The Market Value of Fluctuating Renewables

What drives the market value of electricity from fluctuating renewables sources such as wind and solar power?

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- Working paper, comments welcome -

Abstract

The price that electricity generators receive when selling their output to the wholesale market is highly-time variant, because storing electricity is expensive and marginal generation costs vary. This has important implications for the valuation of electricity from fluctuating renewable energy sources (fRES) and makes the analysis non-trivial. High fRES supply in a certain hour shifts the merit-order curve (supply curve) to the right, reducing the equilibrium price. This means, once large capacities of solar and wind power are installed, the electricity price is significantly lowered whenever it is sunny or windy: This is often called the “merit-order effect”. The merit-order effect can be measured by the “value factor”, which is the ratio between average revenue of a generator and the average electricity price during all hours. This paper aims to quantify the merit-order effect and its drivers.

Drawing on historical market data, one can observe that the wind value factor in Germany has been around 0.95, while the solar value factor has been around 1.15. In electricity markets with a lot of flexible hydro reservoir capacity, the value factor is much closer to unity, e.g. in Nordic countries. During the last three years, Germany experienced a boom in solar power, resulting in a decrease of the solar value factor from 1.25 to 1.11, which can be attributed mostly to the merit-order effect.

To understand and quantify what drives the value factor, a calibrated numerical model of the North-Western European electricity market has been developed. The most important conclusion of that work is that the value factor depends strongly on the amount of installed capacity: For example, the German wind value factor drops from 1.1 to 0.4 as the market share of wind power is increased from zero to 41% (it was 6% in 2010). The solar value factor drops as much as the wind factor, despite being better correlated with demand and consequently starting from a higher level.

[1] The findings, interpretations, and conclusions expressed herein are those of the author and do not necessarily reflect the views of Vattenfall. Contact: Lion Hirth, Vattenfall Europe AG, Chausseestraße 23, 10115 Berlin. lion.hirth@vattenfall.com. I would like to thank Peter Kämpfer, Mats Nilsson, Catrin Draschil, and the participants of the DSEM seminar in Berlin for valuable input and comments. The usual disclaimer applies.

1. Introduction

Many European countries have experienced a rapid increase in electricity generation from renewable energy sources (RES) during the last years. According to governmental goals, as expressed in the National Renewable Energy Action Plans, the share of renewables in EU electricity consumption shall reach about 35% by 2020[2], up from 17% in 2008 and 13% in 1997 (Eurostat 2011).[3]

The potential of hydro power being largely exploited and biomass being limited by supply constraints and sustainability issues, much of the future growth of RES generation will need to come from wind and solar power. Solar and wind power are fluctuating or "intermittent" electricity sources (fRES).[4] fRES are non-dispatchable and can generate electricity only at points in time when the supporting primary energy source is available.

The aim if this paper is to estimate the market value of wind and solar power. Two properties of fRES deserve special attention in this context:

- The electricity price on the wholesale markets is time-variant, because a) demand is variable and relatively price-inelastic, b) there is a mix of efficient generation technologies available that differ in there variable costs / fixed costs ratio, and c) electricity storage is very expensive. In most European markets, there is an electricity price for every hour. To estimate the average specific revenue of an electricity generator, one needs to know during which hours electricity was produced. It is not sufficient to multiply yearly production with the average price of electricity, one needs to multiply hourly prices with hourly generation.[5] Generation from fRES is given by their generation profiles.
- The output of fRES is stochastic and thus uncertain. The benchmark electricity price is usually determined day-ahead, that means 12-36 hours ahead of delivery. Deviations between forecasted generation and actual production need compensated for by other generators or load adjustments. Coordination takes place on the intraday market and the balancing market. Solar and wind power generators can sell excess generation on these markets or have to acquire electricity if forecasts were too optimistic. To determine the reduction in value due to uncertainty one needs to understand forecast errors, how they develop between day-ahead gate-closure and time of delivery, and the price behaviour at intraday and balancing markets.

