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DISCUSSION PAPER

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The Impact of PV on the German Power Market – Or Why the Debate on PV Feed-In Tariffs Needs to be Reopened

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CONTENT

EXECUTIVE SUMMARY

During the last months, the discussion on feed-in tariffs (FiT) for photovoltaic (PV) installations in Germany has gained new momentum. On the one hand, the issue of over-subsidisation due to the fact that module prices have been decreasing faster than feed-in tariffs was discussed. On the other hand, increasing costs to the consumers of power were put on the agenda after the unprecedented increase in new PV capacity in Germany in 2009. After the general election in September 2009, this discussion lead to different proposals for adjusting the FiT scheme. On March 23, 2010 the parliamentary groups of the governing parties CDU/CSU and FDP presented a new bill. In April, the top lobbying association of the PV industry in Germany addressed Chancellor Merkel, all parliamentarians and others in full page advertisements in major newspapers to reconsider their plans.

Both, in the discussion and in the draft bill, an important aspect has been neglected so far: the impact of the massively increasing PV capacities on the economics of conventional power plants. The regulatory impact assessment of the draft bill, for example, only considers costs for the public budget, for the business sector (device manufacturers and operators as well as industrial power consumers) and for the citizens (private households). Utilities and electricity companies are not mentioned.

The present study fills this gap. In the first part, it is qualitatively shown how the power price and the equilibrium quantity on the power exchange change with increasing PV capacities. These findings can be directly translated into shrinking revenues for operators of conventional power plants. In the second part, a quantitative analysis of the German power market is provided. Based on a fundamental model analysing 8,760 hours per year with real plant data, the impact of six scenarios for the build-up of PV capacities, ranging from an immediate stop of new PV installations to an additional 50 GW of PV until 2020, are studied. The effects of different PV scenarios on the wholesale power price and the total revenues (i.e., price multiplied by quantity) of all conventional power plants are calculated. For an incumbent operator of a coal-fired power plant, the contribution margin may decrease by more than 25% and for a new, yet to build gas-fired combined cycle power plant it may drop by more than 30%. One reason for this massive impact is the fact that PV installations produce power around noon when load and, thus, power prices as well as revenues are usually the highest in Germany. In this respect PV differs considerably from other renewable energies.

The study does not make specific recommendations for policy makers, but advocates paying more attention to the so far neglected impact on the power market. It concludes that the PV support scheme can be understood as the accelerator pedal for the structural change in the German power sector. Implementing the changes in the feed-in tariffs as presented in the draft bill would require more and faster changes in the overall design of the power market to provide sufficient incentives for backup capacities when the sun is not shining. It would also be accompanied by additional acceleration costs. Absolute caps on the added capacity, rather than further cuts in the tariffs, could buy some time for a careful redesign of the market and may reduce resistance from incumbent operators.

This is all the more true since PV build-up will not stop in 2020, the year analysed in this study, but will rather continue and amplify the effects described above.

That being said, we expect the discussion on the PV feed-in tariffs to be reopened again.

1 PV IN GERMANY

Germany is perceived as a frontrunner in power production from renewable energies (RE). The structure of the support scheme is considered one of most important elements in this success story. Under the feed-in tariff (FiT) scheme (Erneuerbare-Energien-Gesetz, EEG) producers receive a fixed remuneration for each kilowatt-hour fed into the grid. The level of support depends on, among other factors, the technology, the size, the site and the age of a specific installation. The FiT rewarded to new installations is reduced every year in order to acknowledge the continuous decrease in production costs.

1.1 Important market

For a long time photovoltaics (PV) played a minor role with regard to power generation from renewable energies in Germany. However, the picture has changed significantly in recent years. For the first ten years (1990-2000) of the EEG (which was then called "Stromeinspeisegesetz"), PV capacity was negligible. As can be seen in Figure 1, in 2001 the share of PV capacity for the first time surpassed 1% of the total renewable energy capacity in Germany [BMU 2010]. Since then, PV has seen an unprecedented growth both in absolute terms and as a share of the total capacity. In 2009, PV capacity amounted to almost 9 gigawatt (9 GW = 9,000 MW) while total renewable energy capacity was 45 GW. Figure 1 shows the annual growth of PV in Germany over the last 20 years. In 2009 alone, installations of new capacity added up to 3 GW, triggering investments of almost 10 billion euros. For the last three years, annual market growth has been over 150%. Altogether, Germany is one of the most important PV markets in the world, if not the most important.

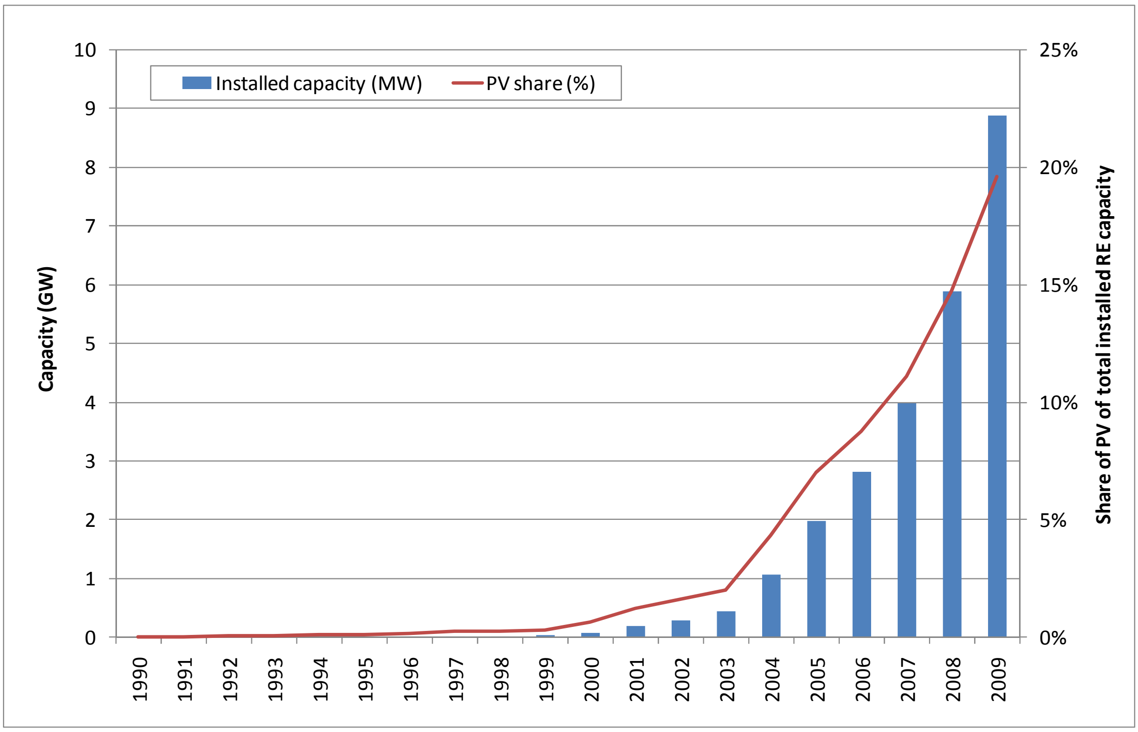

Figure 1: Development of PV Capacity in Germany [BMU 2010].

1.2 Policy discussion since 2009

Though the development was appreciated for different reasons such as environmental aspects, changing market structures (breaking the oligopoly), decentralised generation etc., recently the costs of this success have shifted into the focus of the political discussion. Two aspects need to be distinguished here:

1. over-subsidisation,
2. additional costs to the power consumers.

Even though the first aspect is related to the second, it needs to be discussed separately.

Over-subsidisation

As early as 2007, reports indicated that PV prices had started to drop faster than the feed-in tariff [RWI 2007]. It was argued that operators of large solar fields and big retail companies were exploiting the situation by buying cheaper modules while selling the complete installation at more or less unchanged prices. Thus, they generated extra profits. This was possible, since consumers would base their investment decision on the unchanged FiT. In addition, it was claimed that, since Chinese modules had become the cheapest ones, German producers were no longer benefitting from the PV capacity build-up in Germany.

Finally, since the FiT was once calculated to make PV installations possible in the areas of the lowest solar radiation and is not dependent on the geographical position, PV owners in Southern Germany, where the overall radiation is generally higher than in the rest of the country, were also accused of making unreasonable extra profits.

Consequently, researchers and the Federal Consumer Protection Association argued for cuts in the FiT of 30% or more.[1] A recent report confirms these findings [IE & ZSW 2010]. However, such cuts would mainly stop PV over-subsidisation and would, thus, have to be considered as a distributional issue. If prices really went down, growth could still continue although the more expensive (German) producers would most likely lose further market share.

Additional cost to consumers

Even if over-subsidisation was prevented by “proper” setting of the PV FiT, debate would continue on the question whether power production from PV should be supported to the current extent in the first place, since it is much more expensive than other options. This is an allocative question rather than a distributional one. The driving force behind this discussion is the fact that power consumers, who have to pay for the budget of the total FiT scheme, started to realise that their energy bills are increased due to the support of renewable energy and, more importantly, PV. Energy experts anticipated this development. The official “Lead Study Renewable Energies”, commissioned by the federal research ministry, for example, depicted the additional costs from PV in 2007 [BMU 2007, Figure 2]. What was not anticipated, however, were the dynamics of the PV market. The Lead Study 2007, for example, foresaw a total PV capacity of 4.9 GW for the end of 2010 – a figure that was already

1 See for example: “Solarsubventionen sprengen Prognosen” (Solar subsidies exceed prognoses), in: Financial Times Deutschland, 24 August 2009.

surpassed by 2008. Other studies from the same time also completely underestimated the development [EPIA 2006].

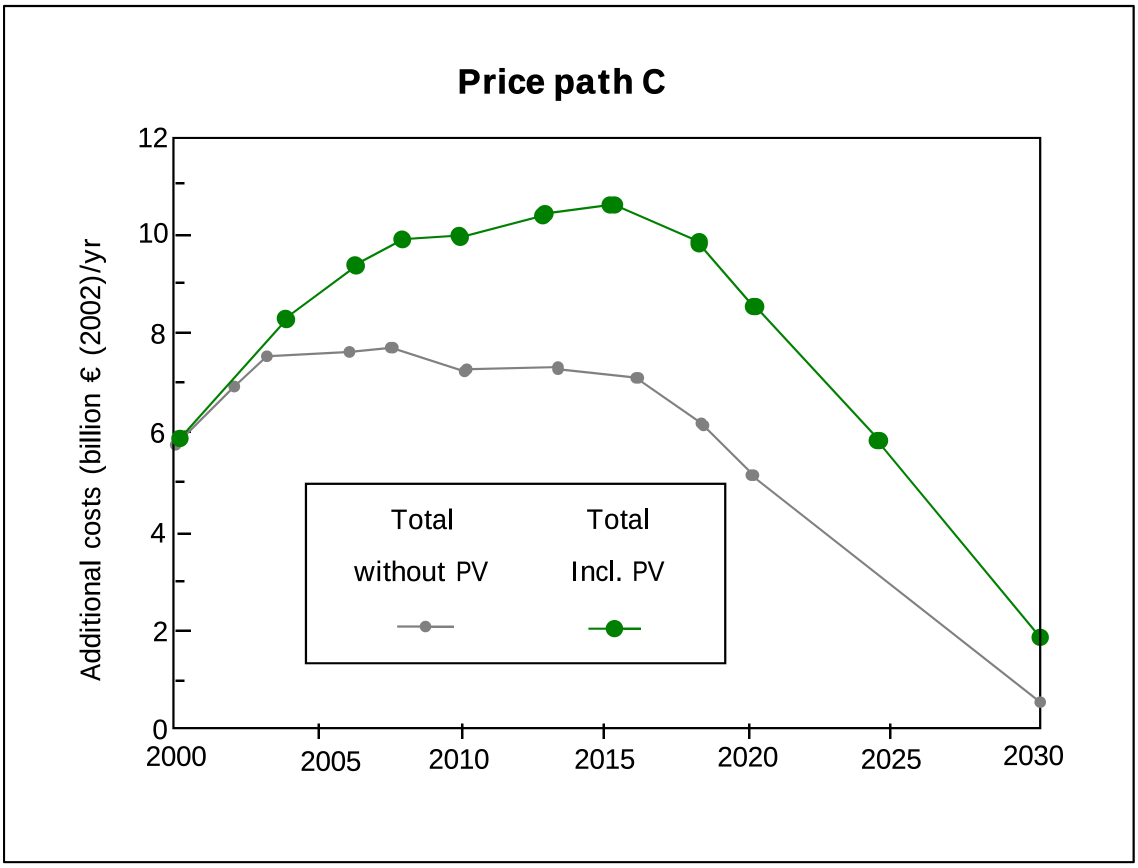

Figure 2: Anticipated additional costs from PV in 2007 [BMU 2007].

