Maren Hille, Wolfgang Pfaffenberger [1]

Power Generation in Germany: How to Close the Gap in Generation Capacity in the Context of a Liberalized Energy Market

Abstract

This paper describes the upcoming capacity gap in the German power market, analyses possible solutions to the investment paradox and shows the possible future contribution of relevant energy sources to power generation. Options for a future "energy-mix" are discussed and evaluated in consideration of security of supply, profitability and environmental compatibility.

Keywords:
Generation Capacity, Energy Production Cost, Investments in a liberalized Energy Market, Market Mechanisms, CO_2-Emission Trading,

1 State of Generation

1.1 Structure of Generation

Electricity production in Germany at the moment is heavily based on coal and nuclear energy as can be seen from figure 1. Nuclear energy and lignite supply base load energy as can be seen from the production capacity ratio represented in figure 2.

The contribution of renewable energies is relatively small but has increased enormously during the last years due to their promotion by special feed in tariffs based on the renewable energy law. Particular wind energy increased strongly. At the end of 2003 the installed capacity was 14.6 GW and production came to 18.6 TWh (see Table 1).
((Figure 1))

Table 1: Wind Energy 2001 to 2003
[Source: www.bmu.bund.de/de/1024/js/sachthemen/erneuerbar/windenergiedaten/]

	2001	2002	2003
No. of Installations	11,440	13,760	15,387
Capacity [MW]	8,754	12,001	14,609
Production [TWh]	11.0	17.2	18.6

[1] Dr. Maren Hille, research associate bremer energie institut, Bremen, Dr. Wolfgang Pfaffenberger, Professor at International University Bremen and director of bremer energie institut. An extensive report in German „Investitionen im liberalisierten Strommarkt: Optionen, Marktmechanismen, Rahmenbedingungen" ist erhältlich über www.bremer-energie-institut.de Veröffentlichungen 2004.

((Figure 2))

Due to restrictions in available sites as well as network capacities the speed of increase of installations in inland areas will be reduced in the future. Network operators have to cope with the fluctuations in wind. Figure 3 shows the short time variation in supply of electricity from wind converters in a regional network with high density of wind energy installations.
((Figure 3))

1.2 Capacity development

a. <u>capacity gap</u>

Within the next two decades a large part of generation capacity in Germany will be closed down due to:

- Retirement of fossil power stations at the end of their economic life time (about 20 to 30 GW) and
- Decommissioning of nuclear power stations due to the Nuclear Power Act that regulates the phasing out of nuclear energy (about 20 GW).

All together, the reduction is expected to amount to 40-50 GW up to 2020 or almost 50% of the overall generation capacity that is installed today (see figure 4). Assuming constant power demand this requires investments in the amount of 30-40 billion Euro.

((Figure 4))
b. <u>power balance forecast</u>

In consequence of the described capacity development, in the next two decades we expect a reduction in the ratio of remaining capacity to load and capacity as can be seen from figure 5. Whereas total installed capacity is increasing because of the expected expansion of wind energy the reserve margin goes down at a level that makes the system more vulnerable to supply risks in case of disturbances. We conclude from this that in order to avoid problems of security of supply investment in generation capacity that contributes to the security of supply in the system is overdue.

((Figure 5))

Will the market be capable of ensuring these investments? This question is of general importance in Europe as can be seen from a similar analysis for the whole UCTE region (see figure 6). It is expected that the remaining capacity will be

((Figure 6))

Generally the electricity industry is characterized by relatively low investment into generation, transmission and distribution. The share of investment into the electricity system in GDP has gone down considerably in most European countries (see figure 7).

((Figure 7))

Whereas the EU is setting up a regulatory framework favorable for a truly European market the narrowing down of capacity margins in many countries does not make it likely that regional shortages could be overcome by an increase in cross border trade. An increase in trade would also require an extension of transport capacities. It can be questioned whether such investment should have the same priority as investment into generation.

2 Investment in the liberalized power market

2.1 The investment problem

The scheduling of power plants is based on an economic criterion. A power plant can only contribute to supply if the price at a certain time does at least cover the operating costs (especially fuel costs). Market opening of the power market according to the European directive has lead to new forms of trade of electricity. Producers, traders and customers have to consider the risk of various options for buying or selling electricity and mix their portfolios accordingly.

Before the market opening the question of supply or demand usually was not whether there would be enough capacity available at a certain time but rather how to sell or buy this capacity for a good price.

The present European market, however, runs into capacity shortages as it has been shown. In an open market security of supply is desired by customers but not necessarily supplied by producers due to the so called investment paradox.

((Figure 8))

In an open market the marginal cost of the most expensive power plant that is necessary to satisfy demand determines the price. Figure 8 shows the principle. The price varies according to the use of installed capacities depending on the marginal cost of the various power plants. In the example the marginal supplier in the diagram does not earn any contribution to his fixed cost and might try to offer his product at a price above the marginal cost. Whether this is possible or not depends on the total available capacity. If capacity is abundant and offered by various suppliers the price will be near to marginal cost. If capacity is restricted the marginal supplier is in the strategic position to charge a price above his marginal cost. From the point of view of the supply side it is therefore desired to keep capacity margins low so that even marginal power plants can earn a contribution to their fixed cost.

Can we then expect investment into new generation?

((Figure 9))

It would require that new power plants can earn their total cost under competitive conditions. Figure 9 shows the problem. New installations will increase capacity and would have relatively low marginal cost due to better economic performance but on the other hand would not be able to earn their total cost. New generation capacity is only economic if due to an increase in demand or replacement of old capacity the capacity margin remains small so that power plants with high marginal cost have to be used frequently. This would lead to higher market prices that could also be sufficient for new power plants (see figure 10).

((Figure 10))

We can draw the following conclusions from this analysis:

Investment in new generation and replacement of old plants have to be synchronized. If more plants are closed than rebuilt this could lead to bottlenecks that in turn would be reflected in very strong price movements. In the situation of high demand capacity is below demand and an equilibrium could only be reached by using interruptible service.

The situation in the power market depends on the decisions of a large number of suppliers domestically and in Europe. From the point of view of the supplier a situation with small capacity margins is not without technical risks but economically necessary because it leads to a higher level of prices. Low capacity margins could lead to bottlenecks in supply for instance in extreme weather situations combined with failures of some power plants, disturbances in the network etc.

