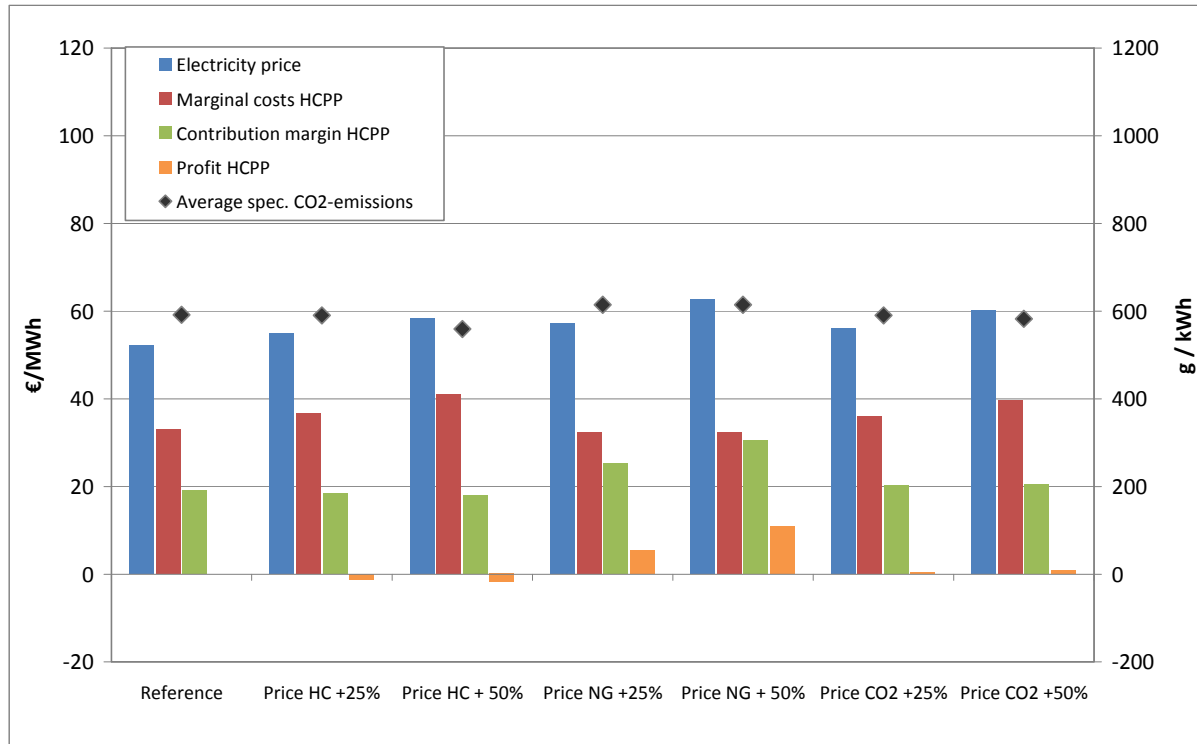


Figure 11. Consequence of variations in price parameters based on today's stock of power plants.

In the short-term, an increase in the price of CO₂ improves the economic viability of a new hard-coal-fired power plant. This is due to the fact that new hard-coal-fired power plants are more efficient than old hard-coal-fired power plants, which are sometimes the marginal power plant. Therefore a new plant's supplementary income due to higher electricity prices is higher than the additional costs for emission allowances. And they are not muscled out of the market as there are no alternative generators. In the mid- and long-term however, this will change as hard-coal-fired power plants become the cause of high CO₂ prices (see chapter 3.3).

However it must be noted that in all scenarios illustrated in figure 11, the average CO₂ emissions from electricity production are at around 600 g/kWh (green diamond, right vertical axis). Rising CO₂ prices have little effect on average specific emissions if there are no other changes. This is an important result which we shall examine more closely below.

3.2 Effect of electricity feed-in from renewable sources

Many renewable energy facilities have little or no marginal costs. This is true particularly of wind power, photovoltaic and solar-thermal power plants and thus for the most promising technologies. Biomass power plants are an exception, however they are of only limited importance.

Electricity from these facilities – whether it is traded on the market or feed-in tariffs are set by the German renewable energy law – causes the merit order curve in figure 4 to move to the right and prices to fall.



Figure 12 illustrates a scenario in which electricity from wind power covers 10 GW rather than 1 GW as in the reference case. In this case, the price of electricity drops from 43 to 37 €/MWh at times of low-capacity and from 69 to 59 €/MWh during high-capacity hours.

This has two potential consequences for conventional power plants. First, their revenue decreases because the price of electricity sinks; second, at periods during which sufficient electricity from renewable energy sources is available, they could be pushed out of the market altogether. Both lead to decreased earnings and thus also lower contribution margins for conventional plants.

