INSTITUT FÜR ENERGIE- UND KLIMAPOLITIK
INSTITUTE FOR ENERGY AND CLIMATE POLICY

Discussion Paper

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A Revision of the Concept of "Levelised Costs of Electricity" in the Context of the Transition of Power Systems Towards 100% Renewables

or:

A Proposal for a Cost-efficient Path Towards the "Energiewende"

Hamburg, June 2013

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1 Summary[1]

The massive increase of the German Renewable Energy Act levy at the beginning of 2013 has started intensive discussion on this instrument for promoting renewable energy. In this context, at the end of January Federal Environment Minister Altmaier presented proposals for a so-called electricity price brake ("Strompreisbremse" or power price cap). The proposals focus on the one hand on a limitation in the increase in the surcharge in the future and on the other hand on a modified distribution of the resulting costs (EEG surcharge). Interestingly, focussing on a cost-efficient expansion of electric power from renewable energies is not addressed. From an economic perspective this should, however, be the starting point of the discussion.

This paper addresses this issue and proposes a new methodology for identifying a cost-efficient path for expansion on the way to an energy transition to 80% power from renewable, also referred to as "Energiewende" in Germany. The focus is not placed on "theoretical" power generation costs of wind or photovoltaic plants as they are used regularly in the discussion. Rather, the approach is based on the average overall costs of the directly usable quantity of electricity of the last installed plant. The reason for using this perspective is the fact that as part of an energy transition, the high levels of capacity of wind power or photovoltaics increasingly leads to surpluses that cannot be directly used, thus generating higher costs. At the same time, the paper evaluates for the first time the interaction of different intermittent technologies (wind power and PV) in the analysis of the electricity production costs: In systems with a high proportion of such technologies, construction of a new, additional plant affects the relevant cost curves of any technology, as the respective residual-load curve changes. The analysis of electricity production costs in isolation from the corresponding electricity system thus leads to suboptimal results for the composition of the system of plants and the structure for power generation. The results should be taken into account in the context of the discussion of the further development of the German Renewable Energy Law.

A numerical analysis for the Energiewende in Germany for different cost scenarios shows that, for a cost-effective development path of renewable energy, the focus for the coming years should be placed solely on onshore wind energy (at least an additional 85 GW above the current level). Only after this step has been taken will new opportunities open up for additional photovoltaic capacity, even when photovoltaic costs are assumed for today that are not expected until the year 2030. Depending on the annual expansion rate of onshore wind energy, there should be no further installation of photovoltaic plants for the next 20 to 30 years.

[1] The present discussion paper is based on the following earlier German version: Bode, Sven (2013) Grenzkosten der Energiewende: Teil 1 Eine Neubewertung der Stromgestehungskosten von Windkraft- und Photovoltaikanlagen im Kontext der Energiewende, arrhenius Discussion Paper 8. Some figures and lines of argumentations have been change in order to allow for a better understanding.

2 Background

This study takes place against the following background:

A) Germany today has a specific power generation mix, with a proportion of renewable energy of about 25 per cent.

B) Germany has a long-term aggregate development target (80% of electricity from renewables in 2050 [2]) and interim targets along the way (35 % no later than 2020, 50 % no later than 2030 and 65 % by 2040)[3].

However, a systematically developed path to achieve the above-mentioned goals is missing for getting from A to B.

Methodologically, two approaches can be found in the literature up till now:

i) The extrapolation of past trends into the future

ii) System analysis for future target years, such as the year 2050, which describe what a cost-effective system could look like

Ad i)

Here in particular the pilot studies on renewable energies of the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) should be noted.

Ad ii)

Using this approach, an analysis is performed for a specific target year, assuming a "blank slate", for how a cost-effective system would look that would be constructed in that year. Figure 1 shows the result of such an analysis from a recent study in Germany. It should be noted that the authors make it clear that there are several solutions with similar costs.

[2] It appears to still be unclear what proportion of the 80% target of renewables should come from domestic sources. The Federal Ministry for the Environment (BMU) pilot studies have regularly included import of over 10% (see most recently BMU 2012). This contrasts with the issue of the extent to which the import of electricity provides a contribution to supply security (Bode & Dietrich 2011). Independent of this issue, for any given proportion of domestic generation, the question can be posed, what is the most cost-efficient means of provision.

[3] See § 2 Section 1 of the German Renewable Energy Law 2012 (EEG)

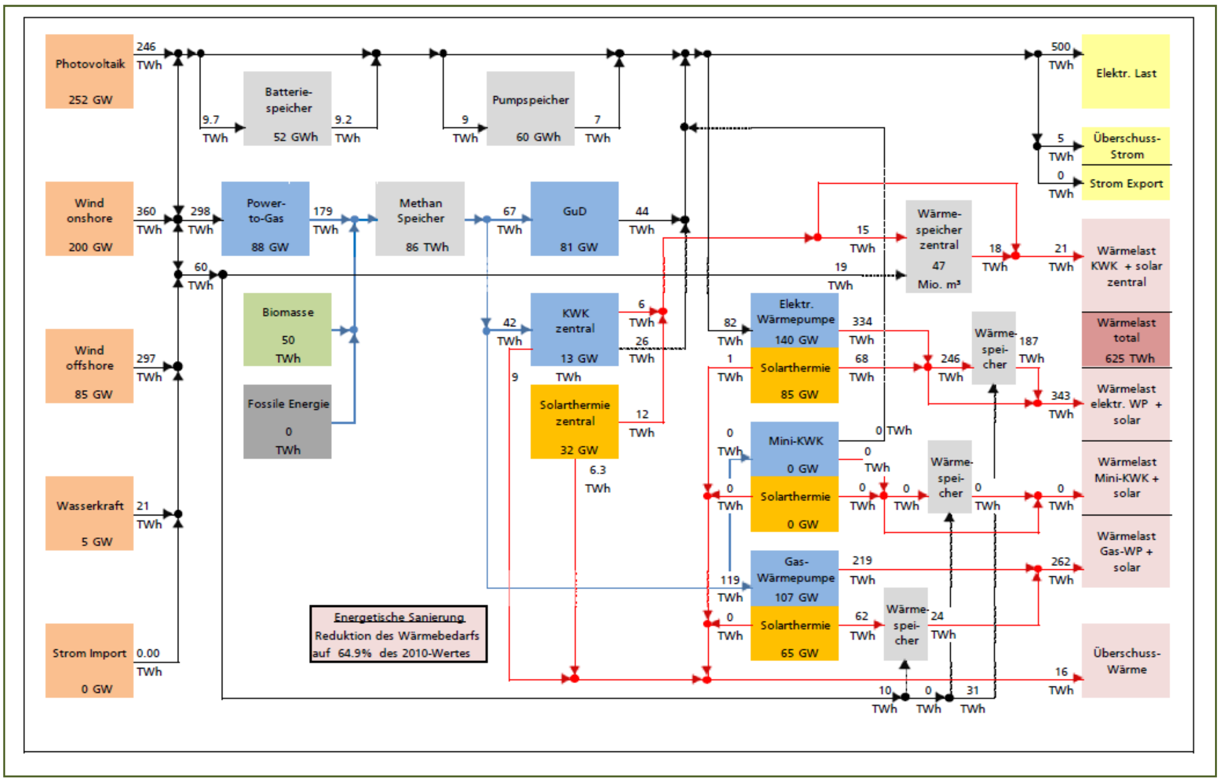

Figure 1: Design for a minimal cost system for 100% supply of electricity and heat from renewable energy sources (source: F-ISE (2012a), p. 16), translations by the author

According to Figure 1, the result would be an installed capacity of 252 GW for photovoltaics and for onshore wind energy 200 GW, both in the year 2050. What these types of analyses do not show, however, is the path to arrive at these end values. Possible options include a linear path from the current capacities to the end values, an asymptotic approximation, and many more alternatives. The need for such technology-specific developments paths has been indicated on several occasions.[4] Interestingly, in the discussion about the energy revolution, the question of a cost-effective development path has been hardly mentioned.

In the following a new methodological approach is presented that addresses the question of a cost-effective development path towards 80% renewable electricity.[5] After the methodical basis follows a numerical analysis for Germany where first onshore wind energy and photovoltaic plants are examined in detail.

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4 See, for example, Bode (2010) Erneuerbare Energien im Strommarkt – heute und morgen, in: Wirtschaftsdienst – Zeitschrift für Wirtschaftspolitik, 90, 10, p. 643-647

5 A discussion of the 80% target is explicitly not part of the present analysis.

3 Marginal costs of the Energiewende: Methodological approach

The title “Marginal costs of the Energiewende” should make clear that the transition from a fossil-nuclear dominated energy system to a system with 80% renewable energy (or more) will be taken in small (marginal) steps not just on the physical level, but also on the cost side. One new renewable plant follows the other.