Security of supply rises through investment. The investor, however, does not profit from this. Can we expect in an open market situation that rivaling suppliers will replace their capacities in such a magnitude and time sequence that there will be no security of supply problems? This depends partly on the degree of information that competing suppliers have about the market. In the market of large generation due to the long lead times we can expect that enough information will be available so that this kind of ex ante coordination seems possible.

It helps to distinguish different segments of the power market. In the German situation we can distinguish four segments right now:

- Production from renewable energies eligible for feed in tariff with priority in the system
- Back up for fluctuating renewable energy
- Reserve power for TSOs
- Production for trade and customers

Reserve power for fluctuating renewables is presently supplied by the TSOs. The increasing share of renewables may necessitate to treat renewable generation just as fossil generation that is, obliging the power producer to take care of the reserve power needed for fluctuating generation by himself. This would lead to incentives for investment in this segment of the market.

Regarding the reserve needed by the TSOs it is necessary to install procedures for tender for these reserves that are long term enough to actually induce investment. At present the tenders are for short time periods only. This is meaningful in situations of overcapacity but may not lead to investment incentives if there are capacity shortages.

Regarding the production for trade and customers there is of course the option for every generator to supply the contracted volumes either on the basis of his own generation or by purchasing power from other generators. Price signals in the various segments of the spot and contract markets will lead to incentives for adjusting the portfolio between generation and purchase.

The markets however, in general are relatively short term and investment in central generating capacity is very long term. Whether and how this gap can be bridged depends very much on the availability of ex ante coordination forces in the market.

In the case of the German market it is clear that the market for the production of power is dominated by an oligopoly of only four large generating companies. It is quite clear that with increasing shortages of capacity these generators will be able to strategically influence the price so that it reaches the necessary level for investment to be economic. Typically this will lead to higher price volatility in the market.

In order for the market for new generation to function it is absolutely necessary to have clear rules of access to the power grid so that a higher price for power in the market will also be an incentive for independent power producers. In this way the relative market power of the incumbent producers can be restrained and a market solution to the investment problem becomes likely.

2.2 Comparison of energy options

Table 2 shows a comparison of available energy options by a number of important criteria. It becomes apparent that there is no ideal energy available for power production. Thus the question at stake is to find the energy mix that minimizes price and availability risks, reduces environmental emissions as far as possible, satisfies the need of the system to have a necessary flexibility for operation and at the same time is competitive.

Table 2: Qualitative comparison of energies available for power production
[Source: bremer energie institut]

	Coal	Gas	Renewables
security of supply	++	+	(+)
competitiveness	++	+	-
price risk	++	-	++
follow up cost *)	+	++	-
environment	-	+	++
flexibility	++	++	(-)

(+) Security of supply is generally to be expected. Wind and solar energy fluctuating supply. Biomass and hydro available for base load.

(-) flexibility: yes for biomass, partly for hydro, no for wind and solar.

*) like reserve power required, waste disposal etc.

Looking at the cost of supply the power price at the market has to cover the full cost of any option including capital cost whereas on the other hand for any hour of operation it has to cover at least the marginal cost (in case of fossil fuels the fuel cost of the particular plant). Looking at EEX prices of 2003 (see figure 11) the following conclusions can be drawn:

The average price was not sufficient to cover the cost of new plant.

((Figure 11)

Comparing variable cost to price shows that coal plants are able to supply base load power whereas natural gas can only supply medium load power.

This result refers to the present situation in the market but may not be fully relevant for investment for future generation. This is partly because EEX covers only a small fraction of the total market and the curve is a reflection of the present situation based on presently installed and available capacities. What will the curve look like in the future? It is very likely that prices in peak hours will rise very strongly whereas prices in other hours will not change very much (given fuel prices). So new generation units have to earn their capital cost mainly by serving at highly priced peak times.

((figure 12)

Looking at the relative competitiveness of different plants we compared various options available on the basis of investment and price data that we got from interviews with industry experts. Figure 12 shows the full cost of electricity production comparing brown coal, hard coal and natural gas plants with technology parameters for the year 2020, using the price variant "low" that is based on the average price of fuel of the last ten years. The competitive advantage of coal is clearly visible.

On the other hand there is the uncertainty about the future greenhouse gas reduction scheme. With the introduction of the European CO_2 emissions trading system a new regulatory risk becomes relevant. At first companies will get an endowment of certificates which will be based on past production and performance. It is unclear what price will develop for CO_2 certificates in the longer run particularly in the time after the first KYOTO round (2010 – 2012). This will strongly depend on the greenhouse gas reduction goals that will be set by national governments and in Europe. The next diagram shows the influence of CO_2 certificate price of 20 €/t. The cost of electricity production for all fossil fuels rises but much slower for natural gas because of the lower carbon content and the higher efficiency of combined cycle plants.

((Figure 13))

As the diagram shows with a CO_2 price of 20 €/t natural gas becomes the most economic option (see figure 13).

From this it can be seen that the most important variable for any future decision on the structure of generation lies in the hands of the government. In the longer run, for the economy it is necessary to use a reasonable energy mix. The NAP should be designed in such a way that such an energy mix can be realized in the future.

Where certain conditions can be met the use of combined heat and power (CHP) can be an efficient way of producing electricity and meeting environmental standards. This is because of the better use of primary energy that can be achieved by using the combined process (see Table 3). In times of high load for heat there is usually also a high load factor for electricity so that CHP can be used for space heating particularly. It can then contribute to saving capacities for a pure power production. In many cases CHP is the best form of supplying power and heat and at the same time leads to emission reductions. It is, however, necessary that there exits a load profile near the plant that allows economic transport of heat to the consumers. The limiting factor for the use of CHP is not on the electricity side but the heat side because of relatively high transport cost of heat. At present Germany produces about 50 TWh of electricity in the

CHP process. This could be increased by using some of the potential demand in industry which is not yet supplied by CHP and increasing the power to heat ratio by using combined cycle natural gas plants in the future. Thus an increase of present contribution of CHP to the system is to be expected.