The effect of fluctuations and stochasticity on the market value of fRES can be compared to a dispatchable plant running base load without any unexpected outages. The discount caused by the given generation profile is often called "shaping costs" or "profile costs", the discount caused by forecast errors "imbalance costs". Added together, they can be labelled "intermittency costs".[6] Profile costs are often measured with the "value factor" of a certain technology, which is the ratio of the weighted average electricity price that technology receives and the arithmetic average price over all hours (base price). The value factor is a measure for the valence of electricity from a certain genera-

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[2] Beurskens & Hekkenberg (2011) and ENDS (2010) provide comprehensive summaries of the 27 NREAPs. DG Energy provides the plans in several languages: www.ec.europa.eu/energy/renewables/transparency_platform/action_plan_en.htm

[3] Eurostat, www.appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_ind_333a.

[4] Electricity from run-off-river hydro plants is also intermittent. Electricity from biomass (or any other fuel) features similar „intermittent" characteristics when generated in backpressure combined heat and power (CHP) plants with a fixed heat-to-electricity ratio, where the demand for heat at any point of time determines electricity generation. In backpressure CHP plants it is not the availability of the primary energy source that determines power generation at every point of time, but the heat sink.

[5] While this statement is in principle true for every good, short-term price fluctuations of electricity are stronger than of most other commodities.

[6] In a legal sense, all these are not costs, of course, but rather reduced revenues compared to a benchmark plant.

tion profile or technology (Stephenson 1973). During the last years, the value factor for wind power has been between 0.91 and 0.95 for wind power and between 1.11 and 1.25 for solar power.

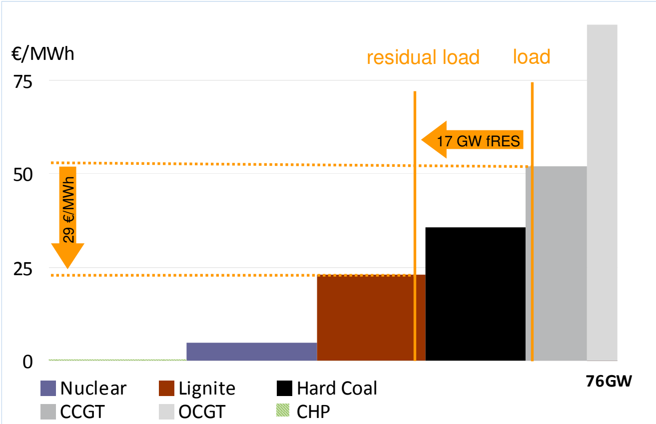

Figure 1: Merit-order curve, load and residual load (solid lines). The estimated equilibrium price at 65 GW load without any fRES generation is 52 €/MWh, the estimated price at the same load and 17 GW fRES generation is 23 €/MWh.

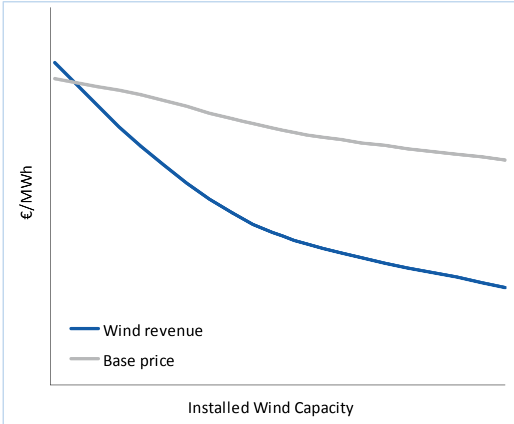

Figure 2: Average revenue of wind power and base price as a function of installed capacity, holding everything else fixed.

This work focuses on profile costs, leaving a closer look on imbalance cost for future research. Thus the title of this paper can be formulated more precisely: What is the market value of wind and solar power on day-ahead electricity markets? Or, from a different perspective: What are the profile costs of fRES?

Wind power revenues are a function of the amount of wind power capacity itself: If there is a lot of wind capacity installed, the large supply of zero-variable-cost power during windy hours drives down the price precisely in those hours when turbines generate much output (figure 1). This implies that the average revenues for a MWh of wind power decreases with more wind power being installed, and it decreases quicker than the base price (figure 2). This phenomenon can be labelled "merit-order effect".[7]

Some might wonder why the market value of fRES is of interest: A feed-in-tariff (FiT) as e.g. implemented in Germany guarantees renewable generators a fixed price for electricity. Thus from an investor perspective, the market price is quite irrelevant since intermittency costs are born by tax payers. However, there are good reasons to study the topic anyway:

- Under a fixed FiT as in Germany, generators receive a fixed price. Ultimately, however, that electricity has to be sold on the market. The difference between the guaranteed price and the market price is a subsidy that has to be financed by taxpayers.[8] To assess how the size of the subsidy evolves one need to know the market price for electricity from fRES.
- Several support schemes, such as a green certificate obligation or a premium-FiT[9], don't guarantee a fixed price for the generator but pay something on top of the market price. Un-

[7] Of course, in any market prices decrease due to increased supply if everything else is hold fixed.