The discussion on the PV FiT gained momentum in context of the 2009 elections. Both the Christian Democrats (CDU/CSU) and the Liberals (FDP), who were expected to clearly win the elections, stated, that they wanted to adjust the PV FiT. In December 2009, the new environmental minister Norbert Röttgen (CDU) also announced for first time the need for a new kind of mechanism.[2]

The current status of the regulatory process is based on a proposal by the governing parties CDU/CSU and the Liberals that stipulates the following FiT for PV installations:

[2] See Müller and Strathmann 2009: "Röttgen setzt bei Solarstrom den Rotstift an“ (Röttgen cuts support for solar electricity), in: Handelsblatt, 11 December 2009.

Table 1: Draft PV feed-in tariffs as currently discussed (as of March 23 2010, Source: Bundestag 2010).

	Performance class and feed-in tariff in euro-cent per kilowatt-hour					
Start of operation	up to 30 kW	up to 100 kW	from 100 kW	from 1000 kW	conversion sites	other free sites
from January 1st 2010	39.14	37.23	35.23	29.37	28.43	28.43
from July 1st 2010	32.88	31.27	29.59	26.14	25.30	24.16
from January 1st 2011 (degression 11%)*	29.26	27.83	26.34	23.26	22.52	21.50

*) 11% degression is the sum of the general degression of 9% plus an extra degression as a function of performance class (here: 2%).

The draft bill explicitly mentions a desired target for the annual increase of PV of about 3 GW. This will be supported by a corridor between 2.5 and 3.5 GW for which there is no additional cut (degression) in feed-in tariff if the new capacity in the previous year is within this corridor. If the new capacity is below 2.5 GW then scheduled cuts will be reduced by 2.5 percentage points for each 500 MW below the target. If, however, the new capacity exceeds 3.5 GW additional cuts will apply. For each 1,000 MW above the upper target the degression will increase by 2 percentage points in 2011 and by 3 percentage points in 2012. An upper threshold is set at 6.5 GW. Thus, for example, the maximum additional cuts will be 8% in 2011 if PV capacity increases by 6.5 GW or more in 2010.[3] Whether investments in new PV devices are economically attractive, thus, strongly depends on the cumulative new capacity in the previous year and the development of the module costs. Therefore, the exact new PV capacity for the years to come cannot be derived from the proposed regulation.

In addition, it has to be mentioned that there is a loophole in the current proposal. If the power produced is consumed by the producer himself, different rules apply that are much more attractive. The threshold for self-supply is increased from 30 kW to 800 kW installations.

Still, the final decision has not been made yet. The solar industry seems to have been successful in lobbying for a new discussion. Both timing and size of the cuts are under negotiation again. The issue now regularly enters even newspapers and TV-documentaries. The impact of additional costs arising from the FiT on poorer people like retired persons or single mothers and fathers is focused on by the news coverage.

Interestingly enough, the discussion has so far neglected one important fact: The impact of PV on the power market.

[3] The exact calculation depends on a reference period between June 1 and September 30.

2 THE IMPACT OF PV ON LIBERALISED POWER MARKETS

The liberalisation of energy markets in Europe was initiated at the end of the last century by the EU directive concerning the internal market in electricity.[4] There were many motivating factors; Paragraph 4 of the directive provides an overview:

> *"Whereas establishment of the internal market in electricity is particularly important in order to increase efficiency in the production, transmission and distribution of this product, while reinforcing security of supply and the competitiveness of the European economy and respecting environmental protection (...)."*

As can be seen, various objectives were considered, that potentially contradict each other. At least with regard to efficiency, the Commission concludes that liberalisation has been successful:[5]

> *"By opening up these markets to international competition, consumers can now choose from a number of alternative service providers and products. Opening up these markets to competition has also allowed consumers to benefit from lower prices and new services which are usually more efficient and consumer-friendly than before. This helps to make our economy more competitive."*

The initial decrease in prices was mainly due to the fact that in the context of liberalisation the former regional monopolies were dismissed. As customers were now able to choose their supplier, the latter had to adopt their pricing strategy to the rules of competitive markets, i.e. most importantly to offer electricity at marginal costs of production. In part, however, the price decrease was triggered by the expansion of electricity production from renewable energies. This will be demonstrated in more detail below, after the principle functioning of the market has been explained.

2.1 The functioning of liberalised power markets

Before discussing the effect of increasing PV capacities on prices and revenues, it is important to fully understand the functioning of liberalised power markets. Most importantly, the difference of *total average costs* (that also form the basis for FiTs) and *marginal costs* needs to be fully understood.

2.1.1 Total average costs of electricity production

The total average electricity production costs of a power plant consist of a variable part, which is (typically) proportional to the quantity of electricity produced, and of a fixed part, which exists whether or not the plant is generating electricity. In order to simplify the analysis, it is assumed that there are only three cost factors for the production of electricity:

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[4] Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity, OJ 1996 L 027.

[5] DG Com, "Competition policy and the consumer", 2004, available on the Internet at: ec.europa.eu/competition/publications/consumer_en.pdf (last accessed on 7 May 2009).

- capital costs,
- fuel costs, and
- environmental costs in the form of CO_2 emission allowances.

Capital costs are typically fixed costs whereas the other two categories represent variable costs. According to experience, other expenses such as fixed and variable operating and maintenance costs are small compared to the three aforementioned factors and are, thus, not considered for the basic analysis here (cf. Figure 3).

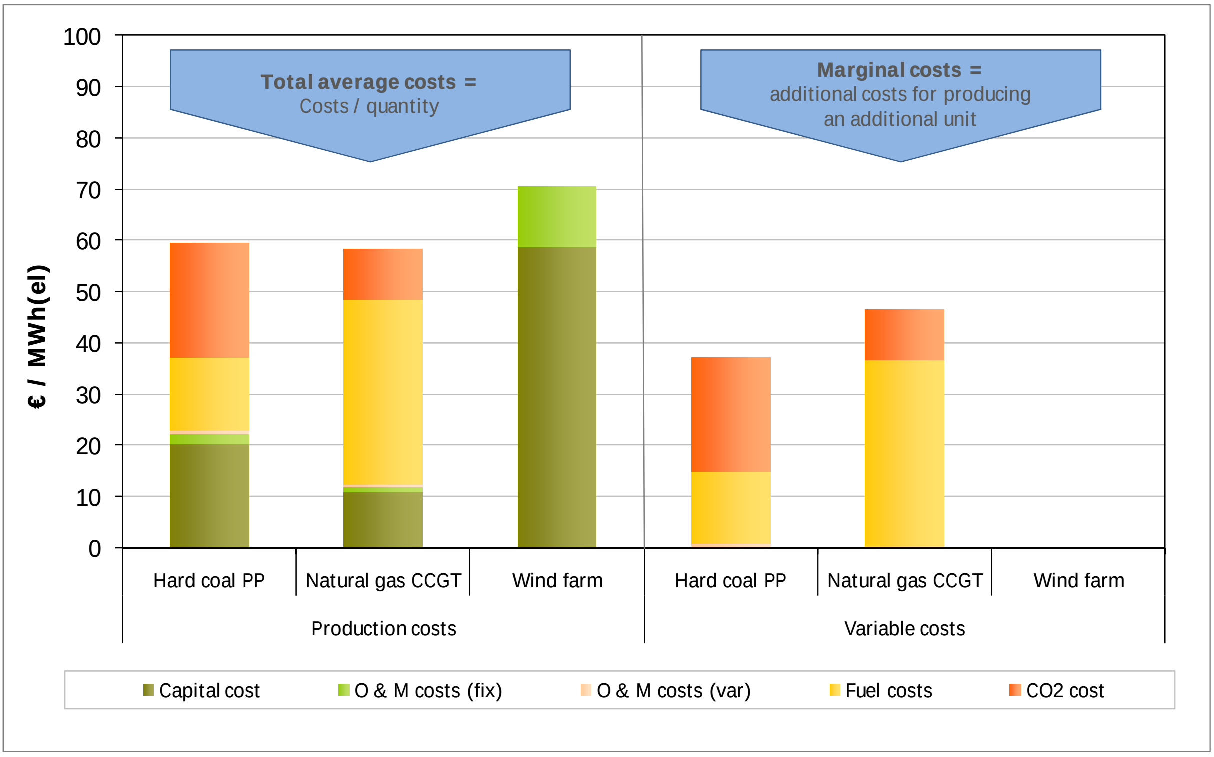

Figure 3: Electricity production costs of various power plants (schematic representation).

To be able to add the variable and fixed costs of the electricity production in euros per megawatt-hour (€/MWh), the fixed costs must be related to the amount of electricity generated. Therefore, the total investment sum for the power installation is distributed across the individual years of the targeted amortisation period using the annuity method. Dividing the so derived annual fixed costs of the investment by the corresponding electricity production, yields the specific capital costs of the power plant. They strongly depend on the amount of electricity that is produced. Fuel and CO_2 costs are, in contrast, variable and proportional to the amount of electricity produced. They depend on the fuel price, the efficiency of the power plant, the specific CO_2 emissions of the fuel, and the CO_2 price (see Figure 3).

2.1.2 Static analysis of production quantity, electricity price, and revenues

The revenue of a power plant is the product of the electricity quantity sold in one hour and the electricity price for this hour. As we will see, whether or not an individual power plant will be among those producing electricity depends on the market price. Consequently, not only the price, but also the quantity of electricity, which is produced and sold during its economic serviceable life, is important for the investment calculation. In the following, it is assumed that perfect competition prevails. This market form is also the objective of the European Commission in order *"... to make sure that companies compete with each other and, in order to sell their products, innovate and offer good prices to consumers."* [6] According to cost theory, in such a competitive market producers offer goods at the marginal costs of production, that is, the costs that are incurred with the production of an additional unit of their product. Capital costs are no longer relevant in this case. For power plants, the marginal costs primarily result from the sum of the specific fuel costs and the specific CO_2 costs (see Figure 3).