Table 3: Primary Energy Advantage of CHP

Energy	Emission
Primary energy CHP plant	PE* specific emission= total emission
- primary energy separate power production	**-** emission from separate power
- primary energy separate heat	**-** emission from separate heat
= primary energy saved by CHP	**= emission change caused by CHP**

The contribution of renewable energy depends mainly on future legislation referring to renewable energy. Large potentials are seen in offshore wind energy. It seems too early to judge this option as too many parameters are still unclear such as: cost of investment and operation, ability of the system to adapt to the reserve requirements, willingness to pay by the consumers especially industrial consumers, ability of the network operators to extend their network to transport this energy to the centers of consumption or willingness of governments to allow extension of networks.

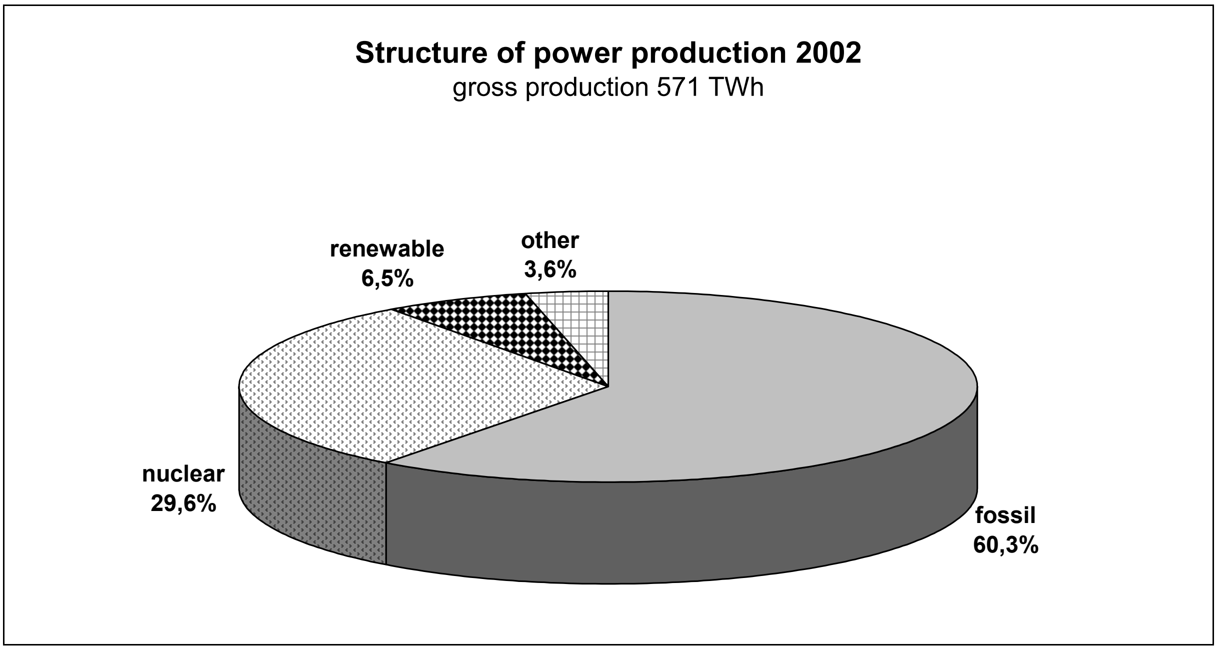

Figure 1: Power Production by Energy Sources 2002, [Source: DIW]

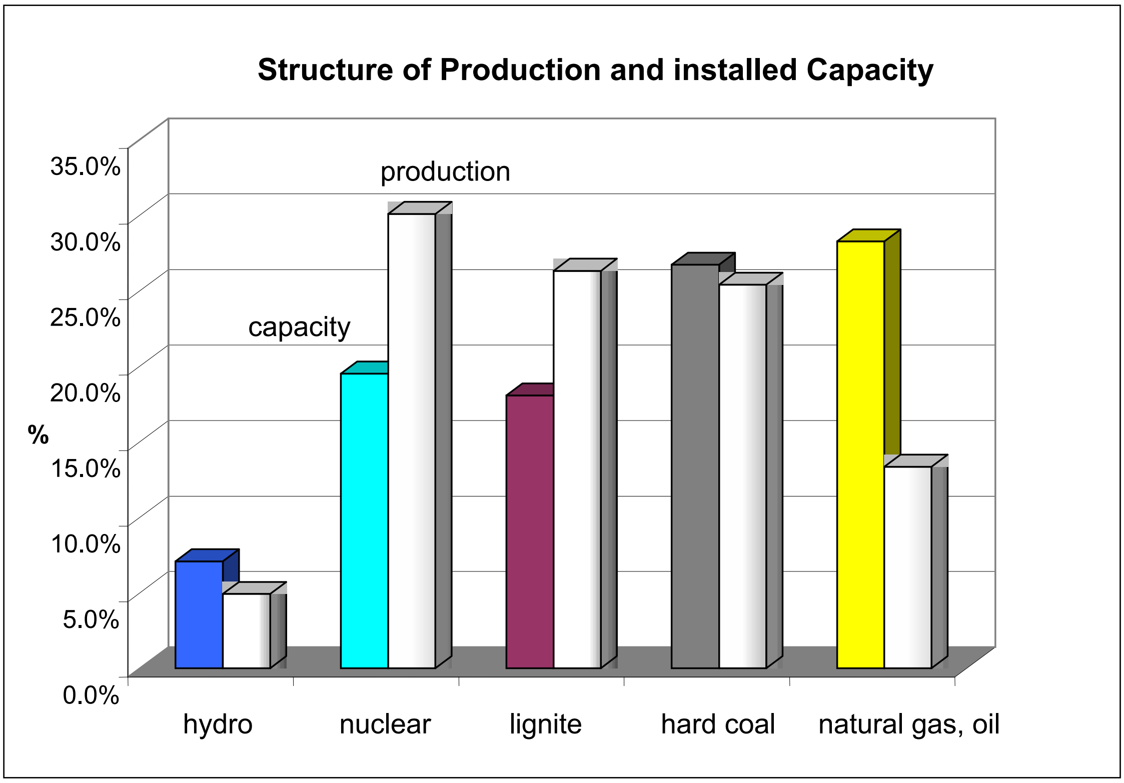

Figure 2: Structure of Energy Production and installed Capacity

[Source: bremer energie institut based on Elektrizitätswirtschaft in Deutschland (2002)]