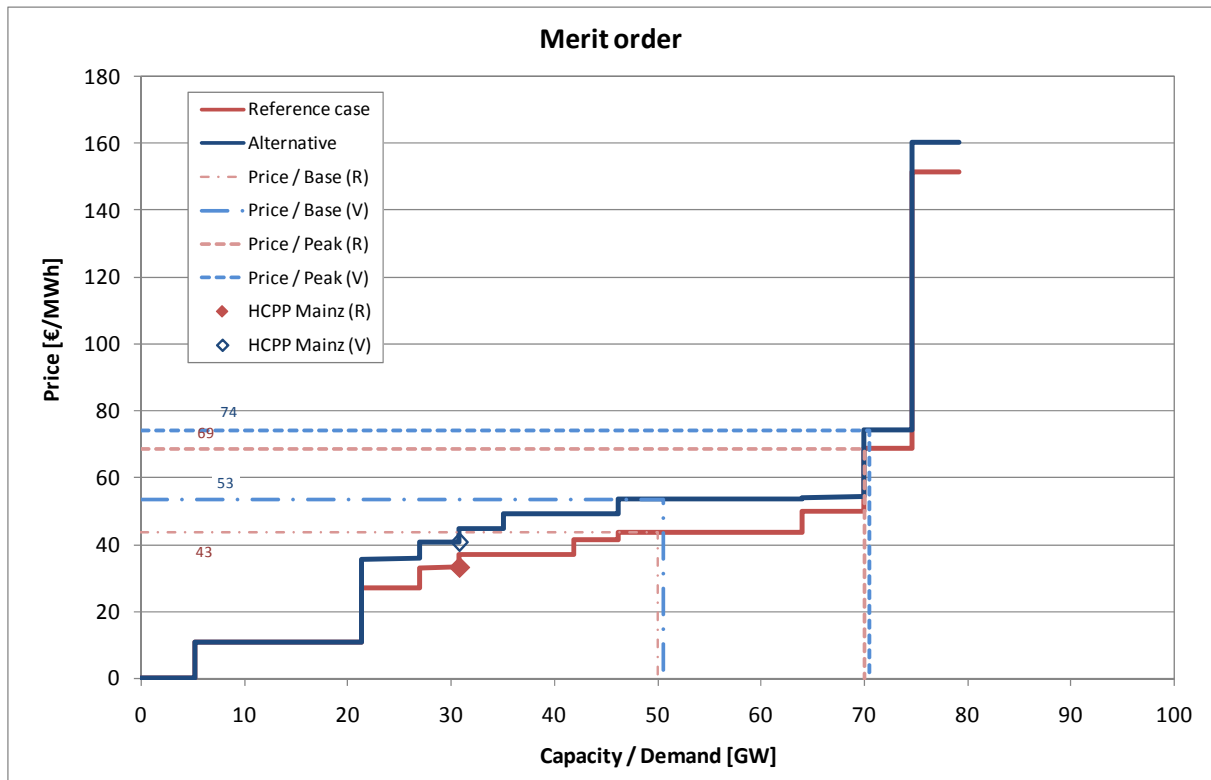


Figure 12. Change in the merit order curve (2009) when wind power supplies 10 GW (V) rather than 1 GW (R). The diamonds mark the position of a new hard-coal-fired power plant.

Although hard-coal-fired power plants have a better position in the merit order, they are hit harder by this scenario than gas-fired power plants because their investment costs are higher and because they are more difficult to regulate and thus less adaptable to fluctuating demand.

In the long-term, we can assume that there will no longer be a so-called base load. Figure 13 illustrates this by a representation of the remaining energy demand. The remaining energy demand is the difference between the total electricity demand and the electricity produced by renewable energies. This must be generated by conventional power plants. Figure 13 shows that in 2006, the remaining energy demand was never less than 30 GW. However a scenario based on the increased use of renewable energy as planned by the German federal government shows that this structure shall change completely by 2030, often resulting in a low or even non-existent remaining energy demand.

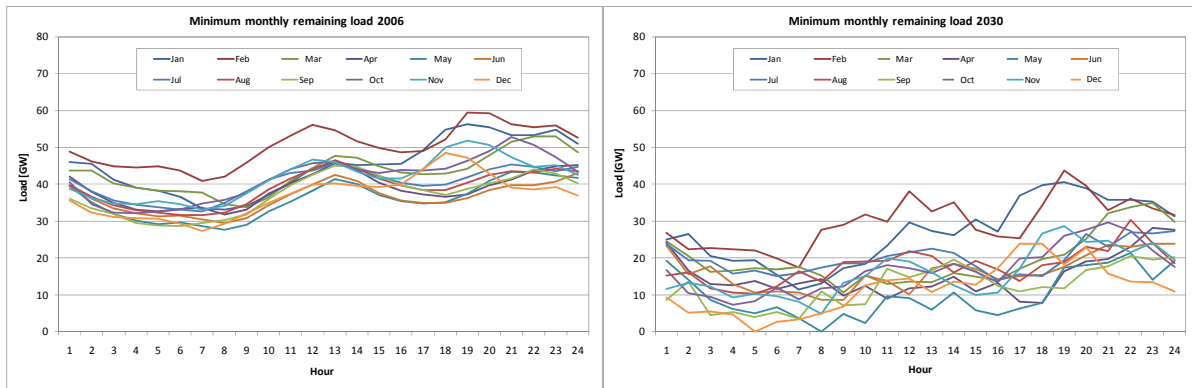


Figure 13. Minimum remaining energy demand (demand - electricity from renewable energy sources) 2006 and 2030 (calculation by author).

At any given moment, conventional power plants will need to be able to cover the ever-changing difference between changing demand and fluctuations in feed-in from renewable energy sources.