In order to describe the pricing on the power exchange, only the so-called spot market will be considered in the following.[7] This is the closest to the actual physical activity. The intersection of the aggregated supply with the total demand curve results in an equilibrium price for each hour of the day. The product of this price and the demand represents the revenues for the power plants in operation (see Figure 4). These revenues have to cover the marginal costs and – in order to be economically viable in the long-term – the capital costs. Only when the revenues exceed the sum of costs, can profits be earned. The aggregated supply curve, which consists of the individual supply curves of the specific power plants, is also referred to as *merit-order curve* in energy economics.

Figure 4 shows the price finding mechanism for one individual hour. However, both, the merit-order as well as the demand curve undergo constant change on different time scales. Thus, calculations have to be carried out on an hourly basis rather than using annual averages for prices and quantities. The timing of the electricity production is important as electricity can only be stored on a small scale at high costs and must, thus, in general be utilised immediately.

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6 Jonathan Todd, Commission competition spokesperson; transcript from an interview on BBC World, September 2007, Source: ec.europa.eu/competition/consumers/index_en.html. More information on EU competition policy is also available on this site.

7 In addition to the spot market, there is also the forward market, at which standardised products are traded, i.e. a defined amount of power over a fixed time period (year, quarter, month). However, prices at these markets are always based on expectations of future spot market prices.

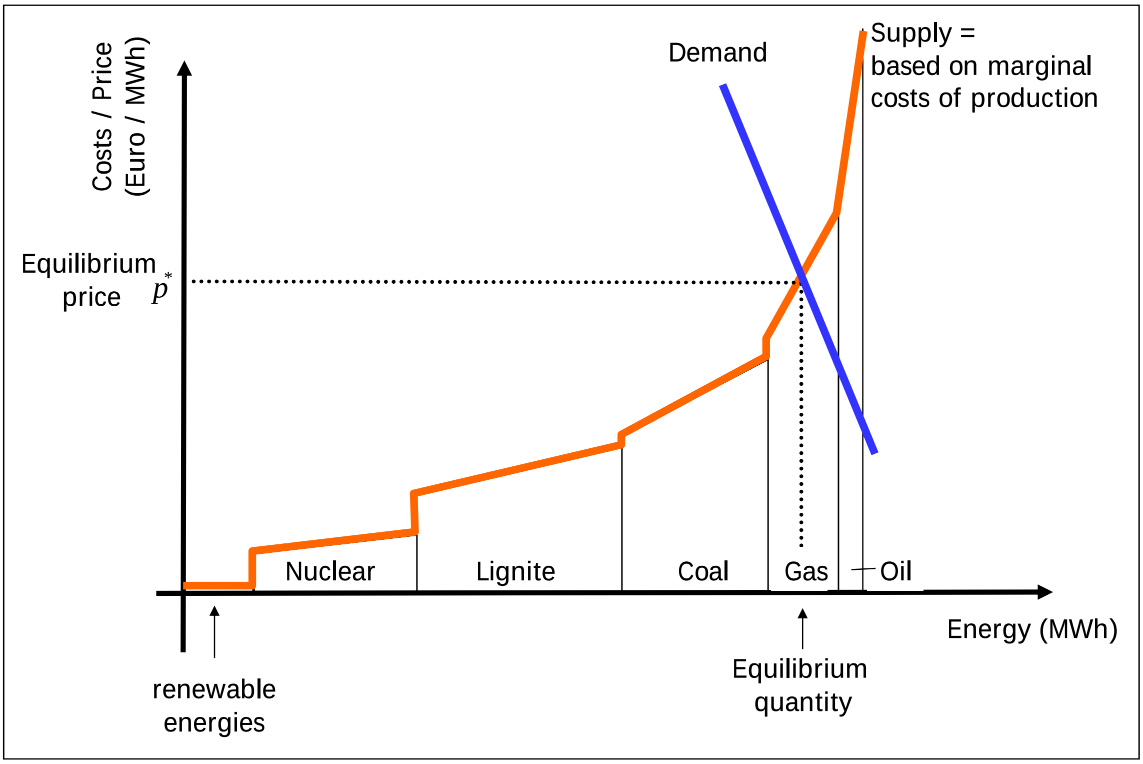

Figure 4: Pricing on the electricity exchange in one hour.

In such a market setting, it is difficult to create incentives for investments in new power plants since the relatively high capital costs are difficult to recover with revenues based on marginal costs of production plus technical limitations for new entrants to reduce their marginal costs [for more detail see Bode & Groscurth 2009a+b]. Attention was called to this problem several years ago [Weber 2002, BCG 2003]. Up until now, the issue has not entered the public energy policy debate in a meaningful way. Nevertheless, it is of utmost relevance for the future electricity supply and it is significantly exacerbated by the rapid build-up of PV capacity.

2.1.3 Dynamic analysis of production quantity, electricity price and revenues

The analysis in the previous section was static in the sense that it showed an individual hour with a fixed demand and a given mix of available power plants. Obviously, both these characteristics fluctuate on different time scales.

Electricity demand is varying both over the day and over the year. Demand is generally lowest in the night and has typically two peaks during daytime, one at noon and another one in the late afternoon. In Germany, demand tends to be higher in winter and lower in summer. Consequently, prices on the power exchange are constantly moving up and down over the day and over the year. This mechanism is shown in the form of monthly averages for a 24-hour period in Figure 5. If the load is low, the demand curve intersects the supply curve more to the left hand side, and the respective equilibrium price is rather low. As load increases (over the day) the point of intersection moves to the right. As a consequence, the price increases. It is important to remember at this point, that for each hour there is only one market price for all plants. This single price for an hour equals the revenue per kilowatt-hour for each plant producing. Thus, the revenue changes in line with the load. The difference between the equilibrium price and the marginal cost of production equals the contribution margin of an individual power plant for that hour. If load and prices change over the day the contribution margin must change over the day, too (see Figure 6). The total contribution margin for a year has to be calculated based on the 8,760 individual margins for each hour of a year. Multiplying the average annual wholesale power price by the amount of electricity produced over the year may be grossly misleading.

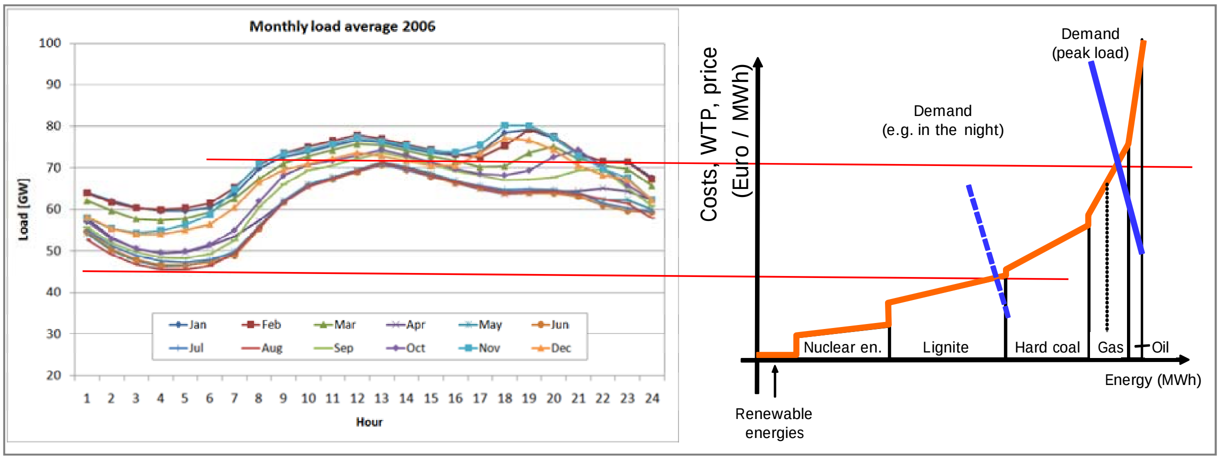

Figure 5: Load curves and derived power prices at different hours of a day (schematic representation).

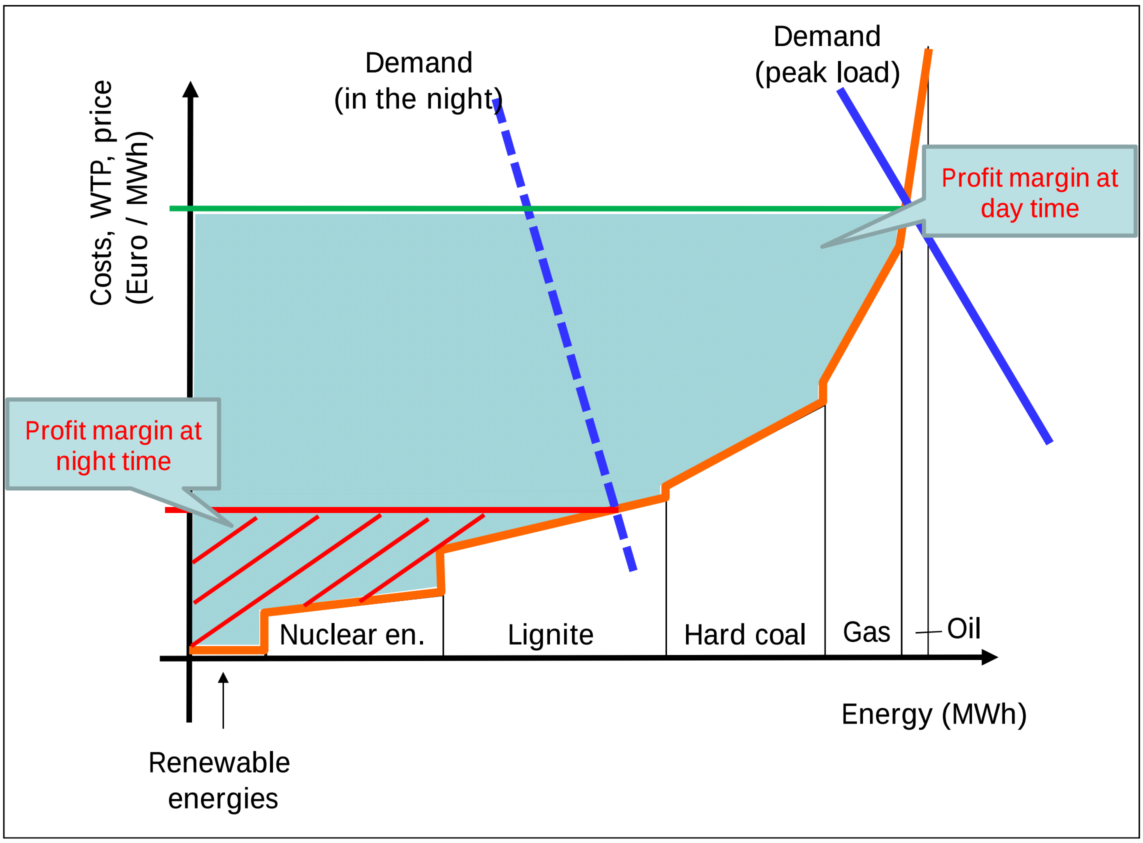

Figure 6: Contribution margin at different hours of the day.