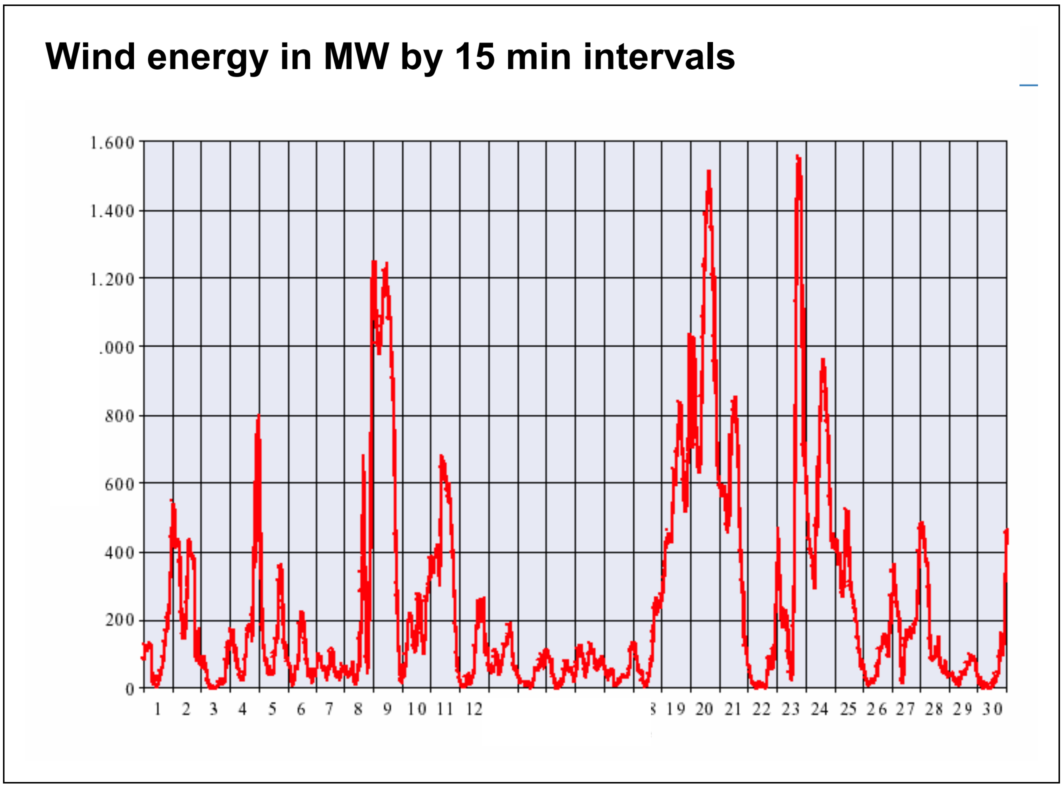

Figure 3: Wind Energy-fed into a regional Network
[Source: EWE AG]

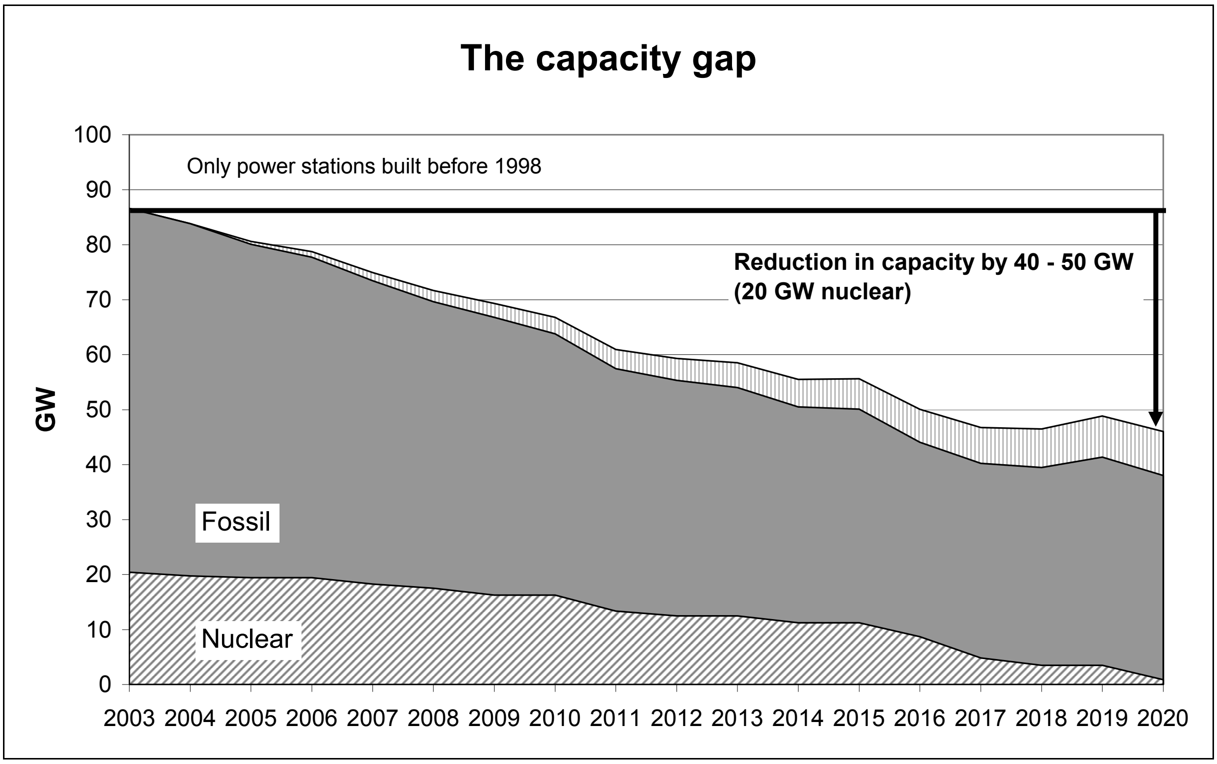

Figure 4: Capacity Gap in Germany

[Source: bremer energie institut]