3.3 Changes in the power plant stock

This chapter examines the effect changes in Germany's stock of power plants will have on the electricity market. To calculate this, we assume a variety of changes in the current power plant stock as illustrated in table 10. The mean price of electricity, the marginal costs of a new hard-coal-fired power plant, its contribution margin and its profit were calculated using the changed merit order and the demand profile illustrated in figure 5. Figure 14 summarizes the results of this calculation. The table at the bottom of the graphic shows, which components and parameters were changed. The reference case (R) is on the far left-hand side. In addition, figure 14 shows the average CO₂ emissions of the power plant stock (green diamond, right vertical axis).

3.3.1 Building new electricity production facilities

Adding for example 5 gigawatts (GW) of electricity from a new offshore wind farm – if all other conditions remain the same – would lower the average price of electricity by 7% (figure 14, scenario 1). This is sufficient to make a new hard-coal-fired power plant commercially inviable.

Building a 5 GW hard-coal-fired power plant (scenario 2) or 5 GW natural-gas-fired combined cycle power plant (scenario 3) would decrease the price of electricity by 14% or 13% respectively. The decrease is greater than in the case of the wind farm, because these power plants have more operating hours per year. In these two cases as well, the coal-fired power plants would not be economically viable.

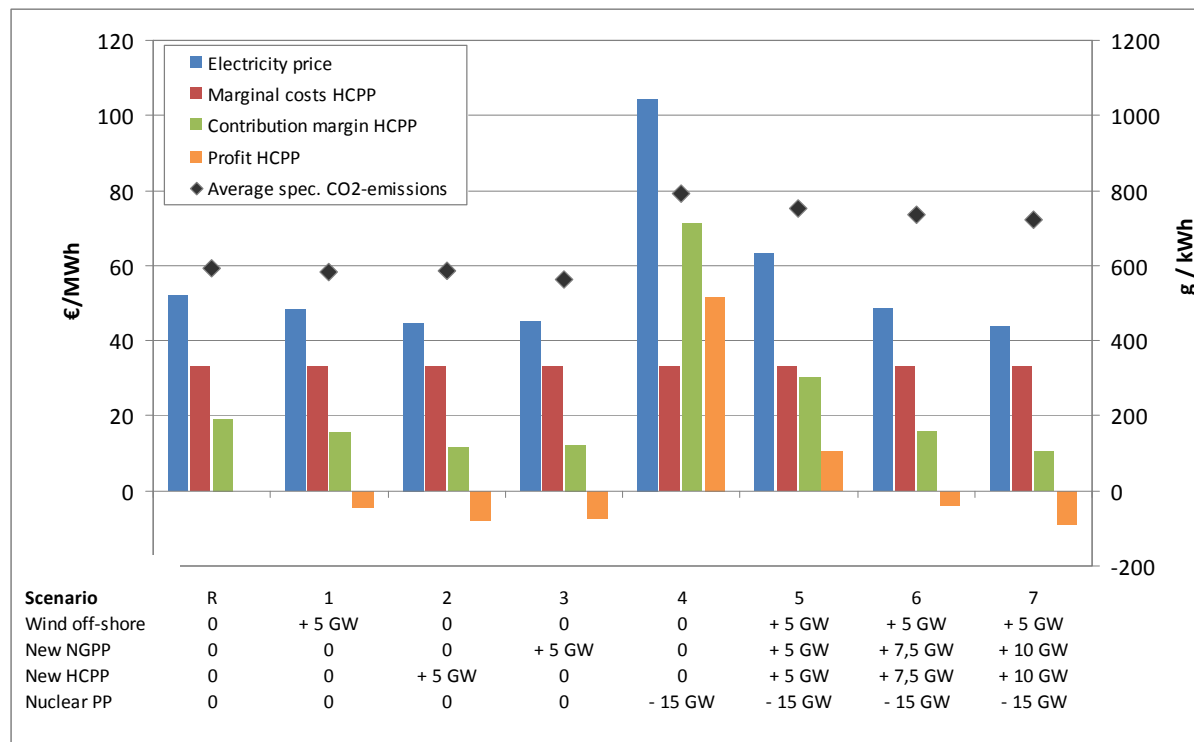


Figure 14. Effects of changes in the power plant stock on the economic viability of a new hard-coal-fired power plant. A CO_2 price of 20 €/t has been assumed in all scenarios.

It is important to note that every investment in increased power plant capacity tends to reduce the price of electricity. This is necessarily so, since a new power plant must always have lower marginal costs than existing power plants, otherwise it would have no chance on the market. This fact presents a major hurdle to investments in new power plants (Groscurth and Bode 2009). Economists regularly argue that production capacity shortages cause the price of goods to rise and provide incentive to invest in new capacities. However in the electricity market, the long lead time for the construction of new power plants is problematic. Electricity prices may of course rise when power plant capacities are at their limit. As soon as the missing capacity is met however, the price of electricity falls again, so that new plants no longer profit from higher prices.

The next scenarios assume that nuclear power plants with a total of 15 GW are shut down by 2020 as currently mandated by law. If the missing capacity is not substituted, the price of electricity rises dramatically, making a new hard-coal-fired power plant economically viable (scenario 4). This scenario is however unrealistic. Different scenarios are examined to replace the missing capacity.

Assuming the nuclear energy phase-out proceeds as planned is in favor of new hard-coal-fired power plants. Without this phase-out however, the position of a new fossil fuel-fired power plant would have a less favorable position in the merit order and a lower contribution margin.