The concept of marginal cost (more precisely, the marginal costs of production) is well-known not only to economists but also more widely in the circles of energy systems and policy ever since the description of the merit-order effect (Bode & Groscurth 2006). Put succinctly, it describes the additional cost associated with changing the production output by one additional unit. The analysis takes place for existing plants. For investment decisions, the approach is not suitable. Here fixed costs must be taken into account as well. The marginal costs of production therefore do not play a role in the following analysis.

The consideration of the "marginal cost of the energy revolution” is based instead on the following approach:

> ***The expansion of renewable energy ("from A to B") is based on the total average costs of the directly usable electricity of the last built plant***

This approach is explained below.

3.1 Total average cost of intermittent technologies (existing approach)

The above approach is fundamentally different from the current method of calculation. The total average (electricity generation) costs - also known as the levelised cost of electricity (LCOE) - are calculated under the assumption that all of the electricity can be used directly.[6]

Figure 2 shows a typical representation of a possible development of the levelised cost of electricity for renewable energies.

[6] For a formal discussion, refer to Konstantin, Panos (2009), Praxisbuch Energiewirtschaft: Energieumwandlung, -transport und -beschaffung im liberalisierten Markt, Springer, Berlin.

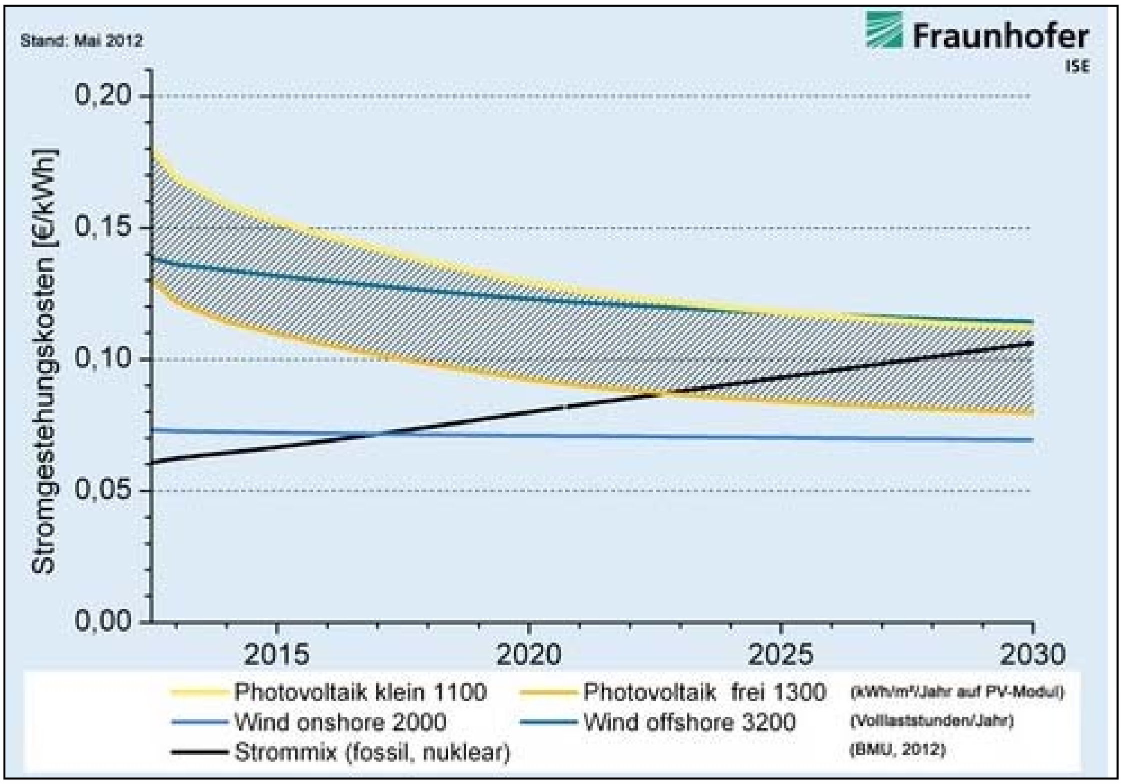

Figure 2: Possible development of electricity generation costs for selected renewable energy technologies (Source F-ISE (2012b), p. 4)

The drop in electricity production costs is based mainly on the following.

> *"Under the assumption of future constant learning rates for PV plants and PV modules (15-20% with a doubling of installed plant capacity, equivalent to a progress ratio of 80-85%) the electricity generation costs of future plants go down ..."*
>
> (Source: F-ISE (2012), p. 4; translation by the author)

In power systems with small proportions of intermittent renewable energy, this is a useful approach. In general or in the global context, such a development may in fact occur. For systems with a high proportion of renewable energies, as discussed below, a broader view is needed.

3.2 Technical parameters of the energy revolution with predominantly intermittent technologies

Intermittent technologies such as wind power or photovoltaic plants do not always produce at full power (e.g. measured in so-called full-load hours)[7]. Instead, the supply depends on the weather. To be able to cover the electricity demand with intermittent technologies, the installed capacity must be (significantly) higher than the maximum load (demand at a certain time). The results presented above (see F-ISE, 2012a), for example call for triple-digit GW capacity for both wind and PV.

High levels of installed capacity result, however, in excess electricity when the wind is strong and there is a high amount of solar radiation, in particular when the actual load is low at these times. These surpluses cannot be used directly, but there are the following options:

- Storage (and subsequent reconversion)
- Shutdown of the generating plant
- Export / network expansion

All three options have in common that they increase the cost of the electricity actually used (in Germany). For storage and export, technical restrictions (capacity and bottlenecks) must be taken into account in the analysis.[8]

3.3 Average total cost of intermittent technologies in the context of the energy transition (new approach for a single technology)

The above remarks have made it clear that a) the question of the cost-effectiveness of the energy transition has been almost completely ignored and b) for the question of costs for the intermittent renewable technologies, in the context of a high proportion of electricity generation, possible new approaches may be needed for the cost analysis due to the increasing expected surpluses.

Against this background, the following approach is proposed: To determine the most cost-efficient development path from the current level to an 80% proportion of renewables, technologies with the lowest electricity production costs are used. In the cost calculation, the total average costs of directly usable electricity generation of the corresponding last installed plant are used. Important[9]: It is not the marginal cost of production of an existing plant that is used, typically assumed to be zero for wind power and PV.

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[7] Number of hours that the plants are calculated to run at full power. For onshore wind power, for example, 1300 to 2000 hours of 8,760 hours a year.

[8] For export there is still the question of which revenues return. This depends on the future market design, among other factors.

[9] In the author's opinion, the concepts "marginal production cost" and average total cost are used in a misleading manner in the current political debate. The difference is of central importance for the discussion of the cost of the energy transition.

The difference in the approaches is also explained graphically. Figure 3 shows the regularly encountered assumption that the electricity production costs are at the same level for every possible capacity level at a specific point in time (e.g. 2030).

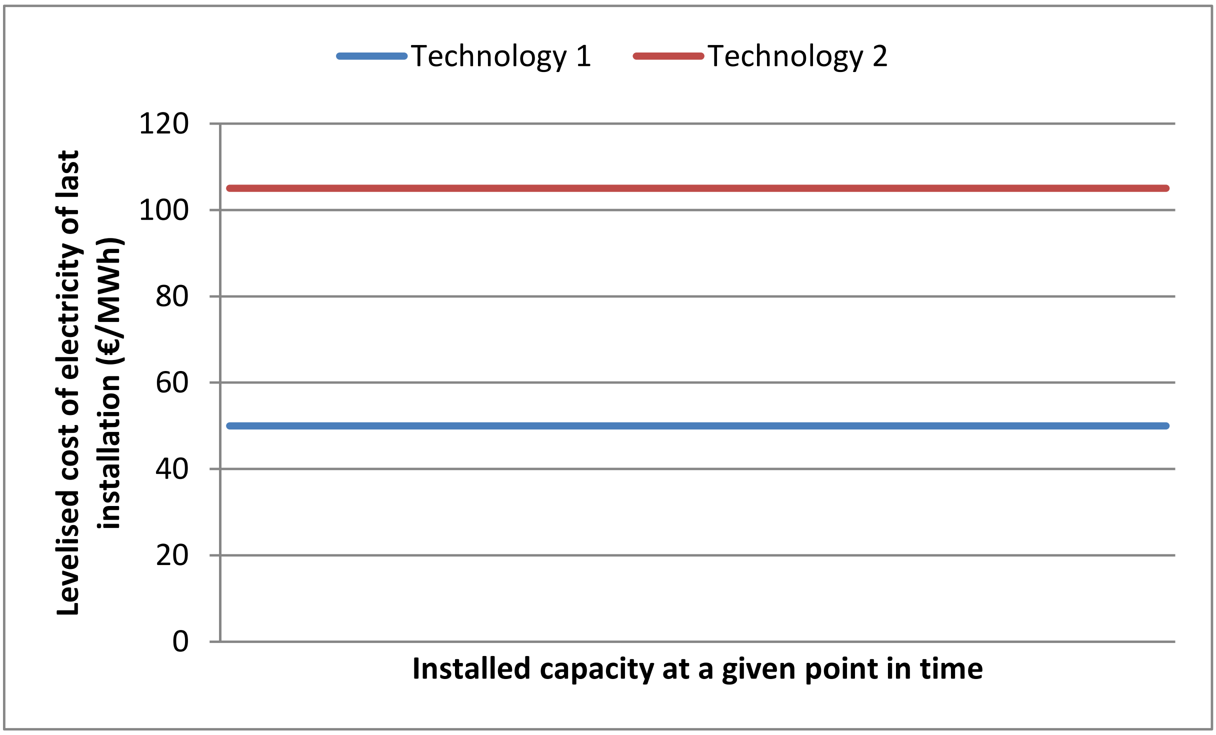

Figure 3: Average electricity production costs of the final system as a function of installed capacity (conventional view)