[8] In Germany, small electricity consumers pay a specific tax on electricity that is labelled "EEG-Umlage". That tax finances the subsidy to RES generators.

[9] Countries that use a certificate scheme or a premium FiT include Spain, UK (both the current system and the planned contract for difference), Sweden, Norway, and Poland. Germany will, as Spain, offer a premium FiT to RES generators as an alternative to the fixed FiT starting in 2012. Sensfuss & Ragwitz (2010) discuss shaping and imbalance costs in the context of that change in Germany policy design.

der such schemes, the market value determines directly the attractiveness of fRES to investors.[10]

- More fundamentally, virtually all observers agree that fRES need to be competitive on the market in the long run. Estimating the price that these technologies would earn on the market is crucial to understand if and when technologies become competitive and when support schemes can be expected to be phased out.

There exists some related literature on these topics, both academic publications and policy reports. Joskow (2010) explains the conceptual differences between intermittent and dispatchable generation with respect to welfare and market value. He concludes that levelized costs of electricity (LCOE, full costs), while being often used in practice, are an inappropriate measure to compare dispatchable and non-dispatchable technologies.[11]

Borenstein (2008) estimates the market value of solar power in California. Using 2000-03 market data and a synthetic generation profile he estimates the value factor for solar to be 1.0 – 1.2. Based on a very stylized three-technology price model he concludes that the value factor could rise to 1.5 if price spikes would be allowed. The same model returns a value factor of 1.2 if capacity payments and a price cap are introduced. Borenstein also finds that benefits of distributed solar generation for the distribution network in terms of reduced investment needs or reduced grid losses are non-existent and benefits for the transmission grid are positive but small: they increase the value factor by 0.01.

ISET et al. (2008) and Braun et al. (2008) use a similar model estimate the value of solar power in Germany. They estimate high values, but results are largely driven by drastic assumptions on the CO_2 price (up to 280 €/t). The authors report neither the modelled electricity price nor the value factor. Major methodological issues include an aggregation of the power plant stack to only three technologies and neglecting international trade. Like Borenstein, they find no significant benefits of solar power on the need for grid investments.[12]

Gowrisankaran et al. (2011) develop a numerical model calibrated to south-eastern Arizona, similar to Borenstein's work on California. Electricity prices are not reported, but the average value of a MWh of solar power decreases from 52 \$ to 40 \$ as penetration increases from 10% to 30%.[13] The authors also account for forecast errors, concluding that imbalance costs are around 2.7 €/MWh.

Denholm & Margolis (2007) is the only peer-reviewed publication of the ones discussed here. The authors provide the results of an excel-based calculation of how much solar power had to be curtailed in Texas under different assumptions on solar capacity and must-run constraints. Must-run of conventional generators is assumed for grid stability reasons. For example, assuming a must-run requirement of 35% of annual peak load, if 50% of the consumed electricity should come from solar power, one would need to install so much solar power that about half of all solar energy would need to be curtailed. Their work does not take into account must-run from CHP, imports and exports from the system, no demand elasticity, no wind power, and no kind of storage; prices are not reported. While focusing on spinning reserve requirements, the paper does not provide insights how that constraint could be relaxed.

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[10] This arguments holds only if the certificate price is exogenous to the revenues of wind generators. If the equilibrium certificate price is determined as the gap between full costs and electricity revenues, the revenue levels does not influence total revenues of the generator. However, it is still interesting to understand the revenue development in order to understand certificate price development.

[11] One might add that LCOE are also inappropriate to compare (dispatchable) technologies that have different variable cost and are thus dispatched differently.

[12] The lacking benefits of decentralized solar generation regarding grid costs that are consistently reported by ISET (2008) and Borenstein (2008) make grid fee exemptions for solar (like in Germany) somewhat questionable.