Building offshore wind farms, hard-coal-fired power plants and gas-fired combined cycle power plants with a capacity of 5 GW of electricity each would make new hard-coal-fired power plants less profitable, but would not yet make the investment questionable (scenario



5). In this case, the price of electricity would be around 60 €/MWh. This value is slightly above the reference case because wind farms, as opposed to nuclear power plants, do not generate constantly.

Newly generating 5 GW of wind power and 7.5 GW from both natural-gas-fired and hard-coal-fired power plants would decrease the price of electricity to around 50 €/MWh (scenario 6). This value is lower than in the reference case because the power no longer generated by nuclear power plants is replaced completely by conventional facilities and additional capacity is available from wind energy. In this scenario, new hard-coal-fired power plants are commercially unviable.

If alongside 5 GW of wind energy, hard-coal-fired and gas-fired power plants with a capacity of 10 GW each are built, the price of electricity would fall to around 45 €/MWh, further worsening the situation for new hard-coal-fired power plants (scenario 7).

3.3.2 Effects on the price of CO₂

At this point however, another factor is decisive: In all scenarios examined until now, the average specific CO₂ emissions remain at 600g/kWh or – in the case of a nuclear energy phase out – even higher. However figure 2 shows that this value must fall to under 500 g/kWh by 2015 and to around 400 g/kWh by 2020 if long-term emission reduction objectives are to be met. Buying additional emission allowances in these dimensions is unrealistic, considering the fact that all other countries would then have to make corresponding reduction commitments.

If CO₂ emissions are too high, there will be a significant demand for emission allowances. This will lead to scarcity and thus rising CO₂ prices. In the end, CO₂ prices will continue to rise until countries remain within their emission budgets. There are only two ways that this can occur. Consumers, due to higher prices, could reduce their demand – whether by investing in more efficient devices or by renouncing certain services. Alternatively, the power plant stock could be changed so that the same amount of electricity is produced with lower emissions.

First however, the price of CO₂ will rise. There are as yet no sound economic models to determine the interconnection of CO₂ emissions and CO₂ prices. Since the CO₂ market functions on an EU – and increasingly on a global – level, the creation of such a model is quite difficult if not impossible. As usual in such cases, plausibility scenarios are then created to determine how the price of CO₂ might react to certain emission levels. The results are summarized in figure 15.

A rise in the price of CO₂ from 20 €/t (as in the reference case) to 40 €/t causes average emissions after the nuclear energy phase-out to fall from a level of 700 g/kWh only to around 600 g/kWh (scenario 8). This is due to changes in the merit order. The price of electricity rises to 60 €/MWh.

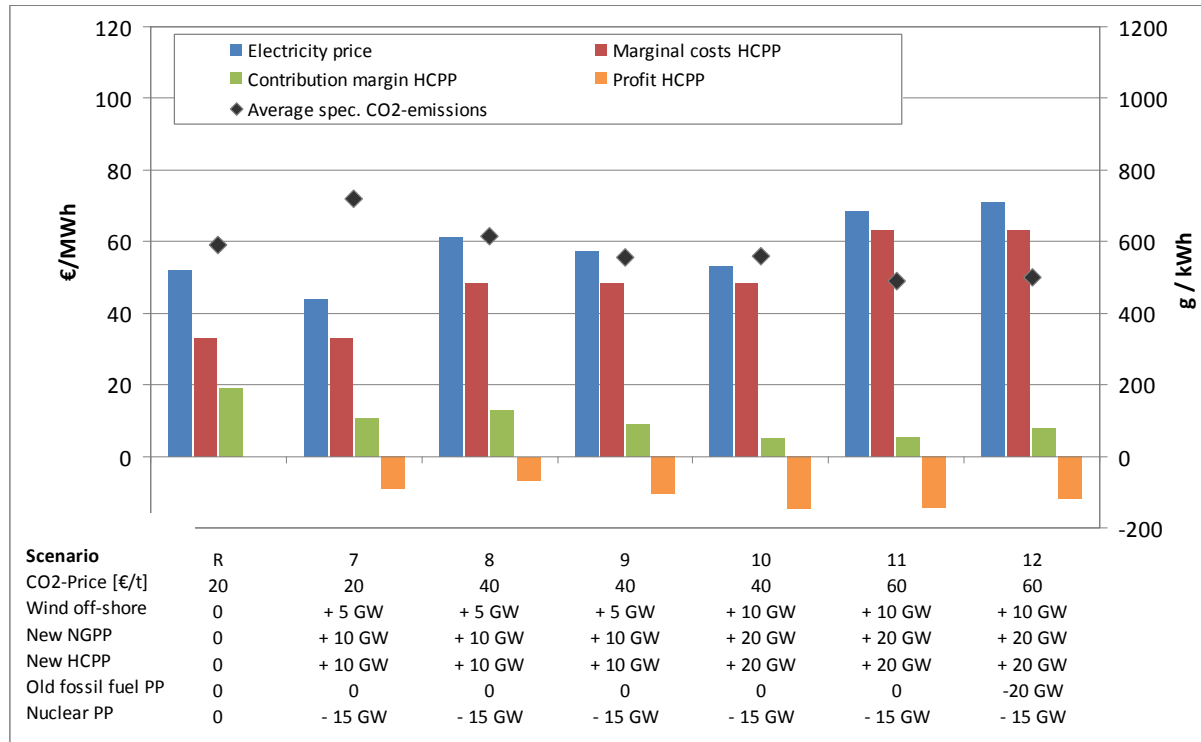


Figure 15. Effect of rising CO₂ prices on the economic viability of a new hard-coal-fired power plant.