While Figure 6 showed the formation of prices over a single day, the relative distribution of load over the year is presented in Figure 7. As discussed earlier, prices are generally high when the load is high (red cells) and are low when the load is low (green cells). The red oval schematically shows where PV is producing (see also Figure 8).

Hour of a day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	64	64	62	58	54	55	55	53	56	57	58	58
2	62	62	60	53	50	50	51	49	52	53	55	55
3	60	60	58	51	48	48	49	47	50	51	54	54
4	60	60	57	49	46	47	48	46	48	50	[illegible]	54
5	60	60	58	50	46	47	47	46	48	50	[illegible]	55
6	60	61	59	51	48	47	48	46	49	51	[illegible]	56
7	64	65	63	53	50	49	50	49	53	55	65	60
8	70	71	67	57	56	55	56	56	61	62	71	67
9	73	74	71	62	62	62	62	62	66	68	73	70
10	74	75	73	65	66	66	66	66	69	71	74	71
11	75	77	74	67	68	67	68	67	71	72	76	72
12	77	78	76	69	69	69	69	69	72	73	77	74
13	76	77	75	71	71	71	71	71	74	74	76	73
14	75	76	74	70	70	69	70	70	72	73	75	72
15	74	74	73	68	69	68	68	68	71	71	74	70
16	73	73	72	66	67	66	67	67	69	70	74	71
17	74	72	70	65	66	65	66	65	68	69	76	73
18	78	75	70	64	64	64	65	64	67	68	80	77
19	79	79	74	64	64	64	65	64	67	69	80	77
20	77	78	75	64	65	64	65	64	68	73	77	74
21	73	74	72	64	64	63	64	64	69	74	73	71
22	71	72	70	65	62	61	61	62	70	70	70	68
23	71	71	70	64	62	60	60	61	65	66	68	67
24	68	67	66	62	60	59	60	58	61	62	62	62

PV produces here

Figure 7: Average daily load curves for different month (load in MW).

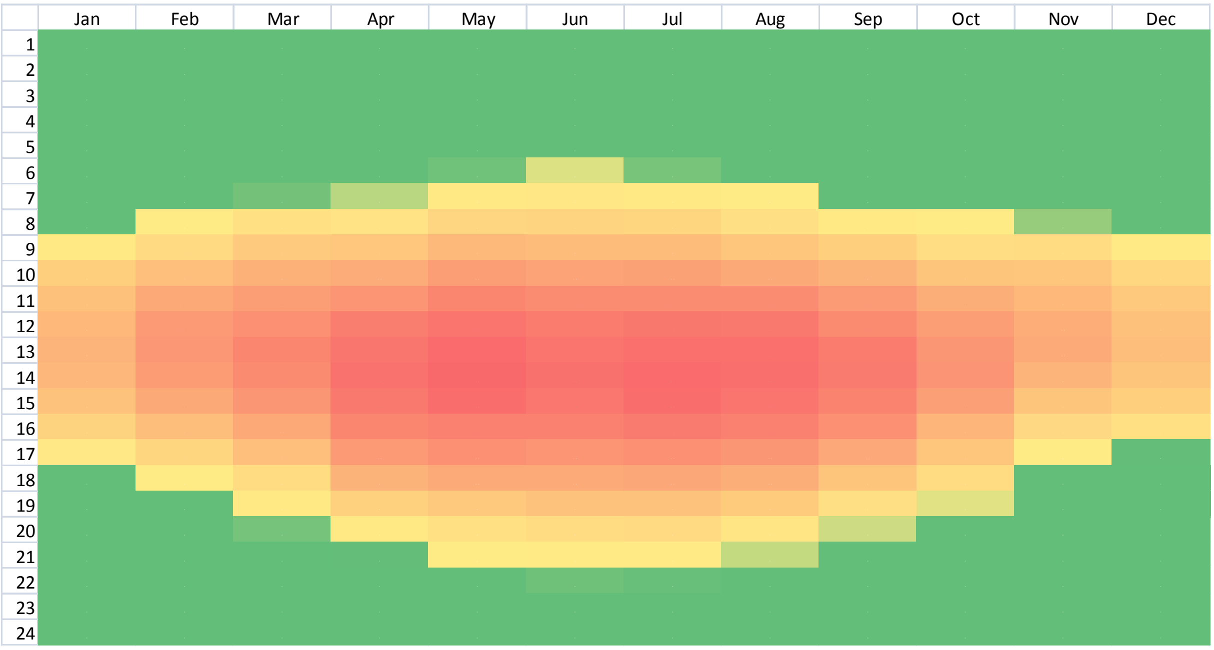

Figure 8: Power production from PV over the day and over the year (green = minimum (zero); red = maximum (depending on installed capacity), based on average figures.

2.2 The impact of additional PV capacity on power prices

After discussing the formation of the equilibrium price on a power exchange and the resulting contribution margin, the following section describes the effect of a changing supply curve, namely the introduction of new capacities.

2.2.1 Qualitative impact of new production capacities on wholesale power prices

If additional electricity from renewable energies enters the market, for example, due to investment triggered by a FiT, the supply curve in Figure 9 is shifted to the right. This is especially true for PV and wind energy, which play the most important role among all renewable energies, at least in Germany. Since their marginal costs of production are almost zero, they align at the left end of the merit-order curve.

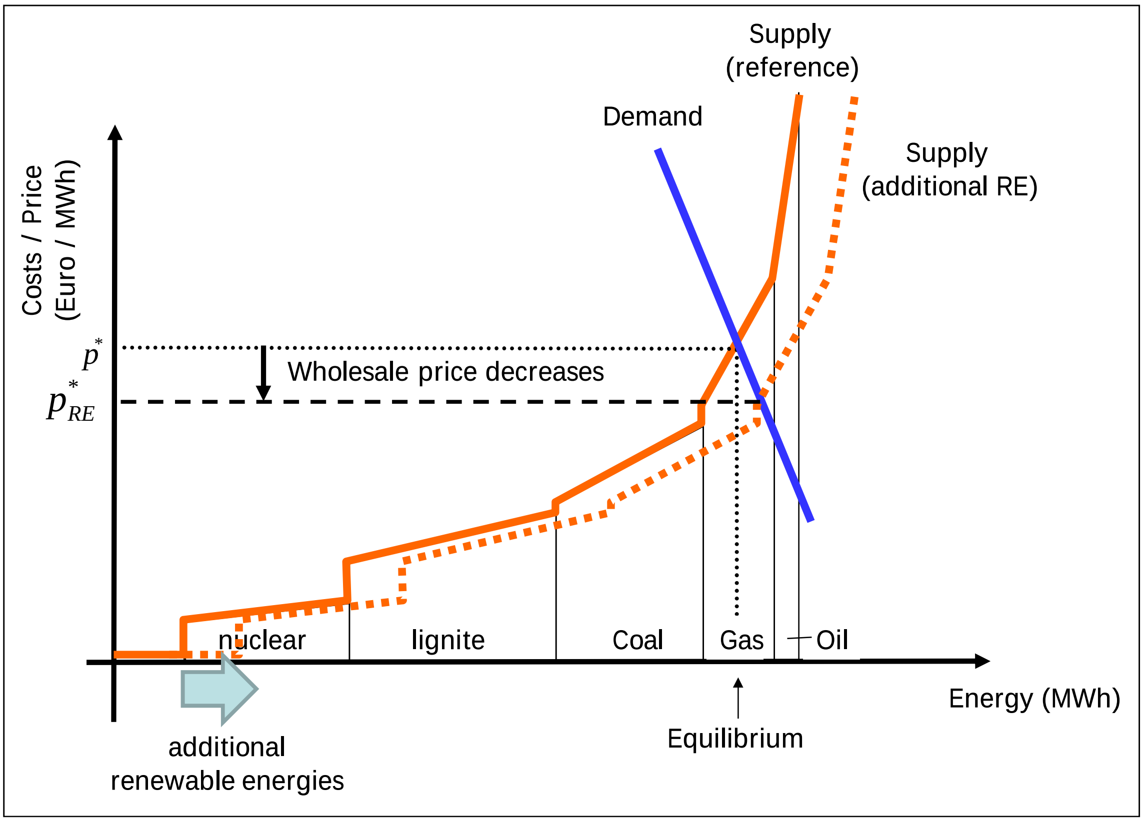

Figure 9: Effect of additional RE capacities on equilibrium prices.

As a consequence, the equilibrium price decreases. This was first described by Bode & Groscurth in 2006. In the following, this so-called merit-order effect has been repeatedly cited and analysed, because a decrease in wholesale power prices may lead to a reduction of consumers' energy bills. Until that point, it had been argued that the support of renewable energies through a FiT scheme always leads to higher costs for the consumers as, at the end of the day, the additional costs of production from renewable energy installations need to be financed. To determine, which of the two effects predominates, one has to compare the renewable energy mark-up paid by the consumers with the reduced wholesale power price. For the past, it has been shown that the overall price effect may indeed be negative [Bode &

Groscurth 2006, Sensfuß et al. 2008, de Meira et al. 2008 for Spain]. However, at least for Germany, one has to acknowledge that there are so many different rules and exemptions governing the mark-up (e.g. hardship clauses), that a general assessment is difficult.

It is important to note, that the effect on the wholesale price is not technology specific whereas the additional costs from the support scheme do depend on the technology (see Figure 10). In other words, the merit-order effect can be diluted or strengthened by the choice of technology.

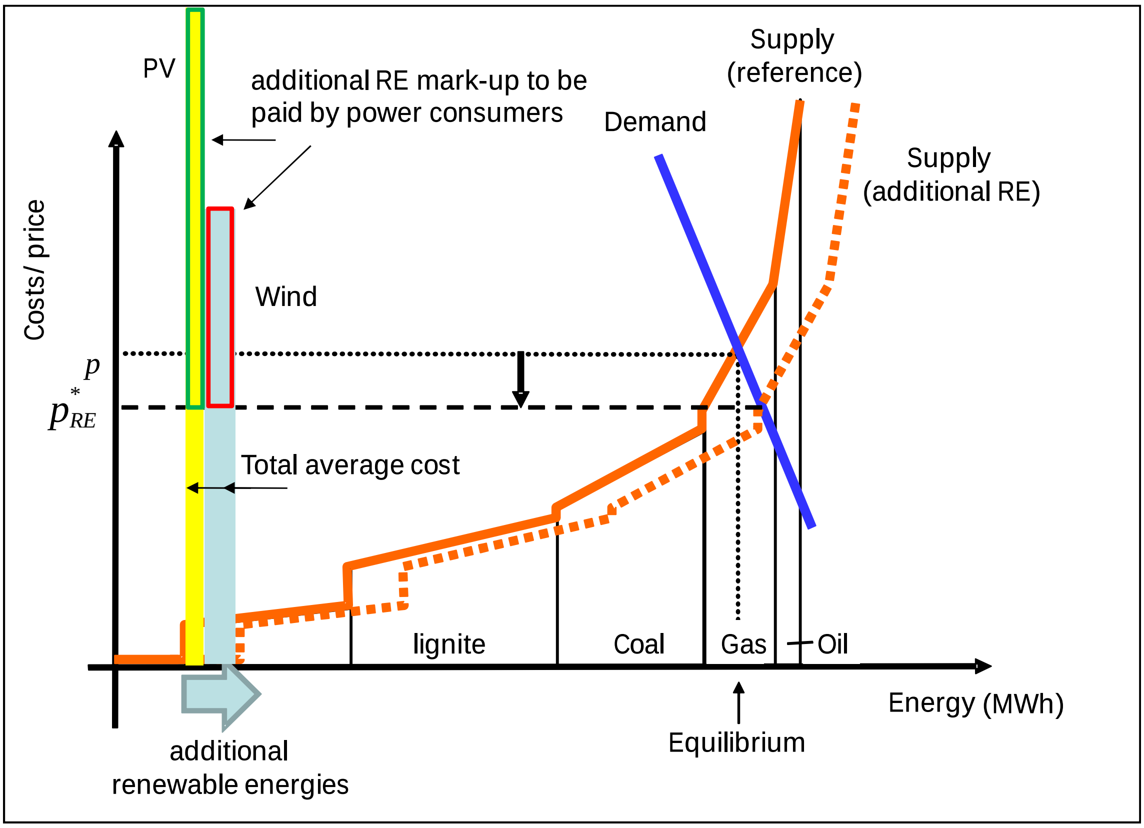

Figure 10: Power prices and RE mark-up under German FiT.