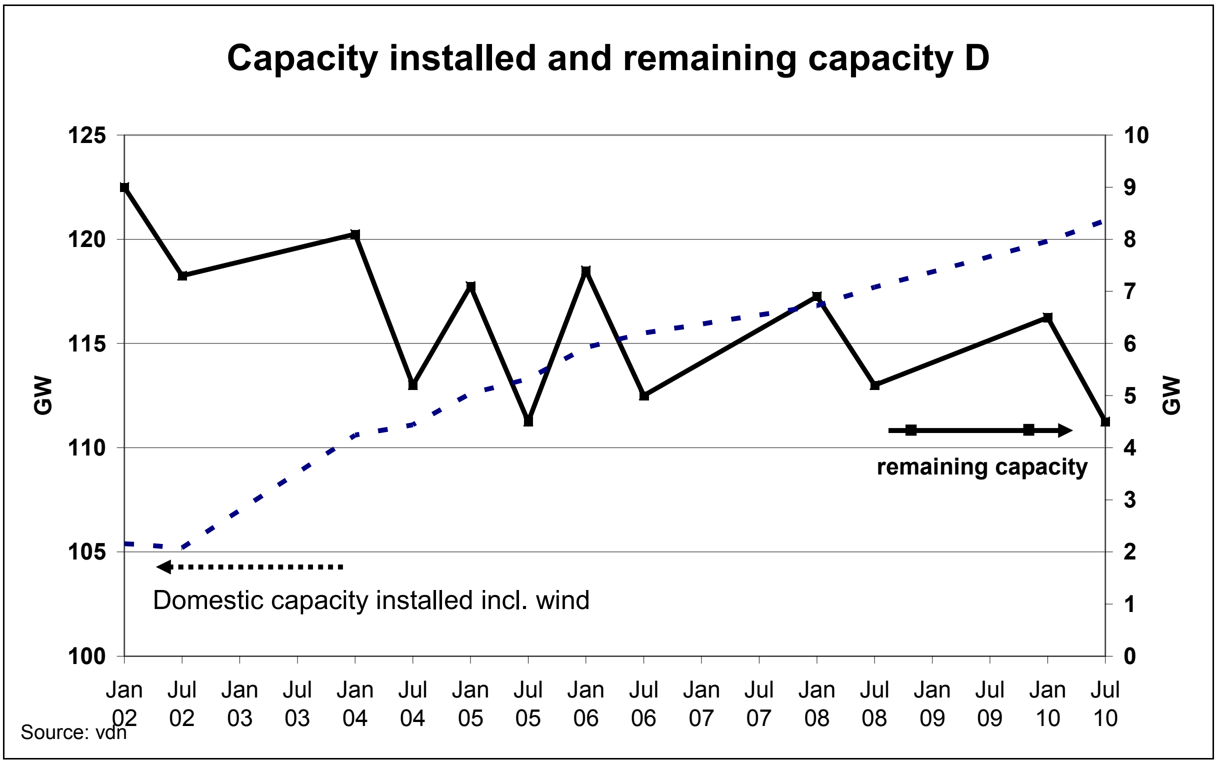

Figure 5: Capacity installed vs. remaining capacity Germany 2002 to 2010

[Source: VDN (2003)]

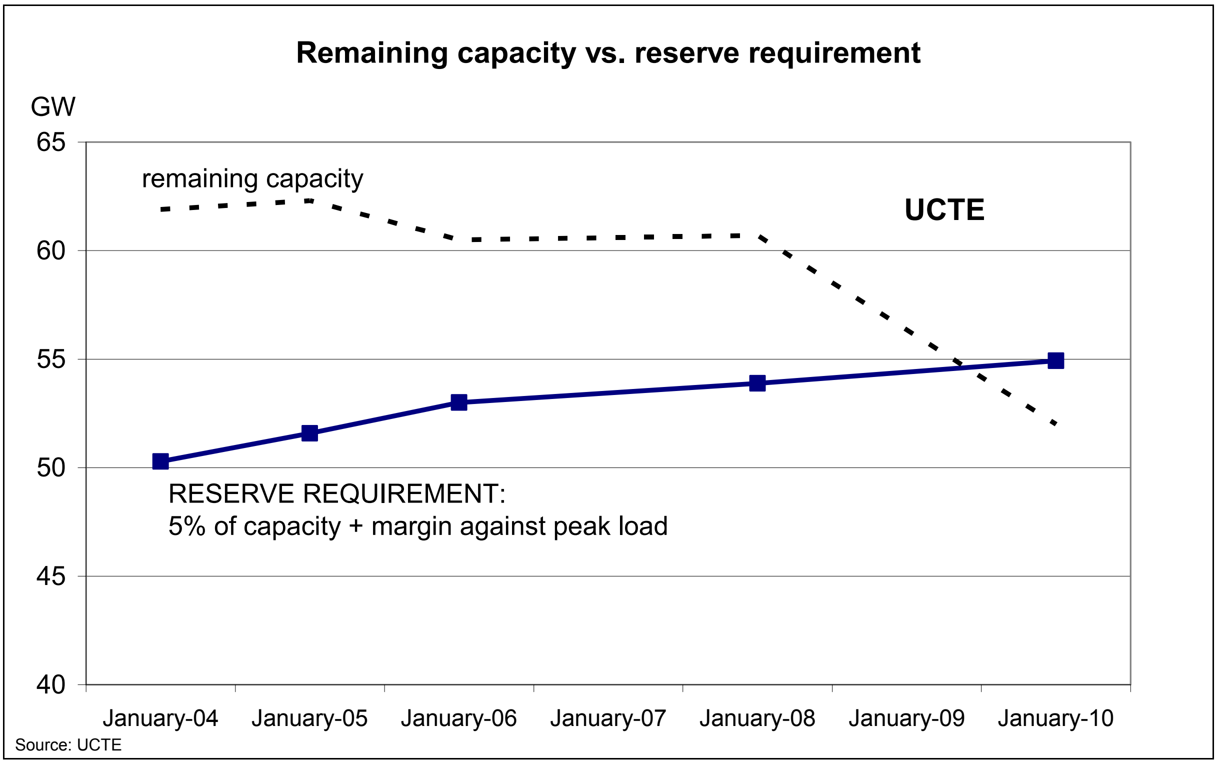

Figure 6: Capacity installed vs. remaining capacity Germany 2002 to 2010

[Source: UCTE (2003)]