Should the rise in electricity prices cause demand to fall by 20%, specific CO₂ emissions fall to 550 g/kWh (scenario 9). A reduction of this magnitude by 2020 is a very ambitious goal if it is to be reached by increased efficiency. It is however unlikely that consumers would be willing to forego services; they are more likely to demand a watering down of climate protection goals if asked to do so.

If instead further attempts are made to attack the problem using technology and 10 GW of wind power as well as 20 GW from new hard-coal-fired and from new gas-fired power plants are added to the energy mix, average CO₂ emissions sink to 560 g/kWh at a constant CO₂ price of 40 €/t (scenario 10). In this case, the price of electricity is at around 53 €/MWh.

As the emissions level is still too high, the price of CO₂ will continue to rise. Not until it reaches 60 €/t are average emissions of under 500 g/kWh realized (scenario 11). The price of electricity is then 68 €/MWh.

If we assume an additional 20% decrease in demand, the average CO₂ emissions of electricity production are 420 g/kWh. Absolute emissions are reduced disproportionately by 33%.

What has not yet been taken into account is that alongside nuclear power plants, fossil fuel-fired power plants will also be shut down. This plays a subordinate role, as new plants would have forced these plants from the market in any case. However if the model calculation assumes shut downs adding up to 20 GW (scenario 12), the price of electricity and CO₂ emissions does rise slightly. This is because gas-fired power plants are then also shut down.

In none of these scenarios are new hard-coal-fired power plants economically viable. This was to be expected; when emissions trading is effective, it ensures that emission budgets are not exceeded. Ignoring for a moment reductions in demand, CO₂ emissions can only decrease by the amount necessary to achieve climate protection objectives if the power plants

with the highest specific emissions are driven from the market. This applies in particular to new hard-coal-fired power plants.

Table 2 shows the current stand of conventional power plants in planning. It is fairly sure that new coal-fired power plants (including lignite-fired plants) generating more than 7 GW of electricity will be built, making it more difficult to reach CO₂ reduction goals. New data even maintains that hard-coal-fired power plants with a capacity of over 10 GW will be constructed (BUND 2009). Each new hard-coal-fired power plant exacerbates this situation.

Table 2. Stand of conventional power plants under construction or in planning for 2015 in Germany (BMWi 2008).

	Under construction	Very certain	Fairly certain	Uncertain	Total
	MW				
	Without probability weighting				
Hard coal	1.800	1.510	6.854	8.030	18.194
Lignite	2.905	0	0	1.850	4.755
Natural gas	2.351	0	2.179	3.670	8.200
Total	7.056	1.510	9.033	13.550	31.149
	With probability weighting				
	PW = 100%	PW = 66%	PW = 33%	PW = 0%	
Hard coal	1.800	1.007	2.285	0	5.091
Lignite	2.905	0	0	0	2.905
Natural gas	2.351	0	726	0	3.077
Total	7.056	1.007	3.011	0	11.074

If no new hard-coal-fired power plants are built, but instead 40 GW natural-gas-fired power plants, a CO₂ price of 30 €/t would be sufficient to change the merit order so that the average CO₂ emission would lie at 430 g/kWh. If we assume the price of coal remains constant at 8 €/MWh, the electricity price reached by new coal-fired power plants (€68/MWh) is equal to the price reached when gas costs 30 €/MWh. This means that the price of gas would have to rise to the summer 2008 high before this scenario makes less economic sense than a scenario with new hard-coal-fired and gas-fired plants. It does not become worse than the latter unless gas prices continue to rise without the price of coal also rising. However, as 2008 data shows, this is very unlikely (figure 7). In 2008, the price of coal increased even more than the price of gas.



3.4 General conclusions

All in all, investors face a dilemma. On the one hand, we need new power plants. On the other hand, the current rules of the market provide little incentive for investments in new facilities. The situation is made more difficult by the increased use of renewables and climate policy objectives.

To achieve long-term climate protection goals, long-term changes in the stock of Germany's power plants are necessary. Replacing existing fossil-fuel-fired power plants with new, more efficient plants of the same type is insufficient. To the contrary, this makes achieving the necessary long-term reduction of CO₂ emissions more difficult, if not impossible.

A reduction in demand can make an important contribution. To date however, reduction objectives by increasing efficiency lie only at 13%. Potentially, increased efficiency could lead to a reduction of at least 30%. This does not however consider quantity effects which could increase the demand for electricity. Increased efficiency alone will not be enough to reach climate protection objectives. A contribution by decreased demand can be forced by very steep increases in electricity prices. However the concurrent economic and social consequences make the political feasibility and acceptability of this strategy questionable.

Building new hard-coal-fired power plants today will in the near future force society to choose either to close these plants prematurely, causing considerable economic losses, or to abandon climate protection goals. It is already foreseeable that the companies affected will lobby intensively for their facilities.

Building hard-coal-fired power plants leads to rising CO₂ prices and thus also to higher prices for electricity. Hard-coal-fired power plants thus do not guarantee consumers affordable electricity prices long-term, but rather lead to considerable additional economic risks.

However since there are also no incentives for the construction of gas-fired power plants, it must be asked whether the liberalized market can provide a solution at all or whether an integrated concept for electricity production in Germany or even Europe is not necessary.