Figure 4 demonstrates, however, with an example, how the proportion of the directly usable electricity changes during the development of the electricity system. The figure shows the load and the feed-in profile of "onshore wind energy" for a day in May in 2011. Assuming that the wind profile of that day could also be observed in 2030 or 2050, the capacity levels 1 to 4 show the effect that the increase in installed capacity could have. The increase from level 1 to 2 is not critical. When level 3 is reached, a limit is reached: the entire generated electricity can be directly used by consumers in the evaluated period. By now increasing the installed capacity to level 4, a portion can no longer be used directly and falls into one of three options: save, shut down or export.[10]

To make the effects more clear, let us assume that the jump from level 3 to level 4 is achieved by an individual plant. Using the figure, the new approach for the calculation of the total average costs can be clearly demonstrated. The total costs are now determined on the basis of the amount of energy that can be used directly, i.e. for the amount of electricity generated in the interval 1 am to 4 pm and 8 pm to 12 am (the yellow area).

[10] Due to regional bottlenecks, this phenomenon can already be observed today on a small scale.

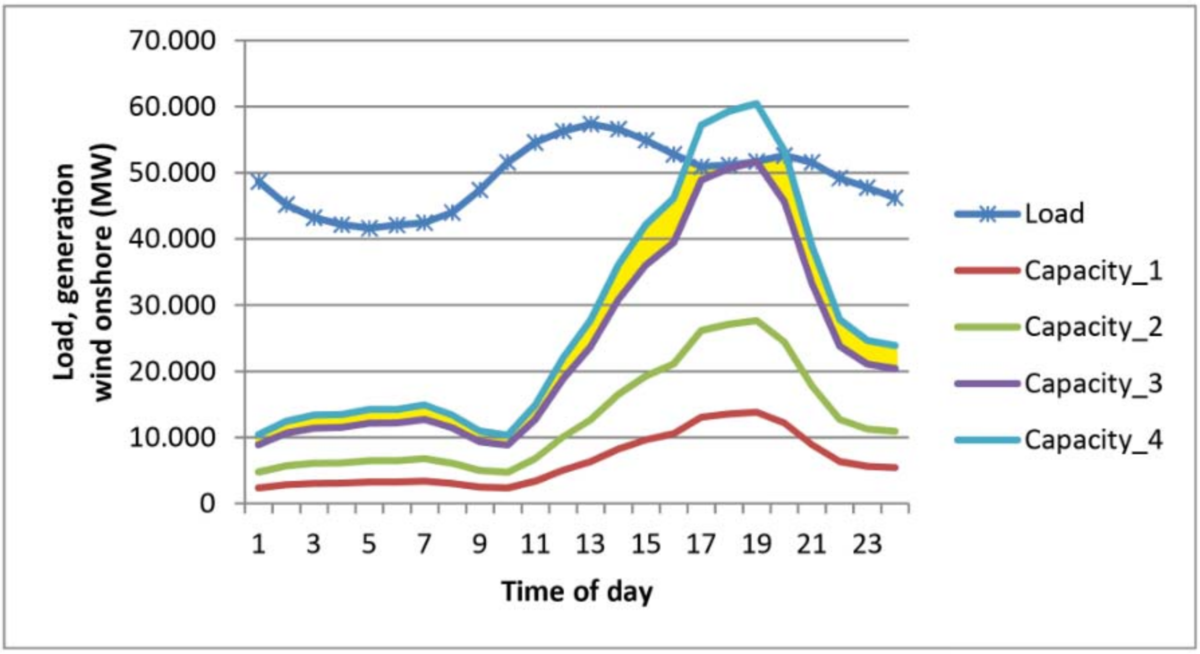

Figure 4: Feed-in profile at different installed capacities of onshore wind energy and calculation of not directly usable energy

If one expands the above analysis out for an entire year, a cost development results as shown in Figure 5. Local network bottlenecks were not taken into account here. As can be seen, it is possible to add approximately 20 GW to the current level before the total average costs of the directly usable electricity generation of the last installed plant (in the following abbreviated as TAC-LP), here represented in 1,000 MW steps, slowly start to rise. With the rise in the TAC of the last plant, the TAC of the directly usable electricity generation of all plants in Germany rise (blue curve). The slope of the average total cost curve for the last installed plant (red curve) increases, meaning that the costs are disproportionately higher.

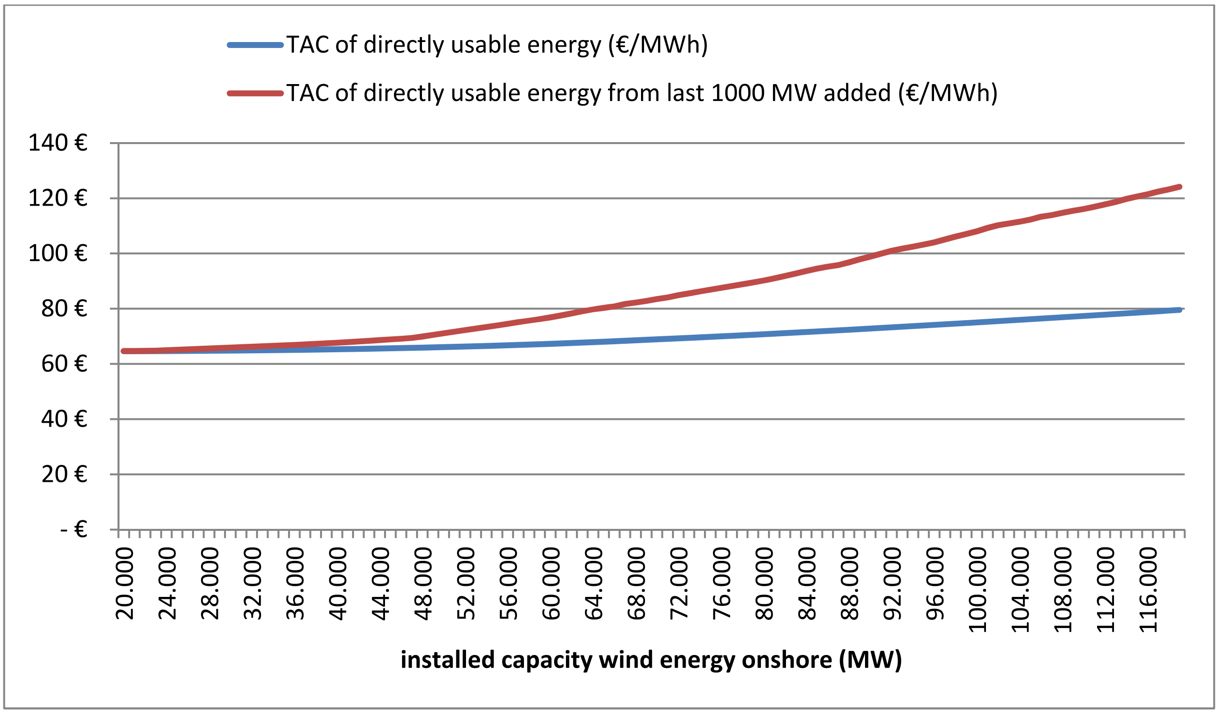

Figure 5: Average total cost (TAC) of directly usable energy in the development of onshore wind power in Germany (feed-in and load profile from 2011; installed wind and PV capacity as of 31.12.2012; costs see Table 1)

The TAC-LP can also be used to answer the question of the option to be selected: save, shut off, export / network expansion. The question then becomes: Are the TAC-LP larger or smaller than the costs of storage (complete cycle of loading and unloading).