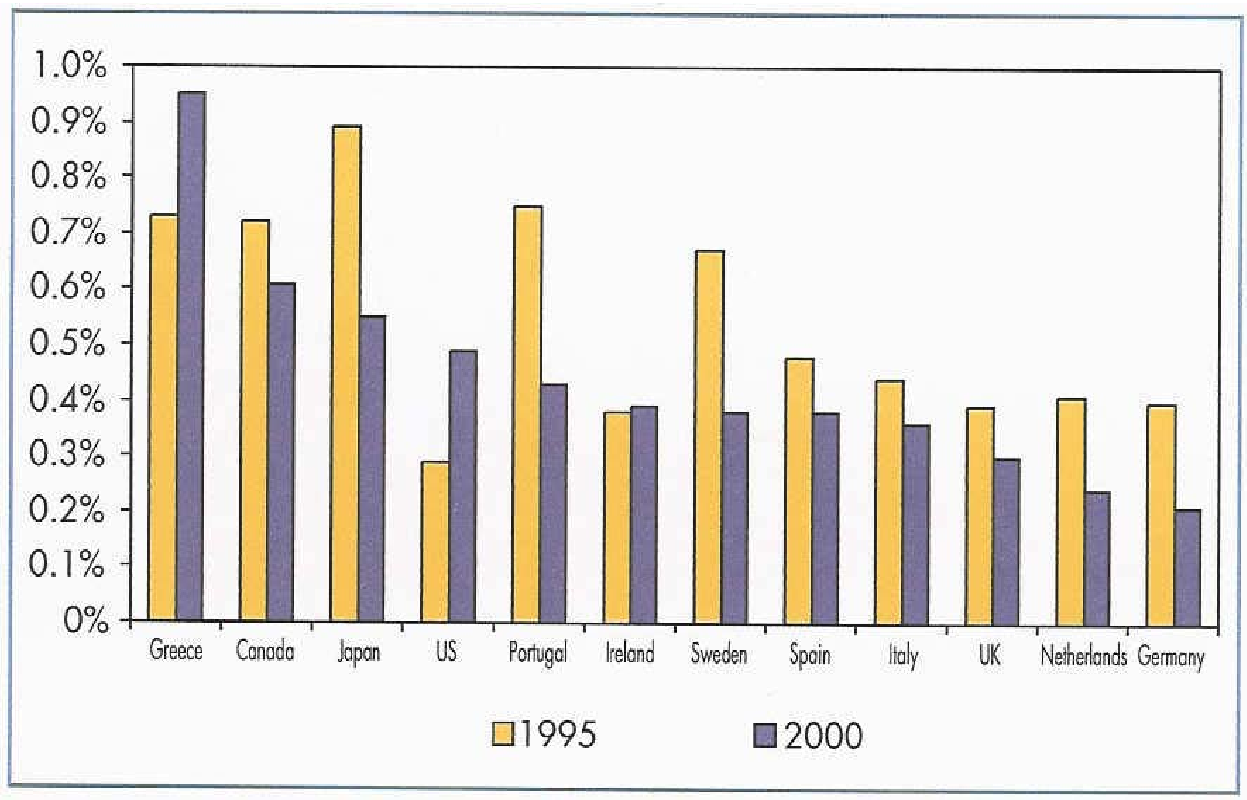

Figure 7: Share of investment in electricity sector in GDP in %

[Source: IEA (2003)]