4 THE PLANNED HARD-COAL-FIRED POWER PLANT IN MAINZ

4.1 Electricity production costs

The planned hard-coal-fired power plant in Mainz will have a gross electrical output of around 820 MW. At 7.500 operating hours per year, it will have an annual electricity production of not quite 6 terawatt hours (TWh/a). To reach this goal, assuming an average conversion efficiency of almost 45%, hard coal with an energy content of almost 13 TWh/a is needed. The power plant emits more than 4 million tons of CO₂ annually. The technical data is summarized in table 3:

Table 3. Technical data of the planned hard-coal-fired power plant in Mainz.⁹

Technical data	Unit	Value
Gross capacity	MW_el	823
Net capacity	MW_el	757
Capacity utilization rate		44.8%
Electricity production	TWh_el/a	<i>5.68</i>
Fuel input	TWh_f/a	<i>12.7</i>
CO ₂ emissions		
Fuel-specific emissions	t/MWh_f	<i>0.34</i>
Absolute emissions	Mt/a	<i>4.31</i>
Electricity-specific emissions	t/MWh_el	<i>0.76</i>

Assuming specific investment costs (including connection costs and other additional costs) of 1.700 €/kW, the total investment is almost 1.3 billion euro. We have assumed that 1 bill. euro will be borrowed at an annual interest rate of 4.5%. Interest returns of 10% are assumed for the equity capital. The amortization period is 25 years.

For the sake of further examination, as initial values we assume the power plant can be in operation 7.500 hours per year, that the price of hard coal is at 8 €/MWh_f and that CO₂ emission allowances cost 20 €/t. Economic data and assumptions are summarized in table 4.

Table 5 illustrates the results of an initial computation of the electricity production costs. These add up to around 300 mill. euro per year or 53.6 €/MWh_{el}. Marginal costs add up to 34.5 €/MWh.

There is little heat extraction planned. As a close approximation of real costs, one can therefore assume that income from selling heat and additional costs of the power plant cancel one another out. Heat extraction is therefore not examined more closely in this economic viability assessment.

⁹ Here and in the following, values in italics have been calculated, values in normal print are givens.



Table 4. Economic data and conservative estimates for the planned hard-coal-fired power plant in Mainz.

Economic data	Unit	Value
Investment		
Specific investment	€/kW _{el}	1.700
Total investment	M€	1.287
Equity capital		287
Loan capital		1.000
Interest		
Interest from equity capital		10.0%
Interest on loan capital		4.5%
Amortization period	a	25
Planned full-load hours	h/a	7.500
Hard coal price	€/MWh _f	8.0
CO ₂ price	€/t	20

Table 5. Estimate of the electricity production costs of the planned hard-coal-fired power plant in Mainz using the conservative estimate in table 4 (calculation by author).

Electricity production costs	Annual	Specific
	M€/a	€/MWh _{el}
Capital costs	99	17.4
Other fixed costs	9	1.6
Fuel costs	101	17.9
CO ₂ costs	86	15.2
Other variable costs	9	1.5
Sum	304	53.6
Marginal costs		34.5

4.2 Position of the Mainz power plant on the market

In the merit order in figure 4, the Mainz power plant would operate in times of high and low demand, making the planned operating time of 7.500 h/a at first seem realistic.

If we average the electricity price in the merit order with the aid of the distribution derived from all demand curves in figure 5, we arrive at an average electricity price of 52 €/MWh_{el}, which is insufficient to cover the electricity production costs of 53.6 €/MWh. Not until the expected interest rate on the equity capital is lowered to 6% do the electricity production costs fall to 52 €/MWh.

It would however be premature to come to a conclusion based on these first results. As we have seen in chapter 3, it is not enough to make a static examination. Therefore in the following we shall show how changes in key parameters affect the basic economic data of the planned power plant.