[13] Instead of comparing the value of solar power to electricity prices, Gowrisankaran et al. compare them to the LCOE of a CCGT plant, which is assumed to be 58 \$. If that approach is applied, the value factor decreases from 0.90 to 0.69.

This paper extends the existing quantitative empirical literature in three directions. First, electricity prices are not taken as exogenous. The feedback from fRES generation on prices (merit-order effect) is explicitly taken into account and indeed one main focus of the present work. Second, the cited literature has not paid much attention on the factors that drive the value factor (although some have looked at different CO_2 prices). Here, a larger number of energy system parameters are systematically checked to identify and quantify the crucial drivers of the market value of fluctuation renewables. Finally, the discussed work relied on very stylized models of small isolated geographical areas. Here, a detailed electricity market model is used that covers several European countries. Diverse generation technologies, correlations between demand, wind, and solar generation, international trade, and technical constraints of generation are represented in a detailed manner, and the model is calibrated to historical market data. Endogenous investment in generation, transmission, and storage is accounted for.

Even though significant uncertainties remain when interpreting results of complex modelling, several robust findings emerge. The most importing quantitative finding is presented in figure 3: An estimation of the value factor of wind power as a function of installed wind capacity, at constant fuel and CO_2 prices. The value factor curve is downward sloping, as a result of the merit-order effect. It starts at 1.1 for the first wind turbine, but falls to 0.4 at 100 GW installed wind capacity. The average revenue for a MWh of wind power falls from 70 €/MWh to merely 20 €/MWh. This means that cost reductions need to be two to three times higher than estimated by studies that do not take the merit-order effect into account.

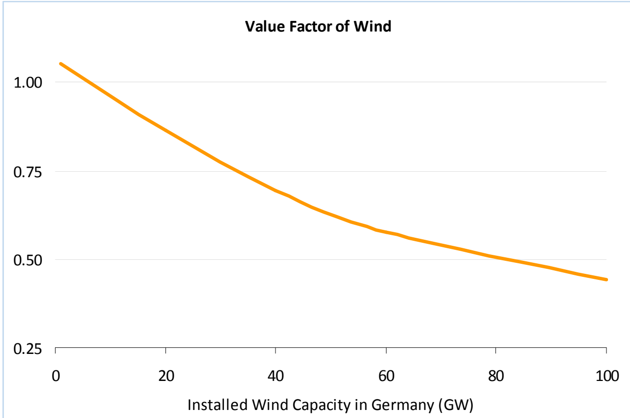


Figure 3: The wind value factor in Germany as wind capacity increase from zero to 100 GW (equivalent to a wind power market share of 41% in North-Western Europe at today's consumption).

Nitsch et al. (2010) envisage 80 GW of installed wind power in Germany by 2050. If that becomes true, and surrounding countries follow a similar growth path, model results indicated that wind generators will on average earn only half the base price.

The fRES value factors are influenced not only by the amount of fRES capacity, but by many parameters of the electricity system, e.g. the CO_2 price, fuel prices, cross-border transmission capacity, and generation flexibility. The numerical model is used to systematically quantify the influence of these parameters. It turns out that effects are sometimes quite surprising at first glance, they are often non-linear and they interact with each other.

A *higher CO_2 price* increases the electricity price, but the wind value factor still drops below 0.5. Even at 75 €/t CO_2, only a few GW of wind capacity would be competitive on the market. *Higher fuel prices* are not necessarily good for wind power revenues: A high gas price induces more investment in hard coal and lignite. That results in a steep merit-order curve and low revenues for wind power because these fuels set the price in windy hours: With higher gas prices wind generators would actually earn less per MWh! The opposite is true for higher coal price. Increasing cross-border *interconnector capacity* is often seen as important and beneficial for fRES. This is not necessarily the case: Higher transmission capacity to France together with large amounts of wind power cause French nuclear becoming often price-setting in Germany during windy hours. Low prices are imported, reducing revenues for German wind power. (The opposite is true for French wind power). One of the most crucial levers to increase the revenues of wind seems to be making the electricity system more *flexible*. Especially important turn out to be combined heat and power producers, which are forced to generate electricity as a by-product during the heating season. Making them flexible, e.g. through the installation of heat storage, could increase the value factor of wind by up to 15 percentage points.