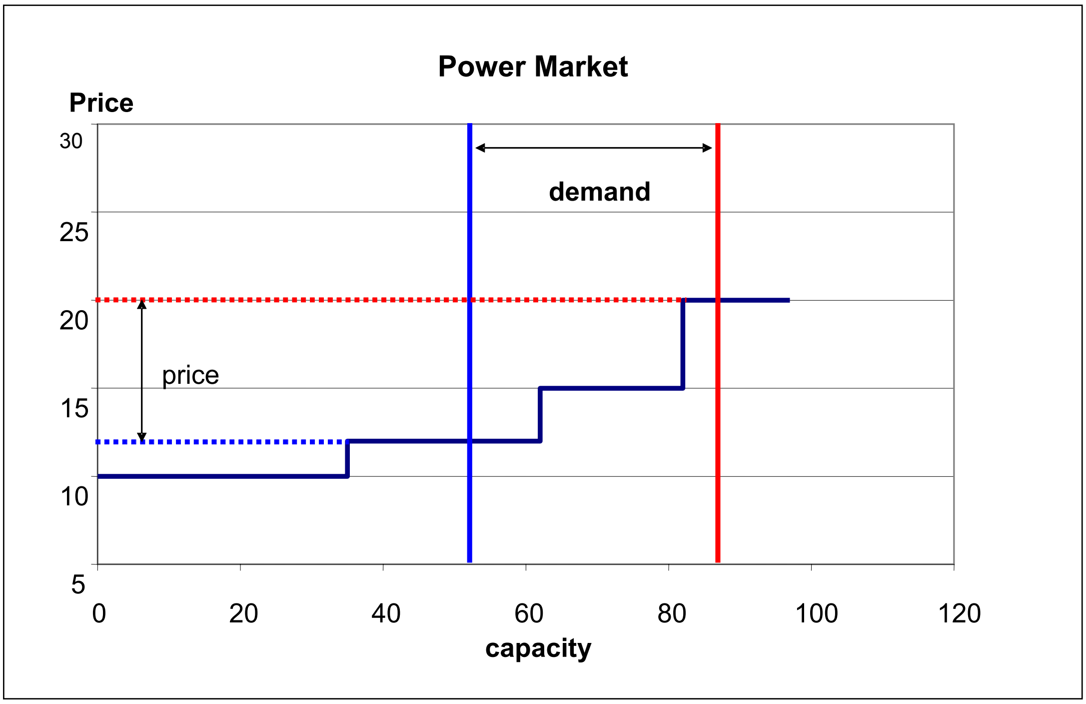

Figure 8: Price in the Market for Power

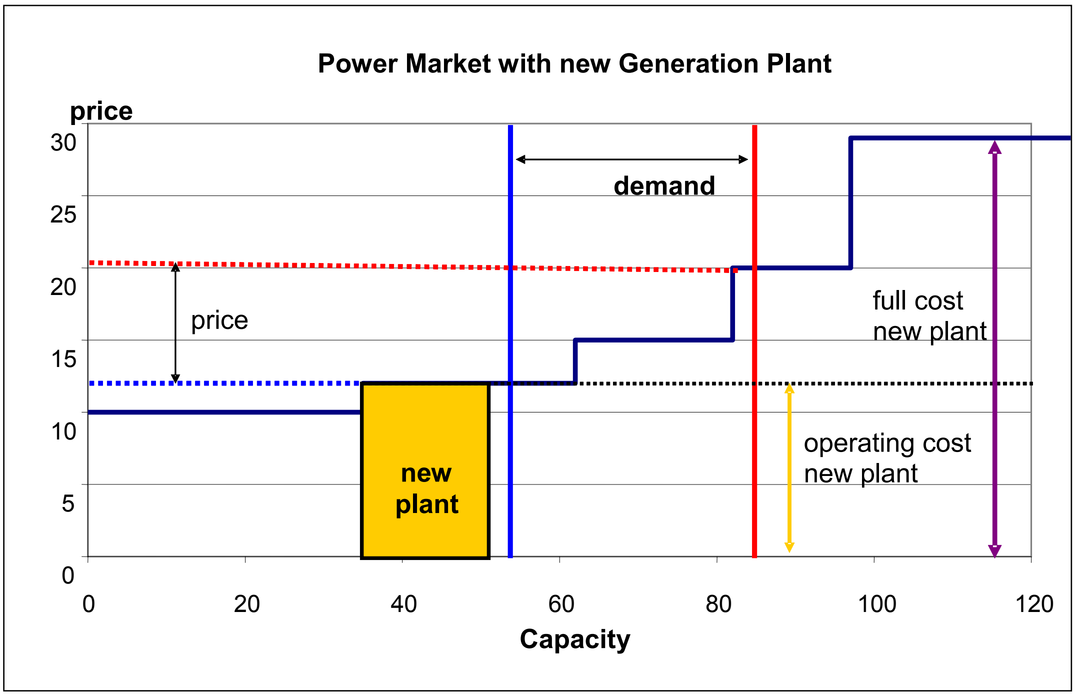

Figure 9: Power Market with new Capacity

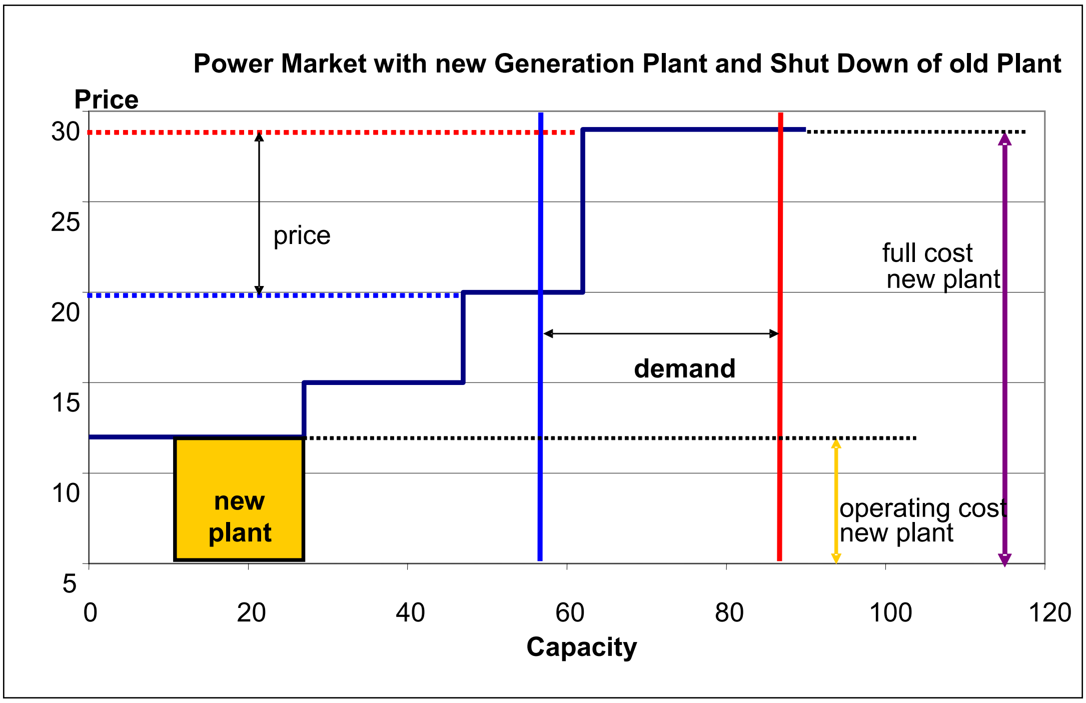

Figure 10: Power Market with new Capacity and Shut Down of old Plant

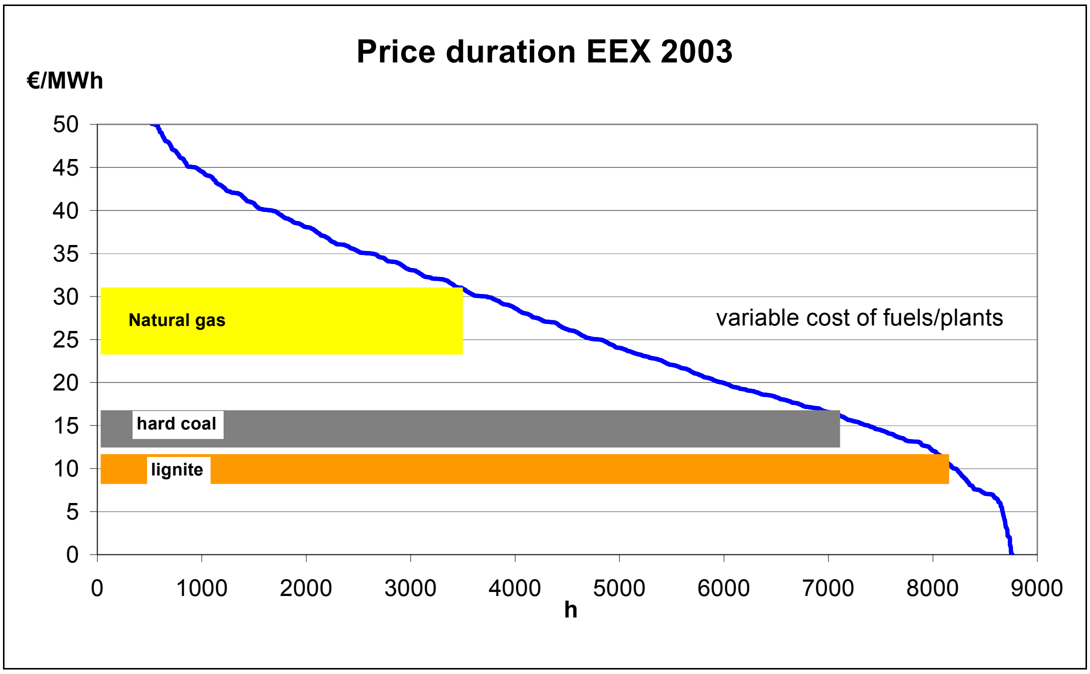