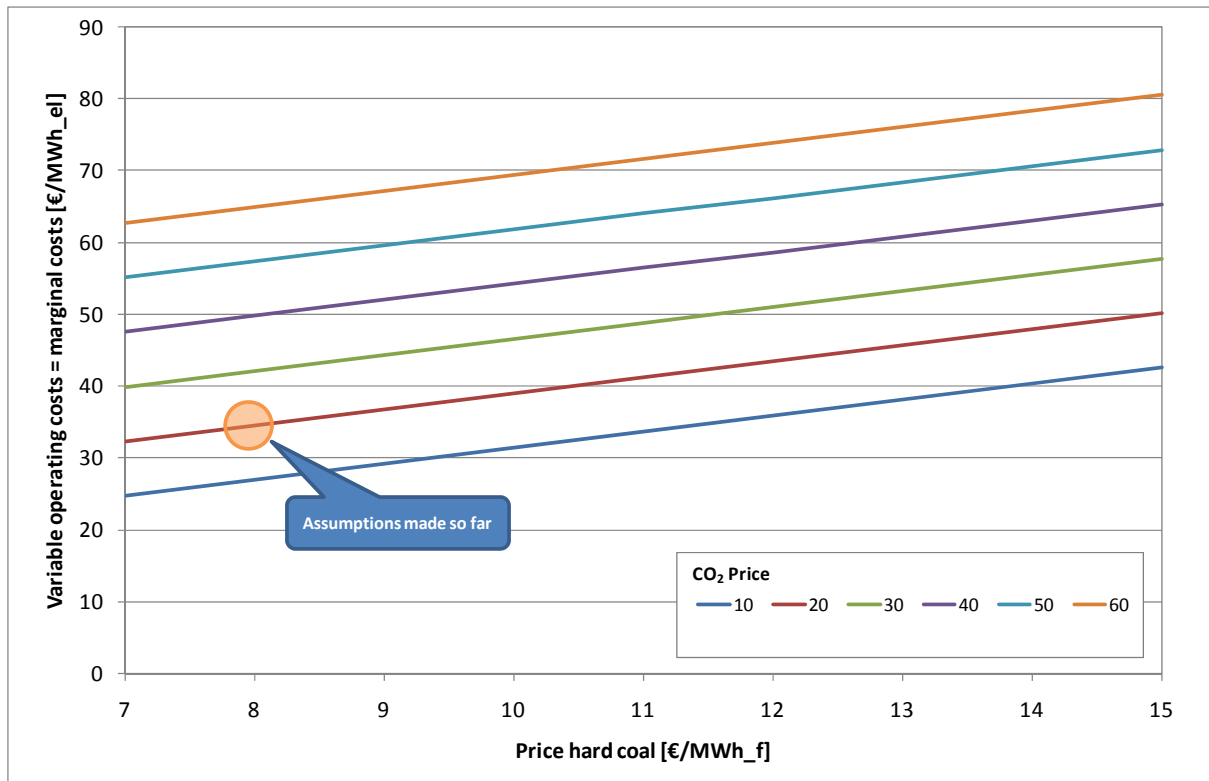


Figure 16. The Mainz hard-coal-fired power plant's variable operating costs' (marginal costs) dependency on the price of hard coal and CO₂ (calculation by author).

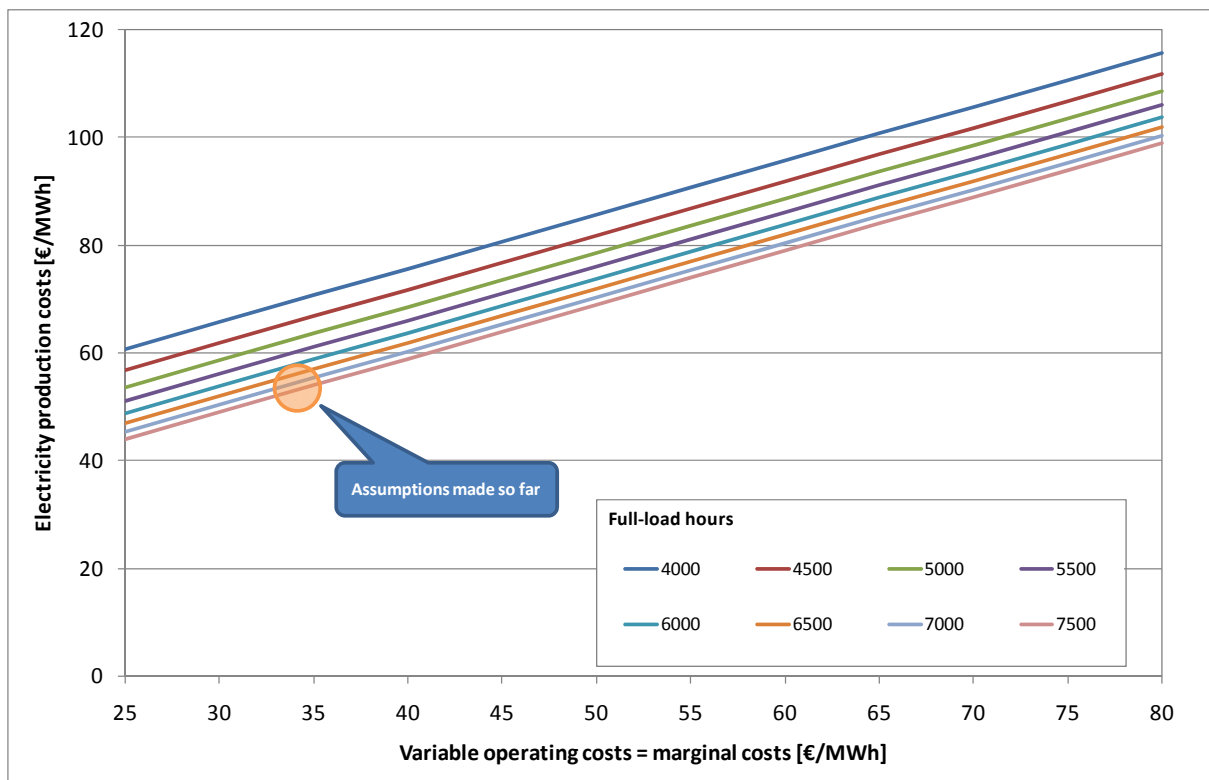


Figure 17. The Mainz hard-coal-fired power plant's electricity production costs' dependency on variable operating costs (marginal costs) and utilization capacity (hours of full capacity) (calculation by author).



4.3 Kraftwerke Mainz-Wiesbaden AG's record

Occasionally the argument has been made that the Mainz hard-coal-fired power plant is needed to secure supply in the region. To this it must be said that a regional view of the power supply situation is inappropriate in a liberalized electricity market. Crucial rather are the capacity available on the German market and the existing grid capacity. In light of the long-term requirements of sustainable, environmentally sound electricity production, extending the grid should be given priority over local conventional power plants.