2.2.2 Qualitative impact on revenues of conventional plants

As shown in Sec. 2.1, power prices change over the day – and so does the production from PV devices. On average, their production peaks around noon and is inevitably zero during the night. Given that production from PV peaks at noon, the reduction of wholesale price will be the largest at noon, too. As has also been shown above, contribution margins are highest at noon, both in relative terms (i.e. in €/kWh) and in absolute terms (i.e. in (€/kWh)*kWh = €). The effect is shown as price difference Delta 1 in Figure 11. Due to the price reduction caused by PV at noon, market turnover is reduced significantly. Consequently, the revenues of conventional plants are diminished significantly by the simultaneous reduction of market price and remaining demand around noon. The price effect is smaller during the night time (cf. price difference Delta 2 in Figure 11). Consequently, market turnover and profitability of conventional plants are likely to be less affected by wind turbines compared to PV devices as the former have a more constant diurnal production profile.

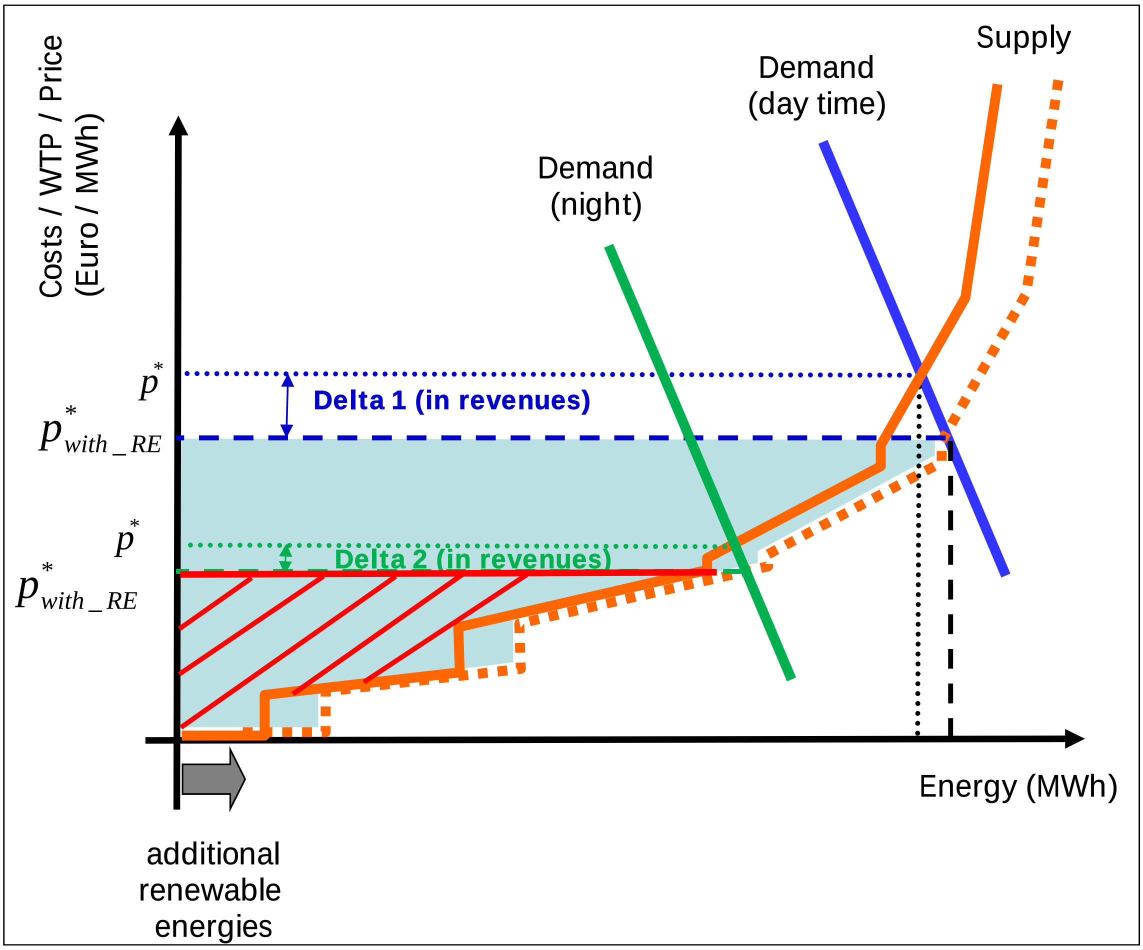

Figure 11: Changes of prices (and contribution margin) at different hours of a day.

2.3 Quantitative analysis of different scenarios for the PV development

In this section, we provide a quantitative analysis of the German power market with respect to different paths for the PV capacity build-up.

2.3.1 The electricity market model

The analysis is carried out using a fundamental electricity market model that calculates equilibrium quantity and price for each of the 8,760 hours of a year. The target year is 2020. For the sake of simplicity, the total electricity demand is assumed to be constant at 565 TWh per year as one may find arguments for both a decrease in total consumption caused, e.g. by improved energy efficiency, or an increase triggered, e.g. by e-mobility. The shape of the load curves is assumed to be the same as in 2006. Potential effects from smart metering etc. will probably still be small in 2020 and are, thus, not considered. On the supply side, all major power plants in Germany are taken into account. The life time for existing plants is set according to DENA 2010. Information on other parameters such as fuel prices is provided in the annex. Nuclear phase out in Germany is, for the moment, considered as foreseen by the existing law. Thus, by 2020, almost all nuclear plants will have gone off-line. New capacity for lignite and coal fired power plants is limited to those plants whose construction has already begun [see BUND 2010]. Planned plants are disregarded as many projects have lately been given up. In order to allow for a secure supply at any time, additional new capacities of gas turbines and gas-fired combined cycle power plants are foreseen. (In anticipation of the results, it remains to be seen if any private investor will be willing to build such new capacity). These capacities are constant and not dependent on the PV capacities: Residual load needs to be satisfied in all hours, i.e. also when PV is not producing as, for example, at night or in the winter time. Non-PV renewable capacities are set as in the BMU Lead Study [BMU 2009]. The following scenarios for PV capacities in 2020 are considered:

Table 2: Status and scenarios of possible developments of the PV capacity in Germany.

PV capacity as of Jan 1st 2010 (GW)	**Additional capacity by Jan. 1st 2020** compared to Jan. 1st 2010 (GW)	**Total PV capacity as of Jan. 1st 2020** (GW)	**Rationale for the scenario**
~ 9.0 ***)	0	9.0	“Emergency braking”
	5.0	14.0	Spanish case (0.5 GW per year)
	14.3 *)	23.2	BMU Lead Study 2009
	31.5	39.5	BEE Road Map 2010
	33.0 **)	42.0	PV Bill (draft) March 23, 2010
	50.0	59.0	Business-as-usual (BAU): costs reduction for PV faster than FiT adjustment

*) Figure provided for December 31, 2020
**) Figure presumable provided for December 31, 2020 (11 yrs à 3 GW)
***) Source: BMU 2010

As an extreme scenario, the immediate stop of all PV support is considered (“Emergency breaking”). This is more done to support estimating the size of the quantitative effects rather than being a realistic policy perspective. The second scenario is a cap on the added PV capacity of 0.5 GW per year as is already in place in Spain. Third, there is the path foreseen by the BMU Lead Study [BMU 2009]. Fourth, the more ambitious road map outlined by the renewable industry association BEE is taken into account [BEE 2010]. The current draft of the new FiT scheme for PV would allow for an even higher PV capacity in 2020 and at the same time gives an estimate of what is to be expected if the FiT remains unchanged (“BAU”).

2.3.2 Results

The impact of the different PV capacities on the power market can be described in two steps. First, the change of the residual load that needs to be met by conventional sources can be determined. This gives a general idea of the effect from increasing PV capacities without making any assumptions on fossil fuel price etc. This is exemplarily shown for an installed PV capacity of 42 GW in Figure 12. Comparing this with Figure 7 one can clearly see how the red load peaks around noon time vanish. In summer time, the residual load at noon may even drop below the load at midnight.

Hour of a day	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	64	64	62	58	54	55	55	53	56	57	58	58
2	62	62	60	53	50	50	51	49	52	53	55	55
3	60	60	58	51	48	48	49	47	50	51	54	54
4	60	60	57	49	46	47	48	46	48	50	55	54
5	60	60	58	50	46	47	47	46	48	50	56	55
6	60	61	59	51	48	47	48	46	49	51	59	56
7	64	65	63	53	49	48	49	49	53	55	65	60
8	70	71	66	56	52	52	52	54	60	62	71	67
9	72	71	66	56	54	54	54	55	62	66	71	69
10	69	68	63	55	53	54	54	55	60	64	68	67
11	68	65	62	53	51	52	52	52	58	62	67	67
12	68	65	61	52	50	51	51	51	56	60	67	67
13	67	63	59	52	50	52	51	51	56	61	66	66
14	66	63	59	50	49	50	49	50	54	59	66	65
15	67	64	59	50	48	49	48	49	54	59	68	66
16	69	66	61	50	50	49	49	49	54	61	71	69
17	73	69	63	52	51	51	51	52	57	62	75	73
18	78	75	68	55	54	54	54	54	61	66	80	77
19	79	79	73	59	59	57	58	59	65	69	80	77
20	77	78	75	64	63	61	62	63	68	73	77	74
21	73	74	72	64	64	63	64	63	69	74	73	71
22	71	72	70	65	62	61	61	62	70	70	70	68
23	71	71	70	64	62	60	60	61	65	66	68	67
24	68	67	66	62	60	59	60	58	61	62	62	62

Figure 12: Change of residual load for a total PV capacity of 42 GW over the day and over the year.

Second, the residual load can be transferred into power prices. Based on the market model and the assumptions described above, we get the following results:

Figure 13 shows the average annual wholesale price for the different scenarios. Due to the assumed increase in fossil fuel prices, the absolute level increases for all scenarios in 2020 compared to 2010. Within the scenarios for 2020, however, one can see the expected reduction of the power price as a function of PV capacity.