Figure 11: Price Duration Curve EEX 2003

[Source: EEX and bremer energie institut]

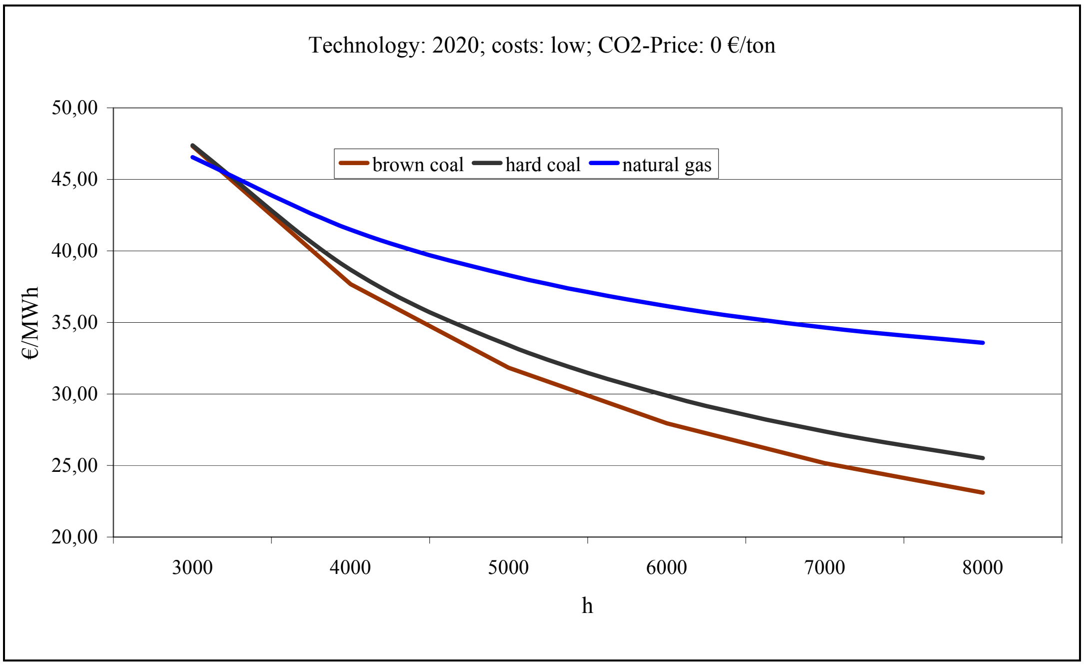

Figure 12: Cost of Electricity Production

[Source: bremer energie institut]

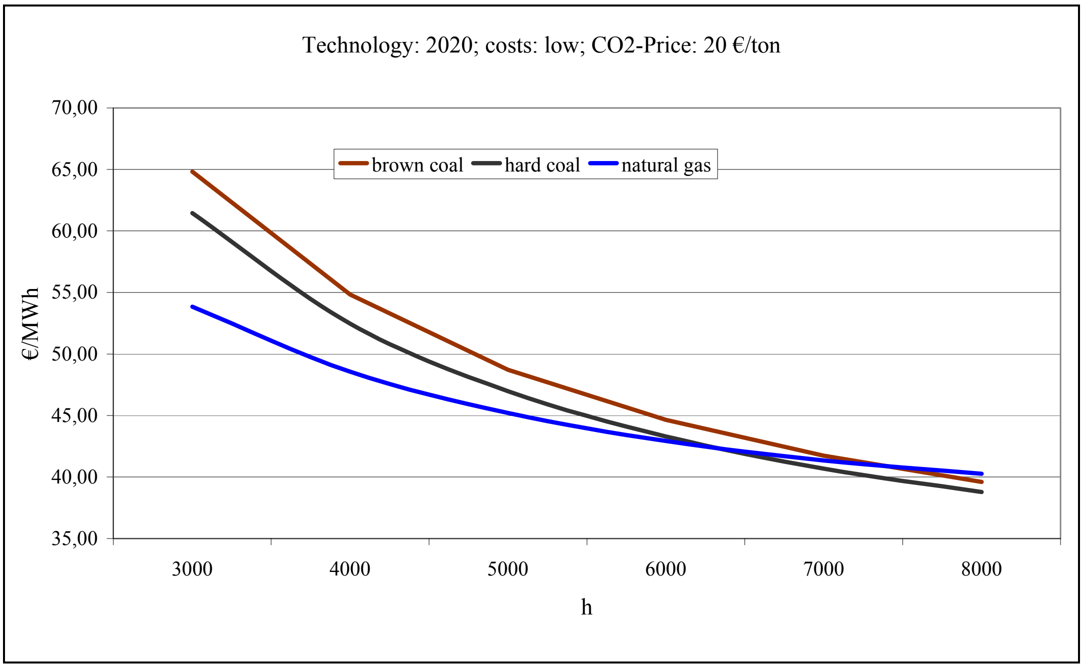

Figure 13: Cost of Electricity Production with CO_2 Price of 20 €/t

[Source: bremer energie institut]