Furthermore, Kraftwerke Mainz-Wiesbaden AG owns one of the most modern gas-fired power plants in Germany. They have however stated that this plant needs to be shut down when the present gas supply contract ends in 2014, because no more gas can be procured. If this were a true supply problem, the federal government would have to attend to it immediately. However, great efforts are already being made to build new pipelines to ensure Germany's gas supply. If it is only a price problem, it should be remembered that higher gas prices lead directly to higher spot market prices for electricity. The existing gas-fired power plant, which has a better merit order position than other gas-fired power plants, will profit from this price raise. A contribution margin most definitely exists, because it is more efficient than the gas-fired power plant that acts as the marginal power plant. From a commercial point of view, it therefore makes no sense to shut the plant down.

4.4 Consequences for the planned hard-coal-fired power plant in Mainz

Figure 16 shows the dependency of the variable operating costs or marginal costs on the price of hard coal and of CO₂. Figure 17 illustrates the dependency of all electricity production costs on the marginal costs and the power plant's capacity utilization. From both figures one can see that the assumptions made until now are on the optimistic end of possible parameter values. However the observations made in chapter 3 revealed a variety of risks faced by new hard-coal-fired power plants:

- If more power plant capacity is created than is taken off the grid, the price of electricity sinks to the extent that new power plants no longer generate a sufficient contribution margin.
- If the nuclear energy phase-out is rescinded, new conventional power plants will have a less advantageous position in the merit order and less operating hours.
- The increase of electricity production from renewable energy sources with zero marginal costs will result in ever more hours at very low spot market prices in the not too distant future, which will have a large effect on revenues. As figure 13 shows, the structure of the demand profile conventional power plants will need to meet shall change drastically in the near future. This will lead to less annual operating hours for conventional plants. Furthermore, this requires that these facilities be highly controllable. Gas-fired power plants are better equipped to deal with both these parameters than are hard-coal-fired power plants.
- Investors in new hard-coal-fired power plants also need to know that emissions trading could in the mid-term make their facilities uneconomical.



All of these points burden hard-coal-fired power plants' revenue side. On the expense side, we can expect both rising CO₂ prices and rising prices for hard coal. When the current economic crisis is resolved and the demand for gas and oil rises and with it their prices, a similar development can be expected for hard coal. This was shown during the sharp rise in fuel prices in the course of 2008.

Since the power plant is at the margin of economic viability even under optimistic parameters (figures 16 and 17) each worsening of these parameters represents a serious risk for investors. The economic consequences of an increase of power plant capacity and a rise in the price of CO₂ can be seen in figure 14 and figure 15. In none of the realistic scenarios are new hard-coal-fired power plants economically viable.

Weighing chances and risks, taking economic considerations and climate policy into account, we advise in particular public investors not to build hard-coal-fired power plants.



APPENDIX

Reference case data

Table 6. Base data initial values for the scenarios.

Base data	Unit	Reference case
Fuel prices		
Lignite	€/MWh _f	4.0
Natural gas	€/MWh _f	20.0
Renewable energy	€/MWh _f	0.0
Oil	€/MWh _f	40.0
Hard coal	€/MWh _f	8.0
Uranium	€/MWh _f	3.5
Environmental data		
CO ₂ price	€/t	20.0
Specific CO ₂ emissions		
Lignite	t/MWh _f	0.39
Natural gas	t/MWh _f	0.20
Renewable energy	t/MWh _f	0.00
Oil	t/MWh _f	0.27
Hard coal	t/MWh _f	0.34
Uranium	t/MWh _f	0.00
Investment data		
Interest rate	1/a	10%

Table 7. Initial values for the total stock of power plants in the scenarios.

Power plant type	Capacity (GW)
Old oil-fired gas turbines	5
Old lignite-fired power plants	13
Old natural gas combined cycle power plants	7.5
Nuclear power plants	19
Old hard-coal-fired power plants	21
Old hydroelectric plants	4.7
Gas turbines	5
New wind farm (off-shore)	0
New wind farm (on-shore)	23
New lignite-fired power plants	6
New natural gas combined cycle power plants	4.5
New hard-coal-fired power plants	4



Abbreviations

°C	degrees Celsius
..._el	... as regards electricity
..._f	... as regards fuel
€	euro
€/MWh	euro per megawatt hour 1 €/MWh = 1/10 c€/kWh
a	year (annually)
CCGT	natural-gas-fired combined cycle power station (combined cycle gas turbine)
CO ₂	carbon dioxide
EEX	European Energy Exchange (electricity market in Leipzig)
EU	European Union
EU-ETS	European Emissions Trading System
g/kWh	specific CO ₂ emissions in gram per kilowatt hour
GW	gigawatt = 1.000 MW
h	hour
h/a	hours per year
HCPP	hard-coal-fired power plant
IECP	Integrated Energy and Climate Program (of the German federal government)
kW	kilowatt = 1.000 watt
kWh	kilowatt hours = 1.000 watt hours
MW	megawatt = 1.000 kW
MWh	megawatt hours = 1.000 kWh
MWh_f	megawatt hours of the energy content of fuel
MWh_el	megawatt hours of electricity
MWh_th	megawatt hours of heat
t	tons
W	watt (electrical power)
Wh	watt hours (physical); 1 Wh = 3.600 Ws = 3.600 J



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