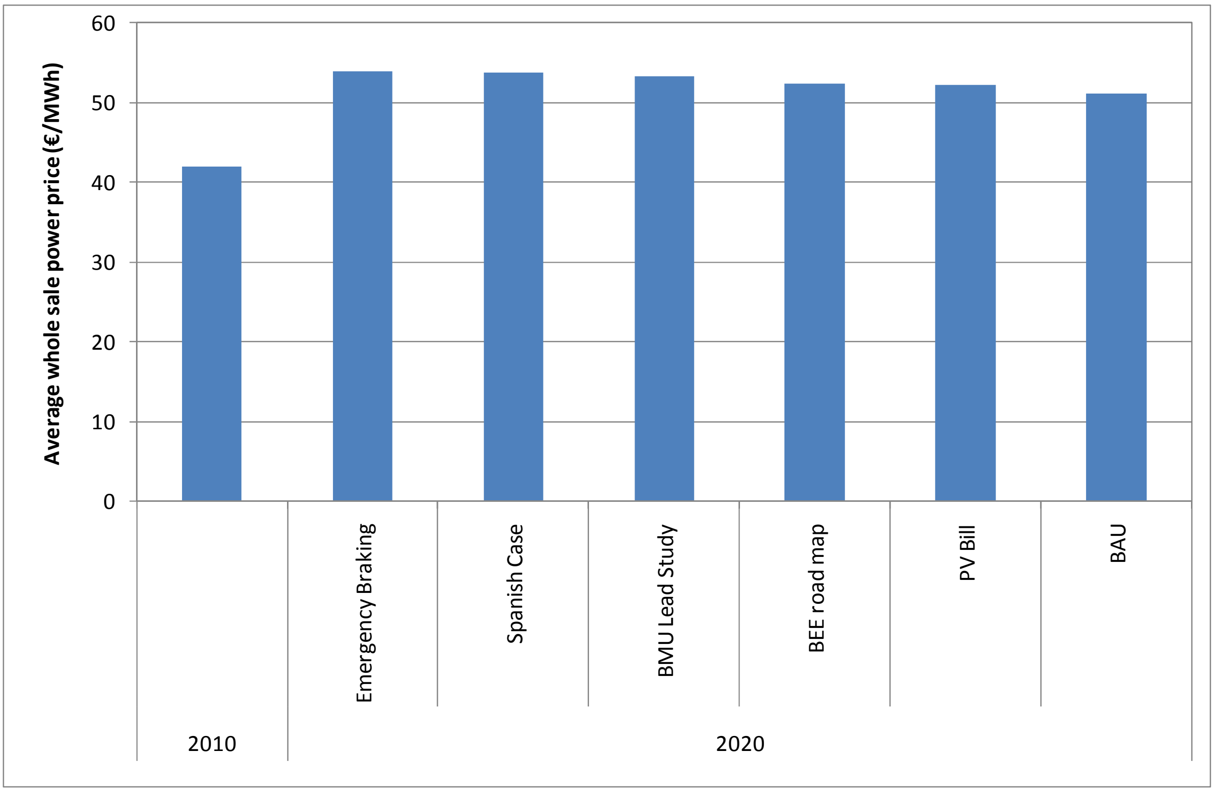

Figure 13: Change of average annual wholesale power price for different scenarios. For scenario definitions see Table 2.

As it is debatable what should be the reference case to compare the different scenarios to, Table 3 indicates the consequences of choosing different reference cases. The table should be read in the following way: When "Emergency breaking" is chosen as the reference scenario, the power price would decrease by 3% if PV capacity increases to "PV Bill" levels. If one considers the "BMU Lead Study" as something that will happen anyway and, thus, as the preferred reference case, then the average power price is reduced by 1.9% if PV capacity increases to "PV Bill" numbers.

Table 3: Change of annual average power price depending on selected reference scenario.

Power Price	**Reference Scenario**					
Compared scenario	Emergency Braking	Spanish Case	BMU Lead Study	BEE Road Map	PV Bill	BAU
Emergency Braking	x					
Spanish Case	-0.3%	x				
BMU Lead Study	-1.1%	-0.8%	x			
BEE road map	-2.7%	-2.4%	-1.6%	x		
PV Bill	-3.0%	-2.7%	-1.9%	-0.3%	x	
BAU	-5.2%	-4.9%	-4.1%	-2.6%	-2.3%	x

Based on the wholesale power prices, one may then determine the weighted market volume. This figure is calculated by summing up the product of the residual load and the corresponding power price for each of the 8,760 hours of a year. It corresponds to the annual revenues of all conventional power plants. The results are shown in Figure 14 and Table 4. When comparing the scenario “Emergency Braking”, which has no additional PV capacity, with the figure for 2010, the market volume must of course increase as power prices are assumed to be rising (see Figure 13) while the total demand remains constant. The picture changes, however, with higher PV capacities. For the extreme scenarios “BAU” with 53 GW installed capacity in 2020, the weighted market volume even decreases below the 2010 level. This can be explained by the fact that the market volume is a product of price and quantity. As shown above, residual load (i.e. quantity) is systematically reduced at day time. As shown in Figure 11, a change of price and quantity at that time has an over proportionate effect on revenues compared to changes at night time.

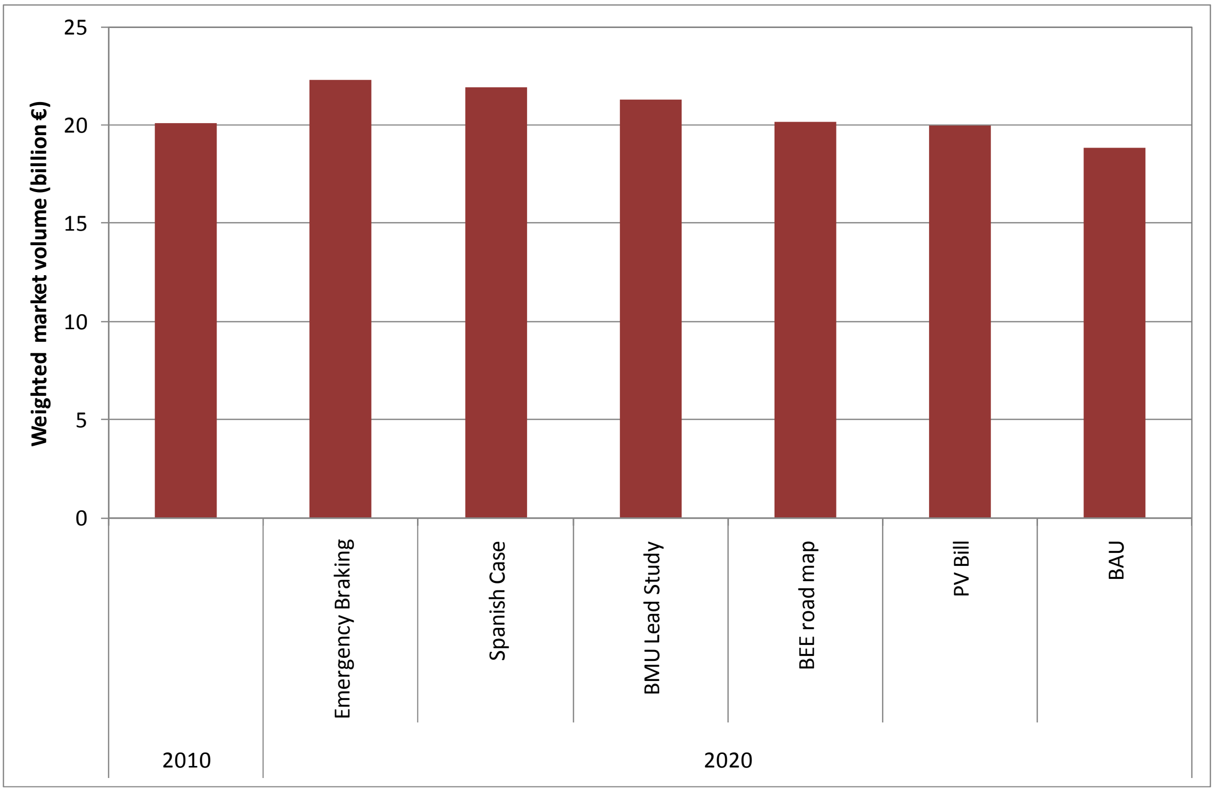

Figure 14: Weighted market volume for different scenarios. For scenario definitions see Table 2.

Table 4: Change of annual market volume depending on selected reference scenario.

Market volume	**Reference Scenario**					
Compared scenario	Emergency Braking	Spanish Case	BMU Lead Study	BEE Road Map	PV Bill	BAU
Emergency Braking	x					
Spanish Case	-1.6%	x				
BMU Lead Study	-4.5%	-3.0%	x			
BEE road map	-9.5%	-8.1%	-5.3%	x		
PV Bill	-10.3%	-8.9%	-6.1%	-0.8%	x	
BAU	-15.4%	-14.0%	-11.4%	-6.4%	-5.6%	x

Having discussed the total market volume for conventional power plants, it might also be of interest to analyse individual conventional power plants. Figure 15 and Table 5 show the annual contribution margin of a coal-fired power plant similar to the one in Rostock. Built in the mid nineteen nineties, it has a capacity of about 415 MW and an electrical efficiency of 42.3%. The general decrease of the contribution margin for 2020 compared to 2010 can be explained by the fact that both, fuel and CO_2-prices, increase. For the different scenarios in 2020, it can be seen that the total contribution margin can be reduced by up to 26% (comparing “Emergency Braking” and “BAU”).

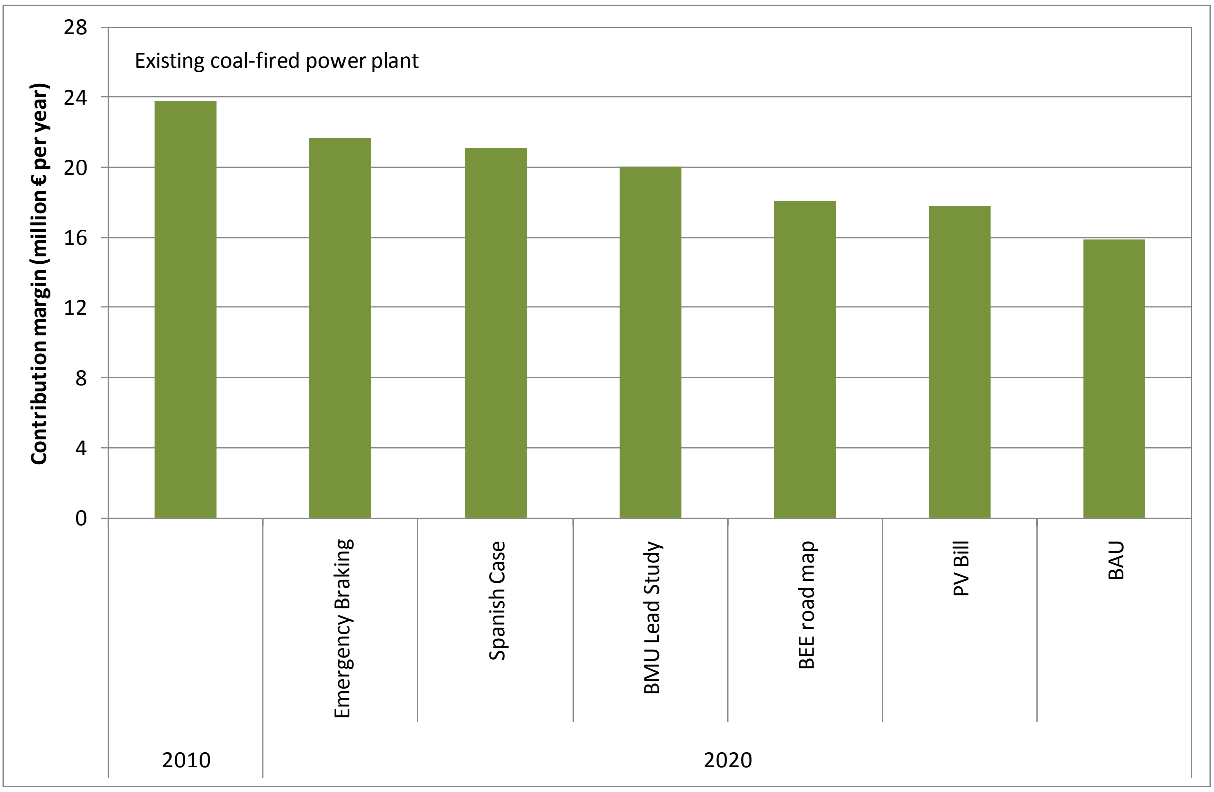

Figure 15: Annual contribution margin for a selected coal-fired power plant under different scenarios. For scenario definitions see Table 2.