In section 2, historical market data and fRES generation profiles are used to estimate historical value factors of solar and wind power in a few European countries. In section 3, an electricity market model is introduced that is applied in section 4 to estimate the market value of fRES and identify and quantify important drivers. Section 5 concludes.

2. Historical market value

If the historical time series of hourly electricity generation from fRES (generation profile) and the hourly electricity spot prices are known, historical profile costs can be calculated. This is done in the present section for the last years for a few European countries.

The average generation profile of a market area was used for each technology, instead of e.g. a generation profile from a specific wind park. The reason for that is that we are mainly interested in understanding the market value of an average asset and not of an individual project. Generation profiles were derived by taking hourly in-feed over installed capacity. Hourly in-feed data come from the respective TSOs.[14] Installed capacities were taken from TSOs or national statistics and interpolated linearly to derive capacities within the years where only end-of year data were available.[15] Day-ahead price data were taken from various electricity exchanges, namely EPEX-Spot, Nordpool, and APX.

Table 1 shows some aggregated statistics of wind power generation in Germany, namely the average price of year (base price) $\overline{p}$, the average price for electricity from onshore wind power, $\overline{p}^{on}$, and the value factor v^{on}. They are a function of the hourly load factor ℓ_t^{on} and the hourly price p_t.

$$\overline{p} = \frac{1}{8760}\sum_{t=1}^{8760} p_t$$

$$\overline{p}^{on} = \sum_{t=1}^{8760}\left(\ell_t^{on}\cdot p_t\right) \Big/ \sum_{t=1}^{8760}\left(\ell_t^{on}\right)$$

$$v^{on} = \overline{p}^{one} \big/ \overline{p}$$

For example, in 2007, the average revenues if a typical wind turbine on the market would have been 33 €/MWh. The base price in that year was 38 €/MWh. Thus, electricity from wind was worth only 88% of the base price; this ratio is the value factor. One can conclude that the market value for wind power has been constantly below the base price during the last years. The reason for that is mainly the merit-order effect, which was highly significant already in 2007 with 22 GW wind power installed. Comparing the average revenue of 42 €/MWh to levelized costs of electricity from onshore wind in Germany that are at about 80 €/MWh one can see that wind power is still quite far from being competitive on the market. Finally, one can wonder why the value factor has been increasing slightly over the last years, despite installed wind capacity continues to grow. Three potential reasons for that are a) the much flatter merit-order curve (due to a shift in the gas-to-coal-price ratio and CO2 pricing), b) more efficient international trade thanks to market coupling, and c) the impact of solar power that reduces the base price more than the average revenue of wind power.

Table 1: Onshore Wind in Germany

	Base price (€/MWh)	Average Revenue (€/MWh)	Value factor (1)

[14] Statnett, Svenska Kraftnät, Energienet.dk, 50 Hertz, Amprion, TenneT, EnWG, Elia.

[15] This is problematic if new installations are large compared to existing installations at the beginning of a year and construction is not equally distributed throughout the year. German solar is such a case where often much new capacity is installed towards the end of a year, just before tariffs are reduced. For German solar, monthly data were used.

2007	38	33	.88
2008	66	59	.90
2009	39	35	.91
2010	44	42	.94
Average	47	42	.91

Table 2 shows the same market data for solar photovoltaic in Germany. An obvious difference is that electricity from solar would have received a *higher* price than the base price, as indicated by the value factors of 1.11 to 1.25.[16] A second remarkable fact is the strong decrease of the value factor during the last years. That can be traced to the strong increase in installed capacity and already gives some indication of the price-depressing effect of higher deployment rates.[17]

Because most German TSOs publish solar generation data only since late 2010, the solar Generation profile is based on 50Hertz TSO data only. Generation in Germany correlates very well with generation in the 50Hertz area (p=0.93), such that I'm confident in using 50Hertz data as a proxy for Germany.