3.4 Average total cost of intermittent technologies in the context of the Energiewende with several technologies

3.4.1 Analogy to the combined adaptation in production programming

In the context of an energy transition, the question arises of how the expansion should occur over time with multiple possible energy sources available. As previously mentioned, statistical analyses for the target year 2050 do not show this path.

To answer this question, the theory of production planning in industrial management can be used as a starting point. This approach provides a theoretical model of how a company that has 2 (or more) machines, which can manufacture the same product but that have different cost functions, can be used cost effectively. The procedure is known as combined adjustment.

Figure 8: shows the transfer for the issue evaluated here.[11] In direct analogy to the combined adjustment, the solution would be as follows:[12]

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[11] This means that the TAC of the last plant are addressed and not the margin costs of production for the combined adjustment.

Phase 1: Expand the technology with the lowest TAC-LP up to the point where these costs rise.

Phase 2: Continue to expand this technology until its TAC-LP reaches the level of the TAC-LP of the next most expensive technology.

Phase 3: Expand the next more expensive technology until its TAC-LP rise (note that cost curve of the respective technology depends on the result in Phase 1 and 2, more details in the following section).

Phase 4: Expand both technologies so that the TAC of the most recent plants rise uniformly.

Taking into account the information at the end of Section 3.3, it should be noted here that it makes sense during Phase 2, i.e. with rising costs of the less expensive technology, to check the use storage. The use of storage for more expensive technology does not, on the other hand, make sense with a view of the cost of the overall system.

Based on this approach, it is now already possible to see that focusing on onshore wind energy could provide a cost-efficient development path compared to other technologies.

Critics of this approach might argue that the other technologies – in particular photovoltaics – still have a large cost reduction potential in the future (see Figure 2), which must be taken into account in the analysis. [13] This question is addressed later, first another aspect is illuminated.

The analogy to production planning seems obvious. However, the problem in the context of an energy transition has different characteristics, as shown in the following.

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[12] The attentive reader who suspects a mistake here, should note that the actual non-applicability of the direct analogy is explained in the next section.

[13] It should be noted here briefly that the cost reduction potential is a function of the output, and is thus purchased through the construction of more expensive plants. The decision, which proportion of the capacity should (continue) to be built in Germany, is a political one.

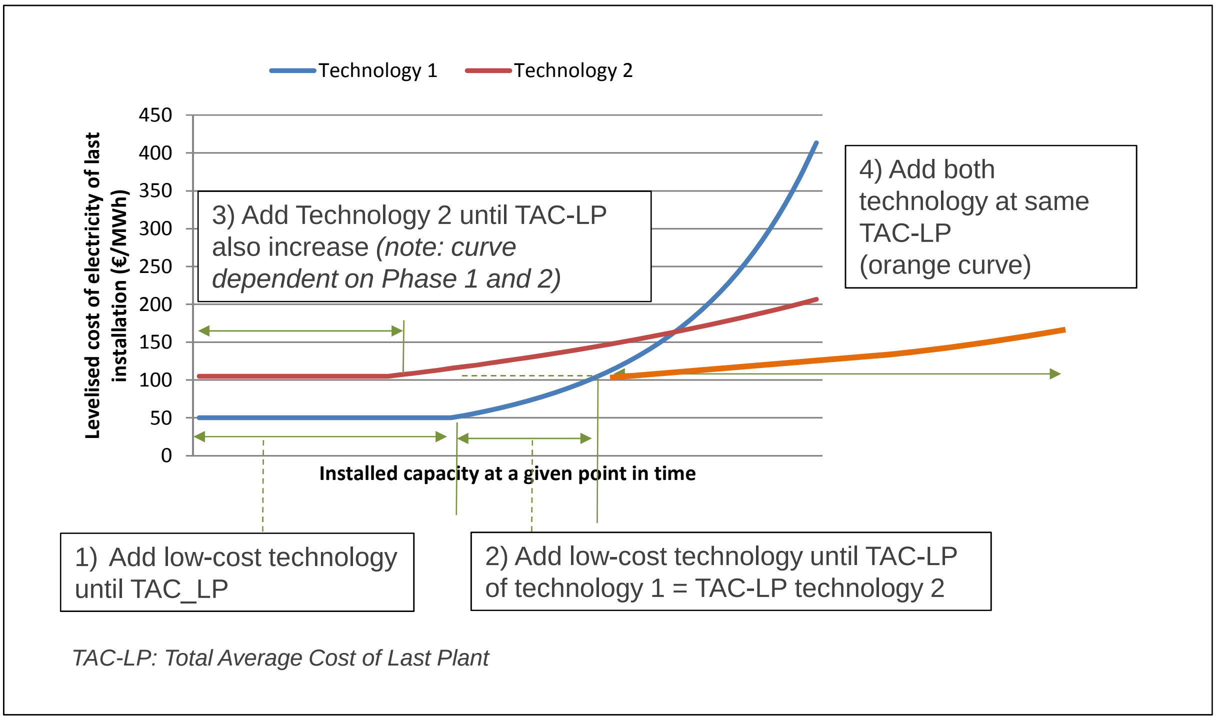

Figure 6: Cost-efficient development path of two intermittent technologies with independent evaluation of the respective cost curves

3.4.2 Combined adjustment in the context of the energy transition

The cost curves of the individual technologies are not, as opposed to the costs of two machines in a production planning scenario, independent of one another: With the expansion of the one technology, the residual load curve changes and thus with it also the potential for direct use of the feed-in of the other technology, thus moving its cost curve.

The example of the previously used load and feed-in curve of a day in May illustrates the topic. Figure 7 displays in addition to the load and feed-in curve for onshore wind energy (left) also the analogue graphic for photovoltaics (right). In the example it would now be possible, with an independent evaluation of the technologies, to expand PV up to level 3 without causing surpluses and thus higher costs.[14] In actual fact, however, the cost curves are not independent of one another. With the expansion of onshore wind energy, e.g. to level 2, the (residual) load curve and thus the cost curve changes for photovoltaics. Taken on its own, the installed capacity of PV at level 3 would not lead to a surplus (i.e. 100% use would be possible). For combined analysis, however, significant surpluses result (compare the red ellipses in Figure 7).

[14] In photovoltaics, the problem described can already be seen at the local level. See the rules for limiting power and the obligation for ripple control signal capability or the discussion (and actual requirement) of batteries as storage.

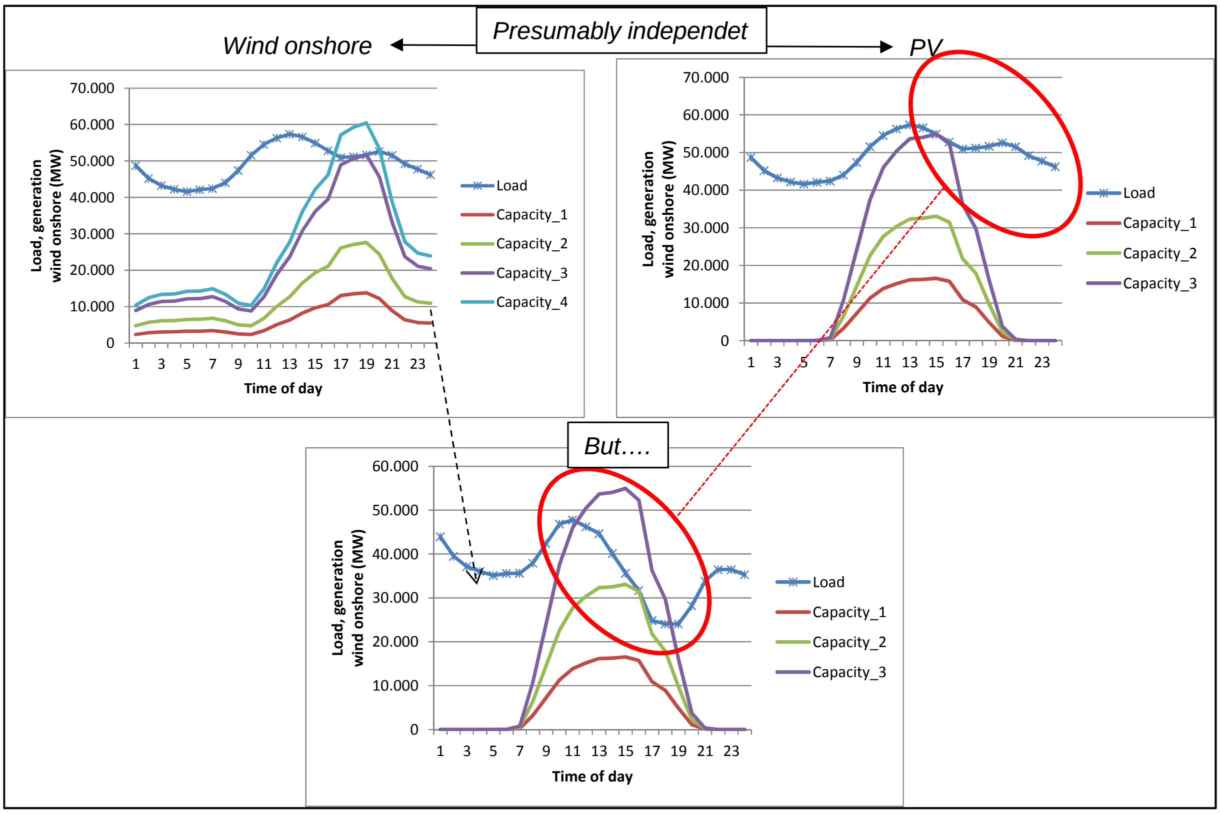

Figure 7: Dependence of the residual-load curve for the evaluation of potential for photovoltaics on the expansion level of onshore wind energy