Table 5: Change of annual contribution margin of an existing coal-fired power plant depending on the selected reference scenario.

Contribution margin coal			Reference Scenario			
Compared scenario	Emergency Braking	Spanish Case	BMU Lead Study	BEE Road Map	PV Bill	BAU
Emergency Braking	x					
Spanish Case	-2.4%	x				
BMU Lead Study	-7.4%	-5.1%	x			
BEE road map	-16.4%	-14.3%	-9.7%	x		
PV Bill	-17.7%	-15.7%	-11.2%	-1.6%	x	
BAU	-26.6%	-24.8%	-20.8%	-12.3%	-10.8%	x

Finally, a hypothetical new gas-fired combined cycle (CCGT) power plant is considered. State-of-the-art is an electrical efficiency of 58% and an electric capacity of 400 MW. Figure 16 and Table 6 show the annual contribution margin for such a plant. For the different scenarios in 2020, the total contribution margin can be reduced by up to 33% (comparing “Emergency Braking” and “BAU”).

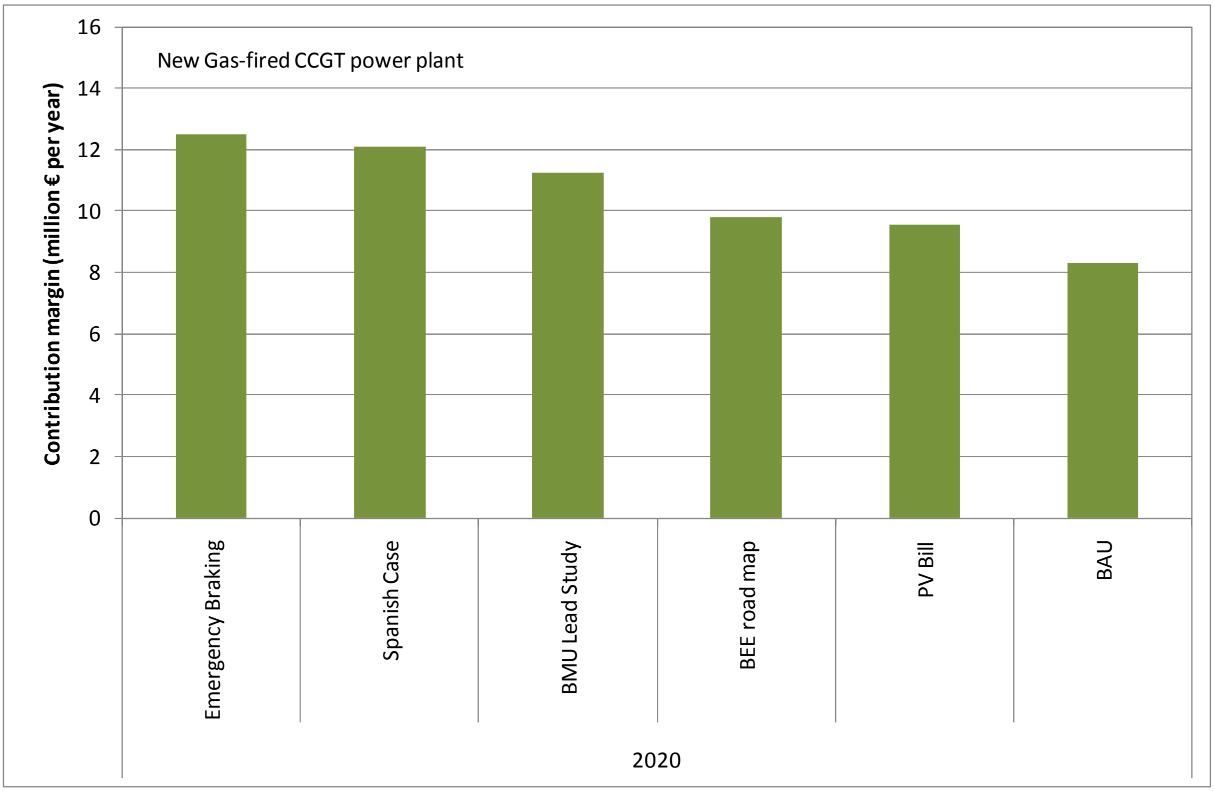

Figure 16: Annual contribution margin for a new CCGT power plant under different scenarios. For scenario definitions see Table 2.

Table 6: Change of annual contribution margin of a new CCGT power plant depending on the selected reference scenario.

Contribution margin gas	Reference Scenario					
Compared scenario	Emergency Braking	Spanish Case	BMU Lead Study	BEE Road Map	PV Bill	BAU
Emergency Braking	x					
Spanish Case	-3.2%	x				
BMU Lead Study	-10.2%	-7.2%	x			
BEE road map	-21.8%	-19.2%	-13.0%	x		
PV Bill	-23.5%	-21.0%	-14.9%	-2.2%	x	
BAU	-33.4%	-31.2%	-25.9%	-14.9%	-12.9%	x

The change in the contribution margin as a function of new PV capacities has two different reasons. First, there is an impact on quantity sold because the residual load is reduced due to the build-up of PV capacities (compare Figure 7 and Figure 12). Second, there is a price effect because the equilibrium price for residual load is lower for higher PV capacities [see also Bruckner et al. 2010]. Whether or not only one or both reasons apply depends, inter alia, on the individual plant and the market characteristics in each hour. Plants may, thus, be affected differently over the course of a year.

2.3.3 Excursus: Nuclear energy policy and its analogy to PV

This section provides a short excursus on nuclear energy policy in Germany. Although it is discussed almost completely separate from PV, it seems important to have this discussion in mind. There are some analogies and correlations, and arguments used in one debate can easily be transferred to the other.

The nuclear phase-out was agreed upon in 2002 under a coalition of the Social Democratic Party (SPD) and the Green Party. Since then, there are caps in place for the remaining amount of electricity that may be produced by the existing nuclear power plants.[8] While the Stade nuclear power plant has already been shut down, some of the other installations will presumably generate electricity until 2022. Concrete shut-down dates are not available since the remaining quantities of permitted electricity production may be transferred among the different power plants. The decision to phase out nuclear power generation has been criticised over and over again, as concerns are brought forward regarding the “security of supply” – as could be seen recently in the case of a closed gas pipeline from Russia – and the potential increase of electricity prices and CO_2 emissions. Liberals (FDP) and the Conservatives (CDU/CSU) called for a revision of the phase-out already during the election campaign in 2009. After the three parties had won the elections, the new Government recently announced, that they have asked research institutes to analyse the effects of an extension of the permitted production time by 4, 12, 20 and 28 years.

Interestingly, the effects of a revision of the current phase-out plan on the power market resemble to a certain degree the analysis for the PV market: If the remaining operational time for nuclear plant are extended the merit-order curve is shifted to the right compared to the future situation where nuclear plants are shut down. As a consequence, power prices decrease (cf. Figure 4). This will, in the same way as for PV, decrease the market volume and the contributions margins of the competing power plants. If the phase out is realised as currently planned, nuclear capacities will disappear altogether and prices will increase.

While this has been discussed among energy economists for quite some time (see for example Bode 2007, Matthes 2009 etc.), the implications have only very recently been realized by other power generators. In the first half of March 2010, some 150 municipal utilities started to openly lobby against a revision of the phase-out program. They are supported by the VKU, the association of German municipal companies. The utilities threaten to stop any

[8] See “Gesetz zur geordneten Beendigung der Kernenergienutzung zur gewerblichen Erzeugung von Elektrizität” (German law on orderly termination of the use of nuclear energy for the commercial generation of electricity) of 22 April 2002, Appendix 3.

further investments in efficient power plants, if the nuclear phase out is revised. They argue that the decisions for new investments were and have to be based on a stable investment environment, which would be considerably and unfavourably changed (for them), if government opted for a revision of the phase-out. This issue has also entered the mass media and is part of documentaries on TV.

Although municipal utilities invest in renewable energy themselves, it remains to be seen how these companies will react, if they realize that an unconditional support of PV for the next 10 years or more also adversely effects their investments or investment plans.

Finally, it has to be stressed that a combination of a continued PV capacity build-up and a revision of the nuclear phase-out will interact to amplify the adverse effects on other market players described in this study.

3 IMPLICATIONS FOR POLICY MAKERS AND STAKEHOLDERS

As we have shown in the previous chapters, a massive increase of the installed PV capacity has major impacts on the German electricity market that have not yet been considered in the public debate. To stress this point, one may look at the draft of the new EEG bill. The mandatory regulatory impact assessment mentions the following aspects [Bundestag 2010, p. 6-8]:

- costs for the public budget,
- costs for the business sector,
    - device manufacturers and operators,
    - companies as power consumers, and
- costs for the citizens (private households).

Costs for power <u>producing</u> companies are not even listed. In economic terms, however, revenues, which are not realised, also form part of the costs. In this sense, an important aspect of the PV support scheme has simply been neglected until now.

In order to understand the relevance of this oversight, one has to keep in mind, that the power sector in general is still undergoing deep structural changes and that it faces a major problem: in the liberalised power market in Europe there are currently little if any incentives to invest in new conventional power plants. The three main reasons for this are:

1. Price formation based on marginal costs:
   Given the relatively high capital intensity and the (technical) restrictions for reducing marginal costs of production through innovations, it is almost impossible to recover capital costs [Weber 2002, BCG 2003].
2. Uncertainty about long-term emission targets for the power sector:
   As there are currently no long-term (international) climate agreements, it is difficult for investors to foresee the future price of carbon. While this is also the case for fuel prices, the price of carbon is much more dependent on policy decisions and adds to the uncertainty.

3. The increase of renewable energy capacities:
   By increasing the capacity of renewable energies through some support scheme, power prices and marketable quantities for conventional plant operators are systematically reduced.

