The Impact of PV on the German Power Market

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ABSTRACT

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. In summer 2010 a bill was passed amending the current FiT.

Both, in the discussion and in the 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 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. 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%.

The study 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 bill will 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.

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. 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. Altogether, Germany is one of the most important PV markets in the world, if not the most important.

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 "Lead Study Renewable Energies", commissioned by the federal research ministry, for example, depicted the additional costs from PV in 2007. 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 surpassed by 2008. Other studies from the same time also completely underestimated the development [EPIA 2006].

The 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. 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.[2] 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.

Interestingly enough, the discussion has so far neglected one important fact: The impact of PV on the power market – that will be studied below.

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

[2] The exact calculation depends on a reference period.

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.[3] 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.[4]

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:

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

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[3] 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.

[4] 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 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.

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."* [5] 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.

In order to describe the pricing on the power exchange, only the so-called spot market will be considered in the following.[6] 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. 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.

But 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.

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

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[5] 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.

[6] 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.

the public energy policy debate in a meaningful way. The consultation paper by British regulator ofgem may be perceived of one exception (for more on this see below). 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. Consequently, prices on the power exchange are constantly moving up and down over the day and over the year. 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. 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 1 shows the relative distribution of load over the year. As discussed earlier, prices are generally high when the load is high (red cells) and are low when the load is low (green cells).

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 1: Average daily load curves for different month (load in GW).

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 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. As a consequence, the equilibrium price decreases. [Bode et al. 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 & et al. 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. In other words, the merit-order effect can be diluted or strengthened by the choice of technology.

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. 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 = €). 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. 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.

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. 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 1: 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.

Second, the residual load can be transferred into power prices.

As it is debatable what should be the reference case to compare the different scenarios to, Table 2 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 2: 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 Table 3. When comparing the scenario "Emergency Braking", which has no additional PV capacity, with the 2010 weighted market volume of 20,07 billion €, the market volume must of course increase as power prices are assumed to be rising 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 to 18,86 billon €. 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. A change of price and quantity at that time has an over proportionate effect on revenues compared to changes at night time.

Table 3: 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. Table 4 shows 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%. While the contribution margin in 2010 is at 23,8 million € per year, the scenario with the highest contribution margin in 2020 is "Emergency Braking" at 21,6 million € per year. All other 2020 scenarios have even lower margins. The general decrease of the contribution margin in 2020 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").

Table 4: 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. Table 5 shows the annual contribution margin for such a plant. For the different scenarios in 2020, ranging from 12,51 million € per year for "Emergency Braking" to 8,33 million € per year for "BAU", the total contribution margin can be reduced by up to 33% (comparing "Emergency Braking" and "BAU").

Table 5: 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. 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.

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 producing 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.

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. 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.

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Die Auswirkung der Photovoltaik auf den deutschen Strommarkt

Die Diskussion um die Einspeisetarife für Photovoltaik-Anlagen in Deutschland hat in den letzten Monaten stark zugenommen. Ein Diskussionspunkt ist die Tatsache, dass die im Vergleich zu den Einspeisetarifen stärker sinkenden Preise der Module zu einer Überförderung führen. Auf der anderen Seite stehen die zunehmenden Stromkosten für die Verbraucher durch die beispiellose Zunahme der PV Kapazitäten in Deutschland zuletzt in 2009 und auch in 2010.

Nach den Bundestagswahlen im September 2009 wurden verschiedene Vorschläge zur Anpassung der Einspeisetarife gemacht. Sowohl in der Diskussion als auch im nachfolgenden Gesetz wird ein wichtiger Aspekt nicht berücksichtigt: Der Einfluss der sehr stark wachsenden PV Kapazitäten auf die Wirtschaftlichkeit von konventionellen Kraftwerken.

Der vorliegende Beitrag schließt die Lücke. Der erste Teil zeigt qualitativ wie sich der Strompreis und die Gleichgewichtsmengen auf dem Strommarkt ändern mit wachsenden PV Kapazitäten. Diese Erkenntnisse verdeutlichen die sinkenden Einnahmen für Betreiber konventioneller Kraftwerke. Der zweite Teil der Studie liefert eine quantitative Untersuchung des deutschen Strommarktes. Weiterhin werden die Effekte der verschiedenen PV Szenarien auf die Stromeinkaufspreise und die totalen Einnahmen (d.h. Preis multipliziert mit Menge) aller konventioneller Kraftwerke kalkuliert. Der Deckungsbeitrag eines etablierten Kohlekraftwerkes könnte um mehr als 25% sinken, der Deckungsbeitrag eines Gaskombikraftwerkes um mehr als 30%. Sowohl für bestehende wie auch für geplante neue Kraftwerke ändern sich die wirtschaftlichen Rahmenbedingungen massiv.

Die Studie kommt zu dem Schluss, dass die PV-Förderung als Gaspedal für strukturelle Änderungen im deutschen Strommarkt verstanden werden kann. Wenn die im Gesetz genannten Ausbauziele für PV tatsächlich erreicht werden, muss das Marktdesign des deutschen Strommarktes umfassend und zügig angepasst werden, insb. um ausreichende Anreize für Investitionen in Back-up Kapazitäten u.a. für sonnenarme Zeiten zu schaffen. Dabei würden weitere Kosten entstehen. Obergrenzen (Caps) für die neue PV-Kapazitäten, statt weitere Kürzungen der Tarife könnten helfen, den Markt vorsichtiger umzugestalten und den Widerstand etablierter Betreiber zu reduzieren.