The results have several implications:

a) After the feed-in with wind energy, the installable PV capacity drops for electricity that can be used directly.

b) With maintaining level 3 for PV, TAC of the directly usable quantity of energy (of the last PV plant) rise, which in this case increases the costs for the use of electricity from these plants and thus the system costs.

c) With a view toward optimising the overall system, the higher costs from b) imply an initial further expansion of wind energy to the level of new TAC of the last PV plant.

d) Depending on the costs, load and feed-in curves, a-c can repeat any number of times. The result of the cost minimisation can fundamentally differ from those of the independent evaluation of the technologies.

4 Marginal costs of the energy revolution: numerical analysis for Germany

After presenting the methodological framework in the previous section, a numerical analysis is performed. It focuses on the question of a cost-effective development path with a view toward onshore wind energy and photovoltaics. It is exactly there that there is a need for decision making in the context of the current electricity price discussion and the next Bundestag election.

4.1 Analysis with current costs

For the load curve as well as for wind power and photovoltaics, the feed-in profile from 2011 is used. To calculate the residual load, the installed capacity of wind power and PV from 31 December 2012 was selected. The analysis is performed in accordance with an hourly resolution, i.e. there are 8760 hours per year to be considered.

Biomass and hydropower as supply-independent technologies are not taken into account. Electricity storage was not investigated as well. It is assumed here that for the evaluation of the cost-efficient development path, storage is not relevant. Both technologies have as an output the same physical electricity, which would need to be stored. It is therefore assumed that the cost of storage is not dependent on whether the electricity comes from wind power or PV plants.[15] Load management is also not considered.[16]

Finally, network bottlenecks are neglected that actually exist today at the local level.

The "theoretical" electricity production costs and related relevant assumptions are described in Table 1. In this case "theoretical" refers to the fact that for the calculation it is assumed that the entire quantity of electricity can be used directly without additional cost. The costs are thus on the same order of magnitude as today's values (see also Figure 2).

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15 The assumption must still be verified. The storage costs also depend on the loading and unloading capacity, and thus from the feed-in curves. One hypothesis is that the cost of storage for surplus electricity from photovoltaics is greater.

16 Storage and load management are both also not available in greater quantities in the short term (in the next few years).

The costs are assumed to be independent of location for all plants.

Table 1: Assumptions for the calculation of the costs

	LCOE (€/ kWh)	*LCOE (€/ MWh)*	Investment cost (€/kW)	Lifetime (years)	WACC	Maintenance cost (fix) (€/(kW*a)	Fixed cost / year (€/kW)	Full load hours
Wind onshore	0,065 €	*64,61 €*	1.200 €	20	5%	20 €	116,3 €	1.800
PV	0,126 €	*126,43 €*	1.500 €	25	5%	20 €	126,4 €	1.000

Figure 8 shows the development of the total average costs of directly usable electricity levels of the last plant for independent analysis of the addition of wind power or photovoltaics. For both technologies, there is initially a certain amount of addition capacity that can be added at constant TAC-LP. As further capacity is installed for these technologies, however, the costs rise. It can be seen that the slope of the cost curve for photovoltaics is greater than for onshore wind energy. This is attributable in particular to the fact that photovoltaics can systematically only be fed in during the day, and thus the construction of additional capacity generates greater and greater surplus during the day, a surplus that cannot be used directly.

Considering the above phase model and for independent evaluation of the technologies, a development path would result such that in phase 1 and 2 initially approximately 122 GW of onshore wind energy could be added before the TAC-LP of the wind plants would reach the level of photovoltaic plants (approx. 126 €/MWh see Table 1, see green lines in Figure 2).

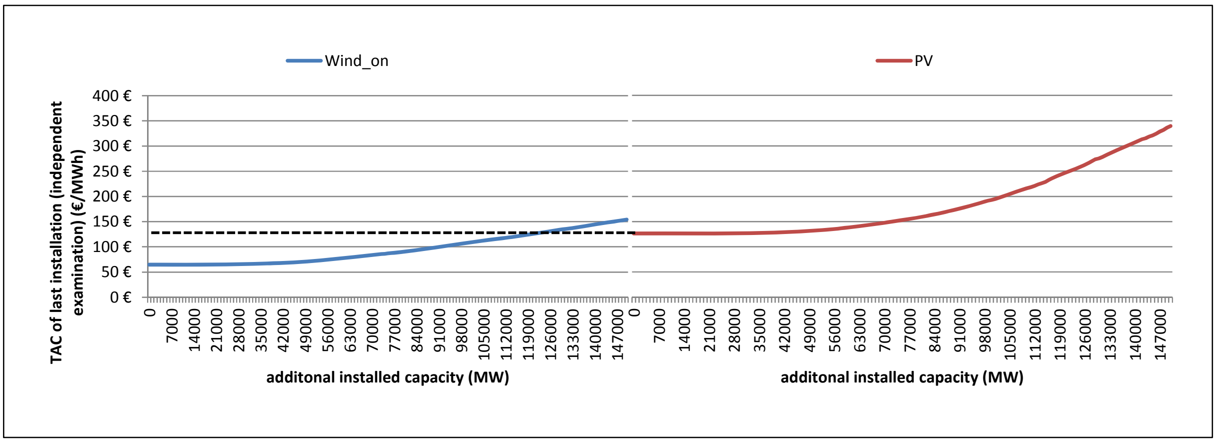

Figure 8: Total average cost (TAC) of directly usable energy from additional capacity of onshore wind power and PV in Germany (feed-in and load profile from 2011; installed wind and PV capacity for starting point: 31.12.2012; costs see Table 1)

As shown above, however, the technologies cannot be evaluated independently of one another. With the expansion of onshore wind energy by 122 GW, the relevant residual load curve changes radically. (This was depicted graphically in Figure 7 for an individual day. See also attachment for a more detailed illustration.) With added capacity, the TAC-LP rise due to the changed residual load curve for additional new photovoltaic plants. These are then around 160 €/MWh, meaning that additional onshore wind energy can continue to be built. Several iterations demonstrate that it takes an additional installed capacity of approximately 175 GW of onshore wind energy before the two technologies have the same TAC-LP. This value lies around 180 €/MWh. It should be noted here that the costs given for the directly usable quantity of electricity of the last plant do not correspond to the actual expected electricity costs for the consumer. Instead, they represent an upper limit for a situation in which no storage is possible. The actual total average costs will thus be lower than this value, as storage will be used.

In considering which of the two technologies should be expanded over the coming years, a significant result is thus obtained. In practice, the planned addition of installed capacity should be checked regularly during the coming years (see for example Bode & Groscurth 2011)

Figure 9 illustrates the cost curves for the additional development starting from this point (i.e. after the addition of 175 GW of onshore wind energy), providing information for the starting point of phases 3 and 4. Please note with regard to the figure: The cost curves are shown for an independent expansion of the respective individual technologies. It is not the simultaneous expansion at same TAC-LP.)[17]

[17] For readers interested in methodology, additional results are given in the appendix with regard to phases 3 and 4.