Table 2: Solar in Germany

	Base price (€/MWh)	Average Revenue (€/MWh)	Value factor (1)
2008	66	82	1.25
2009	39	44	1.14
2010	44	49	1.11
Average	50	58	1.17

Table 3 shows value factors for onshore wind power in Germany, Western and Eastern Denmark, Sweden, and Norway. The countries were chosen because generation profiles were available from the respective TSOs. Value factors are between 0.91 and 1.01 in all countries. One can observe that value factors are highest in the Nordic countries. The Nordic electricity system can be called a "hydro system", since it is dominated by a large share of flexible hydro reservoir generation that features considerable intertemporal flexibility. Consequently Nordic countries feature a quite flat price profile: Usually neither short-term demand fluctuations nor wind fluctuations have a significant impact on the price. Also, the amount of wind power installed in the Nordic is relatively smaller than in Germany or Denmark. The German electricity system is a "thermal system" without significant flexibility to shift generation over time. Thus the price is sensitive to both demand and wind generation fluctuations. Western Denmark is quite well connected to Germany while Eastern Denmark is better connected to Nordic, which explains that here value factors are between those in Germany and Nordic. The market data indicate that hydro systems can absorb fRES generation much better than thermal systems.

Table 3: Value Factors of onshore wind in different countries

	Germany	Denmark-West	Denmark-East	Sweden	Norway
2007	0.88	0.88	0.92	1.03	-
2008	0.90	0.90	0.93	0.97	-
2009	0.91	0.96	1.00	1.01	0.99

[16] Borenstein (2008) reports solar value factors of 1.0 – 1.2 for California.

[17] Solar PV installations grew from 5 GW in 2008 to 9 GW in 2009 and 17 GW in 2010 (end of year).

2010	0.94	0.96	0.99	1.01	1.03
Average	0.91	0.93	0.96	1.01	1.01

3. Model description

The numbers reported in section 2 are point estimates of the value factor of fRES. They show, for example, how much solar power was worth in Germany in 2010, with the specific fuel prices, CO2 price, plant stack, interconnector capacity, demand, market design, and wind and solar installation of that specific year. Furthermore, it is unlikely that the electricity market was in its long-run equilibrium in any of these years, that is in a state where all generators earn their expected return on investment. Thus using these historical numbers for assessments of the future is somewhat problematic. In particular, it is interesting to understand how the value factors change with higher fRES deployment rates.

To evaluate the market value of electricity from fRES under different conditions a calibrated numerical model is needed. A stylized model of the North-Western European electricity market was developed for that purpose. It has the following characteristics:

- It is an integrated dispatch- and investment model that solves the dispatch problem as well as the investment problem in an integrated manner. Capacity is dispatched when the electricity price is above its marginal costs. The existing plant stack is represented as sunk costs; new investments in generation and decommissioning of existing capacity are modelled as endogenous decisions. Capacity is built as long as the sum of hourly contribution margins is larger than fixed costs (including investment costs). Capacity is decommissions if short-term profits are insufficient to cover quasi-fixed costs such as staff and O&M.
- There is no physical representation of the grid; market areas are modelled as copperplates. Cross-border trade between modelled countries is endogenous and limited by net transfer capacities (NTCs). Market area layout is assumed as today. Trade with countries outside the model area is ignored.
- Generation is modelled as discrete technologies, not as individual blocks or plants. Capacities are continuous so that minimum block sizes are not taken into account. Ten technologies are represented in the model: two fluctuating renewables (wind and solar) with zero marginal costs and exogenous generation profiles, seven dispatchable technologies (nuclear, lignite, hard coal, CCGT, OCGT, lignite CCS), a generic dispatchable “load shedding” or “super peak” technology with very high marginal cost and zero fixed costs, and pump hydro storage. Dispatchable plants produce if the price is above variable costs. Storage is optimized endogenously under turbine, pumping, and storage volume constraints. Wind and solar power generation is determined by an exogenous generation profile. Curtailment is possible at zero costs which implies that zero marks a floor for the electricity price.
- Combined heat and power (CHP) generation is modelled as a must-run load by technology. That means that a certain share of the heat-providers lignite, hard coal, CCGT and OCGT are forced to run even if prices are below their variable costs. The remaining capacity of that technology is freely available for optimization. In other words, backpressure generation where the electricity output is limited by heat uptake as well as from reduced electrical capacity due to heat production is ignored. The heat profile is based on ambient temperature. Investments and disinvestments in CHP generation is possible, but the total amount of CHP capacity cannot be reduced. For example, in a high-CO2 price model run lignite CHP is decommissioned and gas-based CHP capacity is built.
- There is endogenous investment not only in generation capacities, but also in flexibility options of the electrical system: The model features endogenous investment in interconnector

(NTC) capacity and pump hydro storage plants. Interconnectors are only allowed between bordering market areas or across the sea. To take into account internal grid investments in the back of interconnectors, the length of interconnectors is assumed from the centre of a market area to the centre of the other. Pump hydro storage is only allowed in markets where today such plants exist.