For a more detailed analysis of the issue see Bode & Groscurth [2009a+b]. In February 2010, the British regulator Ofgem presented a consultation document on “Options for delivering secure and sustainable energy supplies” [Ofgem 2010, p. 1]. It states:

> *“We have identified a number of concerns with the current arrangements and have concluded that significant action will be called for given the unprecedented challenges facing the electricity and gas industries. […] Prompt action will reduce the risk to energy supplies and environmental objectives, and can help reduce costs to consumers.*
>
> *We have put forward for consultation a wide range of possible policy measures, ranging from improvements in pricing and/or obligations on suppliers to deliver specific levels of supply security, through to models that mandate or secure specific investments in new generating capacity and gas infrastructure.”*

We believe that these findings are also valid for Germany. One might argue that lacking incentives for new conventional power plants need not concern us, since we are striving for 100% electricity from renewable energies in the long-term anyway. Still, for a foreseeable future, flexible conventional backup capacities for times when the sun is not shining and the wind does not blow are imperative – be it gas-fired power plants or sufficient storage capacities (cf. Figure 12).

Although politics has declared 100% renewable energies a long-term objective, it has neither been discussed what the technically and economically optimal mix of technologies for such a scenario would look like and what the appropriate path would be to get there, nor has it been analysed what the market rules for such an energy system would have to look like.

To reduce the danger of locking-in into a dead end path, it is necessary to immediately start a broad discussion on these issues. Nevertheless, the question remains how to deal with the market impacts of PV in the short-term. There are two choices: Either, we let the rapid build-up of renewable energy triggered by the EEG and the induced structural change of electricity system continue and deal with its consequences, or we try to slow down the build-up of additional PV capacities.

Letting the rapid build-up continue

If we want to maintain the speed of the structural change, we may leave the PV support scheme as it is and accept its additional costs as a necessary price for the intended change. Consequently, we would have to attend to the following issues:

First, since backup capacities in the form of fully flexible power production facilities are mandatory in a power system based on renewable energy, we would have to (promptly) set up an incentive scheme for such investments. This would involve a number of questions such as, for example, if and how national incentive schemes are compatible with European law.

Since contribution margins are lowered by the PV build-up (cf. Sec. 2.3.2) these additional incentives would have to be higher than without additional PV capacity.

Second, we would have to deal with the fact that a number of rather new conventional power plants may become stranded investments and that their owners will be lobbying for compensation.

Third, we will have to consider the distributive issue of the additional costs. This should be discussed explicitly and it should be made transparent who will have to bear the cost in the end.

Finally, we have to acknowledge that a mere extension of the remaining production for nuclear plants is not a solution, but will exacerbate the problem. The residual load to be satisfied by conventional power plants is decreasing systematically. In addition, it fluctuates on an hourly basis or in even shorter intervals. Nuclear power plants are not well suited to follow such rapid load changes. Rather, together with lignite-fired power plants, they form the backbone of base-load plants in the current system. Operators of these plants have developed a new strategy to defend their revenues. If they take their plant out of operation for just a few hours, they have to face substantial shut-down and start-up costs as well as technical restrictions such as minimum up- and down-times. Therefore, they are ready to pay money for the right to produce electricity for those few hours. Since 2009, the German power exchange EEX supports this behaviour by allowing negative price bids.

Experience in a number of hours in 2009 has shown that power prices will not only drop to zero or negative values if the residual load is zero, but also when the residual load is in the order of magnitude of the available base load power plants.

If, however, market prices become negative, it will not only concern the conventional plants, but system operators trying to sell the electricity from renewable energy installations supported by the EEG would have to pay that same price instead of generating revenues which are meant to partly cover the costs of the EEG. In turn, this will further increase the costs of the EEG for power consumers.

Altogether, we have to conclude that maintaining the speed of the PV capacity build-up will require a rapid, far-reaching redesign of the electricity market and will be accompanied by additional acceleration costs.

Slowing down the build-up of PV capacity

If we want to slow down the build-up of PV capacity, intuitively one would think about cutting the feed-in tariffs for PV. A mere adjustment of the FiT to the total costs of production in order to avoid over-subsidising (see Section 1.2) does not suffice, though. This measure will only serve to avoid unwanted additional profits for investors and manufacturers. Nevertheless, as long as new installations are economically attractive one would expect a continued increase in PV capacities.

Having said this, it becomes clear that the current draft bill is not fully suited for decelerating the development. Currently, an annual new PV capacity of about 3 GW per year is deemed desirable. This will still lead to some 40 GW peak capacity in 2020, which already has a deep impact on the electricity market as shown above. However, there is no guarantee, that the desired level will be met. It is rather likely, that this will not be the case. PV module production follows the same economic rules as electricity production, which means that, once the factories producing the modules have been built, the ultimate selling price should drop to marginal production costs. In a situation of sufficient supply, any reduction in the FiT will, thus, lead to a reduction of module prices until the marginal cost will be reached. Consequently, the build-up of PV capacity cannot effectively be slowed, or more precisely, it can only be slowed if feed-in tariffs are set below marginal costs of production. That, however, will completely take away the incentive to invest in PV in Germany and it will put the economic health of the PV industry at risk. Therefore, if one wants to slow the expected speed of change in the power sector, the only way will be to set an absolute cap on the added PV capacity (in MW) such as it is already in place, for example, in Spain.

Conclusions

One may find arguments for both paths. Either we continue on the current path of building up PV as currently expected, fostering a rapid change in the energy sector as a response to climate change and to decentralise the power sector. Or we may slow down the PV capacity build-up to avoid possible stranded investments and to buy some time for the development of a convincing path for our energy supply in the future. We feel, however, that the full implications of the expected PV development have not been realised by policy makers, plant operators, and other stakeholders. The discussion on PV feed-in tariffs may, thus, have to be reopened again. With regard to increasing the share of power from renewable energies one should also note that a megawatt-hour from PV can be substituted by a megawatt-hour from, say, wind energy. This might be cheaper in a double sense: the generation cost itself and the costs for the remaining players on the market. The time for treating all renewable energies alike – as it has been for the last 20 years – might, thus, come to an end soon.

The way of supporting PV may be considered as the accelerator pedal for structural change in the power sector. The higher the speed of change is, however, the more likely stiff resistance by incumbent operators becomes. The excursus on the reaction on a possible revision of the nuclear phase out may serve as an illustration (cf. Sec. 2.3.3). With regard to PV, municipal utilities and the four large utilities (EnBW, Eon, RWE, Vattenfall) may even form an alliance on this issue as they own the same class of assets.

APPENDICES

Abbreviations

€	Euro
€/MWh	Euro per megawatt-hour; 1 €/MWh = 1/10 c€/kWh
BMU	Bundesministerium für Umwelt, Naturschutz und Reaktorsicherheit (www.bmu.de) / German Ministry for the Environment, Nature Conservation and Nuclear Safety
c€, ct	Euro-Cent
CCGT	Combined cycle gas turbine (power plant)
CO_2	Carbon dioxide
dena	Deutsche Energie-Agentur / Germany Energy Agency, Berlin (www.dena.de)
EEG	Erneuerbare-Energien-Gesetz / Renewable Energy Act
EEX	European Energy Exchange in Leipzig (www.eex.com)
EU	European Union
FiT	Feed-in Tariff
GW	Gigawatt = 1,000 MW
GWh	Gigawatt-hour = 1,000 MWh
h	Hour
kW	Kilowatt = 1,000 Watt
kWh	Kilowatt-hour = 1,000 Wh
M€	Million €
MW	Megawatt = 1,000 kW
MWh	Megawatt-hour = 1,000 kWh
Ofgem	Office for gas and electricity markets (the British regulator, www.ofgem.gov.uk)
PV	Photovoltaics
RE	Renewable energy
TWh	Terawatt-hour = 1 Million MWh
VKU	Verband kommunaler Unternehmen / Association of Municipal Utilities (www.vku.de)
W	Watt (electric power)
Wh	Watt-hour (physical work delivered); 1 Wh = 3,600 Ws = 3,600 J

Assumptions on Model Data

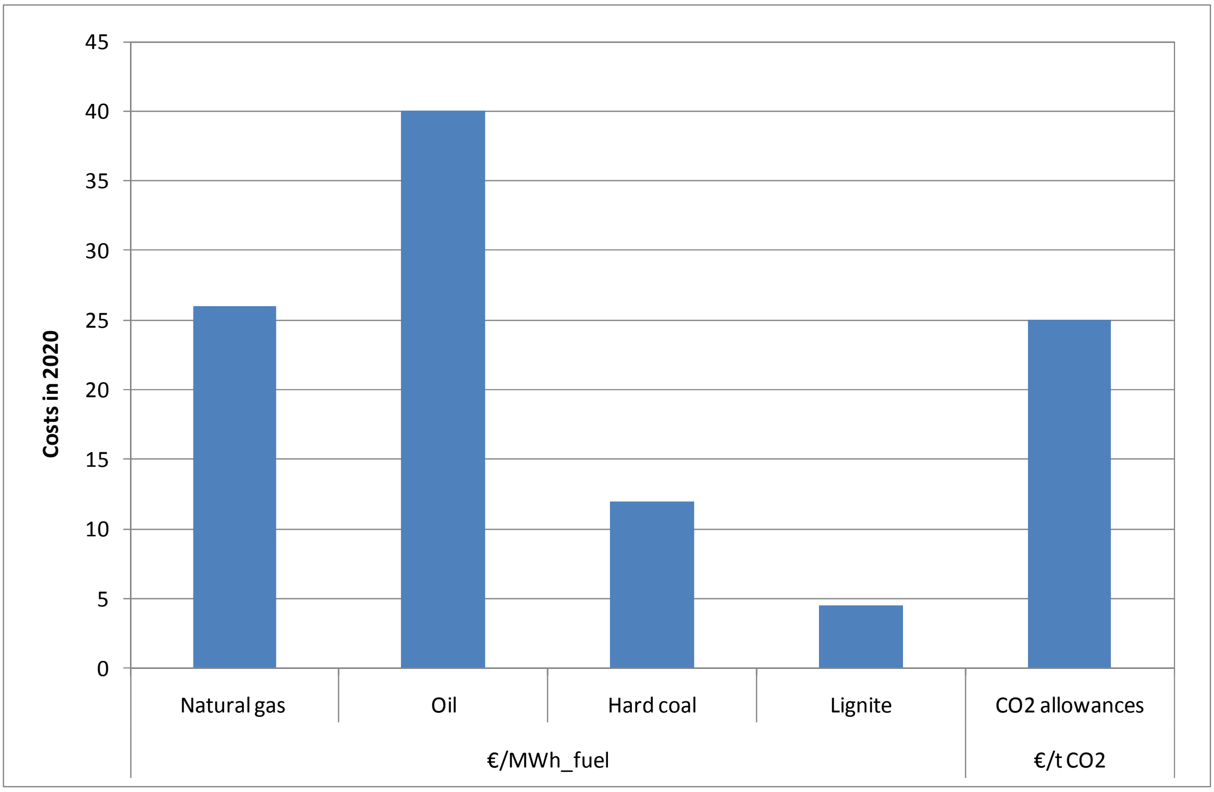

Figure 17: Fuel and CO_2 prices for the target year 2020 (in real prices).

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