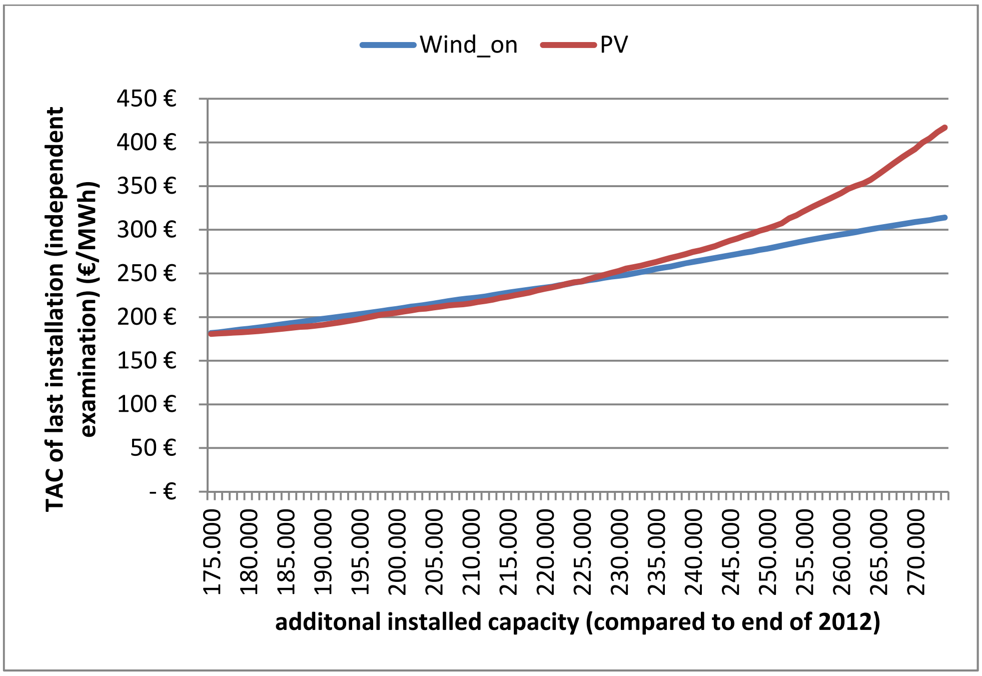

Figure 9: Average total cost (TAC) of directly usable energy in the development of onshore wind power in Germany with independent[18] evaluation after an addition of 175 GW of onshore wind energy (feed-in and load profile from 2011; installed wind and PV capacity as of 31.12.2012; costs see Table 1)

4.2 Interim conclusion

Under the aforementioned assumptions, the presented approach for determining the cost-effective development path for onshore wind energy and photovoltaic results in the following path:

First add approximately 175 GW of onshore wind energy and only thereafter add photovoltaic plants together with wind energy.

The following arguments can be brought up to counter this conclusion:

1. There is not sufficient potential for onshore wind energy
2. It will take too long
3. The cost of photovoltaics will continue to fall
4. The effect on the existing and necessary back-up conventional plants has been neglected
5. The role of storage was not sufficiently discussed

[18] For a better understanding of "independent" see Figure 8. Either wind onshore or PV is added. To allow for a comparison of the two cost curves they are depicted in one diagram.

4.2.1 The potential for onshore wind energy

The potential for onshore wind energy is influenced by various factors, such as the cost of capital, site quality, etc. In addition the willingness of local communities to accept wind farms affects the overall potential. Table 2 shows possible installable capacity. Resistance from the local population was anticipated in that study by limiting land use to 2%. The previously calculated additional construction of approximately 175 GW in addition to the existing approximately 30 GW at the end of 2012 would thus be possible.

One may argue that the LCOE generation of wind onshore will increase with higher capacity since more and more site with unfavourable wind conditions might be necessary. This might be partly true. However, already today one can see in Germany that a) increase of capacity does not follow the rule "best sites first" given local resistance for high plant penetrations and b) the EEG explicitly subsidises plants in areas with more unfavourable conditions.)[19]

Table 2: Energy and capacity potential when using 2% of the German land (source: F-IWES 2011, p. 18)

Maximum Potential (areas without restrictions)	Full load hours	Use of 2 % of potential areas	
		Power (GW)	Yield (TWh)
722	2071	189	390

4.2.2 Duration of the Energiewende

The expansion of onshore wind energy recently stood at about 2,500 MW per year. To add another 100 GW at the same rate would thus require 40 years. This could be too slow for some parties. However, for an increase in the expansion rate, it should be ensured that the "same mistakes" are not repeated that were made with photovoltaics.[20]

4.2.3 Falling costs of photovoltaics

In the above depiction of the possible development of photovoltaic costs (see also Figure 2) the importance of cost reduction due to the expansion itself was noted (the "learning curve"). In this respect, one could argue that with the suggested focus on onshore wind energy, this cost reduction potential is nullified. This may in part be true. Relevant here is the proportion of the expansion of the PV plants in Germany compared with the global increase in installed capacity. When the proportion in Germany is lower, the cost reduction is less

[19] Still, future work can draw more attention on this issue.

[20] What is meant here is permitting an initially uncontrolled expansion, which can then only be slowed with great effort.

dependent on the increase in German capacity, allowing Germany to profit for this reduction as a price taker.

When the increase in installed capacity in Germany represents a high proportion of the world market, the opposite holds. A decision not to expand PV in Germany would slow down the global reduction in cost. In this case, it would need to be a political decision how much additional cost the electricity consumers in Germany should bear to drive the cost reduction of PV plants at the global level.

Independent of this decision, in the following the cost-efficient development path is analysed under the assumption that the costs for PV would be already significantly lower today. Taking Figure 2 into consideration, the following assumptions are made.

Table 3: Cost scenario 2

	LCOE (€/ kWh)	*LCOE (€/ MWh)*	Investment cost (€/kW)	Lifetime (years)	WACC	Maintenance cost (fix) (€/(kW*a)	Fixed cost / year (€/kW)	Full load hours
Wind onshore	0,065 €	*64,61 €*	1.200 €	20	5%	20 €	116,3 €	1.800
PV	0,080 €	*80,31 €*	850 €	25	5%	20 €	80,3 €	1.000

With costs of approximately 80 euro/MWh for all new PV plants, an optimistic scenario is selected. The specified forecast (see Figure 2) assumes significantly higher costs for small plants in the year 2030.

The methodology is identical to the one described above. It turns out that even assuming significantly lower costs for new photovoltaic plants, the cost-effective development path would first require a focus on onshore wind energy. The expansion target would then be about 80 GW of additional wind capacity. Only then will photovoltaics become relevant.

4.2.4 The repercussions on conventional plants

Since the feed-in curves for different intermittent renewable vary on from another the resulting residual load curve depends on the technology, too. This in turn may have two consequences. Depending on the renewable technology used:

1. the necessary maximum back-up capacity may change
2. the value of the existing power plants may change with different residual load curves as the full load hours of these plants declines.

Ad 1)

The rationale behind this argument is that wind and PV complement one another: While wind produces less in summer PV has its maximum generation at this time. However, this thinking neglects the fact that back-up capacity must be determined based on extreme situations. Historical evidence shows, that "dark dead calms" have been observed in the past at times when load is very high.[21] Maximum back-up capacity must then (almost) equal load and in thus not dependent on the mix of intermittent renewables.

Ad 2)

Already today one can observe that existing conventional plants in Germany suffer from an increase of additional renewable capacity, most importantly from PV which is shaving peak prices. Conventional plants produce less (i.e. LCOE rise) and earn less. However, under the political target of 80% renewables in 2050, the devaluation of existing assets is not relevant for decision. Investment costs are sunk cost. Changes in LCOE of electricity are thus not relevant for the question analysed here (i.e. optimal expansion of intermittent renewables). Only differences in variable costs such as fuel costs are relevant for decision and have to be considered.[22]

4.2.5 The role of electricity storage

The importance of electricity storage in the context of the energy transition is well known and is under intense discussion. As part of the study presented here, the following aspect will be investigated in greater detail:

What impact does possible storage of electricity have on the expansion path of wind power and photovoltaics? The issues of absolute costs, potential, etc. will not be investigated.

Due to local bottlenecks, the use of storage has already been propagated today (especially in combination with PV installations). Figure 10 presents again the rationale for the use of storage in the context of the aforementioned phase model. In the overall system (separate from local bottlenecks) the use of storage must first be evaluated in phase 2, i.e. when the low cost technology generates surplus. The next opportunity will be in phase 3 – details depending on whether or not surplus is generated from the additional capacity of the more expensive technology. Finally in phase 4, i.e. during a possible simultaneous expansion of wind power and photovoltaics. In this phase, one or more options may be economically viable.

- Expansion of wind onshore and PV
- Expansion of wind onshore and PV with storage
- Expansion of wind onshore capacity with storage
- Expansion of photovoltaic capacity with storage

In the light of German renewable energy policy one might think that it makes sense to construct photovoltaic plants with storage if the costs of the electricity use from this system are lower than the TAC-LP of onshore wind energy. This approach, however, neglects one of

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21 More precisely on November evenings dead calms have been observed. PV is not generating at that time by its very nature and wind turbine cannot under such conditions. In winter evenings load is highest in Germany compared to the rest for the year. For more on this see Bode et al. (2011b).

22 This will be subjects of future work.

the alternatives and is therefore a wrong result: Also surplus from additional wind turbines can be used for storage. A full comparison also needs to consider this option. In this case two line of argumentation are possible:

1. Assuming that the storage cost for one kWh of electricity is the same for all plants, in a system in which the "theoretical" electricity production costs of photovoltaic are greater than for onshore wind energy the expansion of onshore wind with storage must always be more economical than the analogous alternative with PV.
2. The costs for storage are not the same as the surplus pattern are different. In this case I would intuitively argue that storage energy surplus from wind energy is economically more attractive since:
    a. Wind surplus patterns are more evenly distributed over the year where PV is peaking in summer (while load in highest in winter in Germany). Storage has thus more cycles and needs less capacity with surplus from wind
    b. Maximum surplus from PV is greater than from wind requiring higher storage load capacity, which is likely to be more costly.[23]

Therefore, the combination of photovoltaics with storage does not per se provide an economical option as currently implied by support programmes for storage systems.

[23] This requires a more detailed analysis in future research.

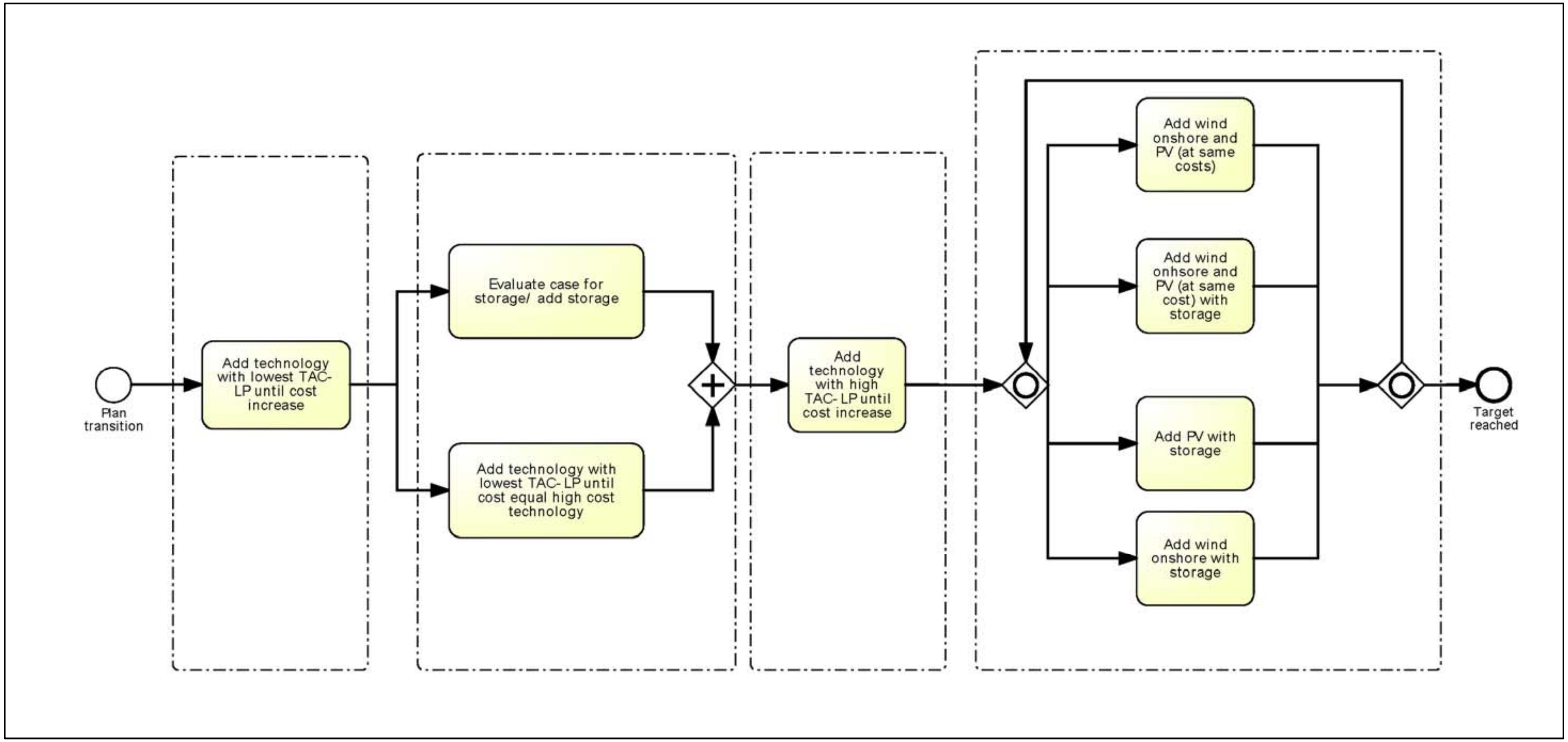

Figure 10: Options for increasing capacity efficiently in the phase model of the energy transition

4.2.6 Integrating the results into the discussion on the development of the Renewable Energy Law

This analysis may initially help provide more attention to the aspect of cost-effective design in the discussion of the electricity price brake and the energy transition.

With regard to the discussion about the development of promotion measures, it can also help elsewhere.

a) With regard to the question whether a new proposal makes possible a cost-effective development path.[24]

b) With regard to the question, such as for instruments that provide for quantity control[25], which quantities should actually be defined.

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[24] For example, an ad-hoc assessment of non-technology-specific feed-in rates (we could call them unisex rates), such as 10 cents/kWh, suggests that here the "actual quantity of electricity to be remunerated" must be determined in much greater detail. Does this address the "theoretical" cost of electricity production? If so, will we thus block off a cost-efficient generation matrix for the future, as long as surplus still exists?

[25] See for example the so-called market-volume model (Bode & Groscurth 2011) or quota models that include a technology differentiation.

5 Conclusion and outlook

In the discussion on the Energiewende, the aspect of a cost-effective development path has so far interestingly only been discussed in passing, if at all. The topic also has not been addressed as part of the so-called electricity price brake presented by Environment Minister Altmaier.

This paper has addressed this issue and proposed a new methodology for identifying a cost-efficient path for expansion on the way to an energy transition.

The focus is not placed on "theoretical" power generation costs of wind or photovoltaic installations as they are used regularly in the discussion. Rather, the approach is based on the following points:

- For one, on the total average costs of the directly usable quantity of electricity of the last installed plant. The reason for using this perspective is the fact that as part of the Energiewende the high levels of capacity of wind power or photovoltaics increasingly lead to surpluses that cannot be directly used, thus generating higher costs.
- At the same time, the paper evaluates the interaction of different intermittenttechnologies (wind power and PV) in the analysis of the electricity production costs: In systems with a high proportion of such technologies, construction of a new, additional plants affect the costs of another further installation of the other technology, as the respective residual-load curve changes, i.e. the remaining electricity demand.

The analysis of electricity production costs in isolation from the corresponding electricity system thus leads to a suboptimal generation mix. The findings may also be relevant in the course of the on-going discussion about changes to the funding regime.

A numerical analysis for the energy revolution in Germany shows, for different cost scenarios, that for a cost-effective development path of renewable energy the focus for the coming years should be placed solely on onshore wind energy (at least an additional 85 GW above the current level). Only after this additional capacity has been installed do windows open up for additional photovoltaic capacity, even when photovoltaic costs are assumed for today that are not expected until the year 2030. Depending on the annual expansion rate of onshore wind energy there should be no further installation of photovoltaic plants for the next 20 to 30 years.

It should be noted here that the costs given for the directly usable quantity of electricity of the last plant do not correspond to the actual expected electricity costs for the consumer. Instead, they represent an upper limit for a situation in which no storage is possible. The actual total average costs will thus be lower than the specified values.

Regardless of this specific configuration, this paper may provide valuable input regarding the cost efficiency in the discussion of the energy transition.

Future analyses will consider the following aspects in greater detail:

- Consideration of cost curves for wind onshore based on possible unfavourable site utilisation with large capacities (increasing costs)
- Consideration of different costs resulting from different residual load curves for wind and PV capacity increases
- Economics of storage in the context of the energy transition
- Integration of offshore wind energy
- Consideration of load management
- Other cost scenarios
- Further feed-in scenarios for wind energy (calm wind years vs. strong winds years)

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ANNEXES:

1) Explanation of interdependencies for different technologies

Figure 11 shows on the left site the TAC-LP curves for wind onshore and PV based on installed capacity in Germany as of 31.12.2012. Wind onshore is cheaper than PV (1). The former capacity can thus be increased until the PV level is reached (2). With increase of wind onshore by an additional 122 MW, the residual load curve and thus the relevant cost curve for PV changes (3). This in turn allows for an additional increase capacity of wind onshore.
After some iteration, TAC-LP are the same for both technologies (see main body of text for details).

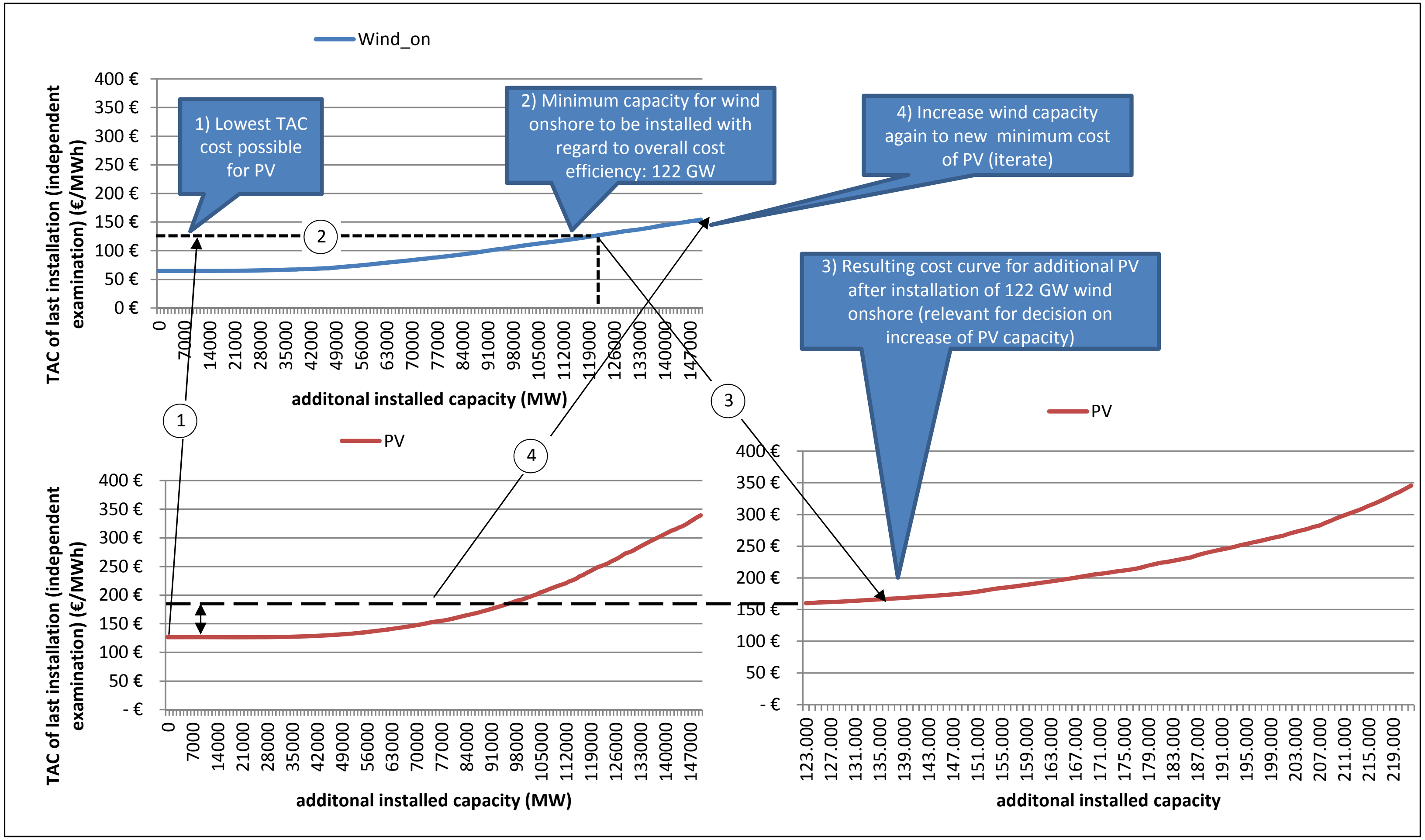

Figure 11: Total average cost (TAC) of directly usable energy from additional capacity of onshore wind power and PV in Germany (feed-in and load profile from 2011; installed wind and PV capacity for starting point: 31.12.2012; costs see Table 1)

2) Capacity increase in Phase 4:

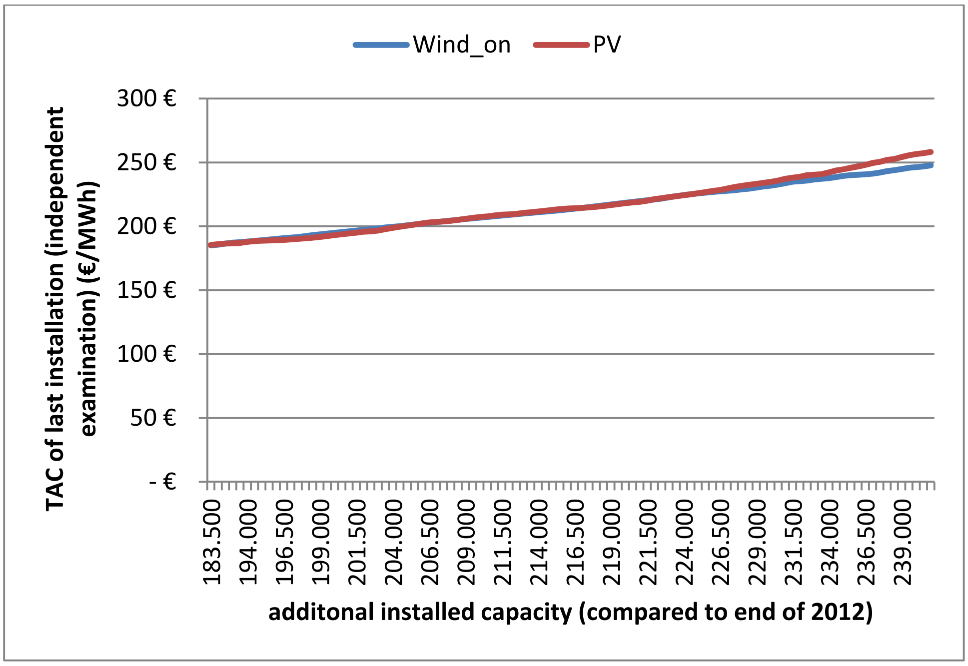

Figure 12: Average total cost (TAC) of directly usable energy in the development of onshore wind power in Germany with independent[26] evaluation after an addition of 183 GW of onshore wind energy (feed-in and load profile from 2011; installed wind and PV capacity as of 31.12.2012; costs see Table 1)

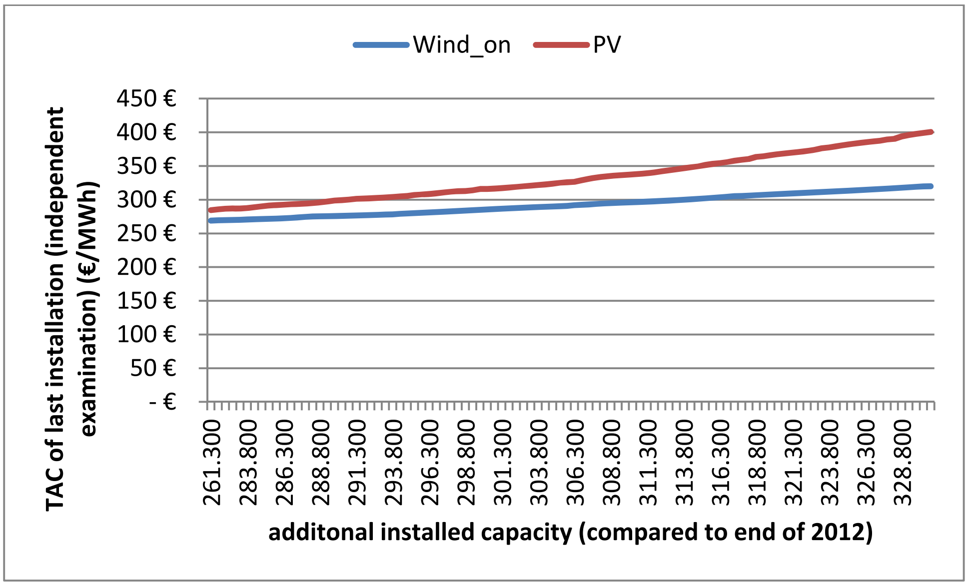

Figure 13: Average total cost (TAC) of directly usable energy in the development of onshore wind power in Germany with independent evaluation after an addition of 261 GW of onshore wind energy (feed-in and load profile from 2011; installed wind and PV capacity as of 31.12.2012; costs see Table 1)

[26] For a better understanding of "independent" see Figure 8. Either wind onshore or PV is added. To allow for a comparison of the two cost curves they are depicted in one diagram.