- The model is linear and does not feature any explicit integer constraints such as start-up cost, minimum load or minimum downtime conditions. Thus it is not a unit commitment model. However, start-up costs are parameterized as run-through discounts to achieve a more realistic bidding behaviour: Baseload plants bid an electricity price below their variable costs in order to avoid ramping and start-ups.
- Ancillary services such as regulating power, voltage support, and short-circuit capacity are not explicitly modelled, either because the model time steps are too long to capture the necessary effects or because the absence of load flow modelling prohibits does not allow explicit modelling. However, it is tried to proxy their effects on dispatch and investment. First, there is a spinning reserve requirement such that during every hour conventional capacity equivalent to 20% of the yearly peak demand has to be online.[18] Pump hydro storage is eligible to provide that service both when pumping and generating, CHP plants that provide heat at that moment are not. Second, flexible assets (OCGT, pump hydro) are assumed to generate 30% of their fixed costs from ancillary services.
- Demand is given exogenous by hour and thus assumed to be perfectly price inelastic. Price elasticity comes in indirectly as the generation technology “load shedding” can be understood as demand response. While abstracting from price-elastic demand in the short-run dispatch decision seems to be plausible, that assumption is somewhat problematic with respect to the investment decision, which takes place at longer time scales.
- The model abstracts from market power, information asymmetry, external effects, irrational agents and other market imperfections. Under these conditions profit maximization of independent firms is equivalent to system cost minimization.
- The temporal resolution of the model is hours and it is solved for a full year. Investment and quasi-fixed costs are implemented through annuities. Intertemporal constraints such as pump hydro storage as well as investment decisions imply that the problem cannot be decomposed in individual time slices, but must be solved at once.
- The model is entirely deterministic and perfect foresight is assumed.
- The model is currently calibrated to North-Western Europe and covers Germany, Belgium, Poland, The Netherlands, and France.
- It is specified as a linear program in GAMS and solved by Cplex. Solving time is about half an hour per run with endogenous investment and a few minutes without investment.
- The most obvious caveat of the model at its current state is the absence of a convincing approach to model reservoir hydro power. In Nordic, France, and the Alps large capacities of long-term reservoir hydro power is available that offers quite some intertemporal flexibility. These hydro reservoirs most probably will play a significant role in determining the market value of fluctuating renewables. For that reason Switzerland and Austria as well as the Nordic countries are not covered; French hydro is proxied by reducing demand during peak hours. Including a good but solvable representation of hydro power will be the next step in model development.

[18] Gowrisankaran et al. (2011) use a 35% spinning reserve requirement.

Equations (1) to (8) give a mathematical representation of the model. (1) gives the energy balance. (2a) – (2b) are the generation constraints for fRES and dispatchable generators. (3a) – (3d) are CHP-related constraints. (4a) – (4b) are the constraints on international trade. (5) is the must-run spinning reserve constraint. (6a) – (6c) are storage-related constraints. (7) is the cost equation, which is the objective function that is minimized.

$$(1)\qquad l_{t,r} \le \sum_i g_{t,r,i} - \sum_{rr} x_{t,r,rr} + \eta \cdot s^o_{t,r} - s^i_{t,r} \qquad \forall t,r$$

$$(2a)\qquad g_{t,r,j} = \left(c^0_{r,j} + c^{inv}_{r,j}\right)\cdot p_{t,r,j} \qquad \forall t,r,j \in i$$

$$(2b)\qquad g_{t,r,k} \le c^0_{r,k} + c^{inv}_{r,k} - c^{dec}_{r,k} \qquad \forall t,r,k \in i$$

$$(3a)\qquad g_{t,r,h} \ge \kappa_{r,h} \cdot p_{t,r,chp} \qquad \forall t,r,h \in k$$

$$(3b)\qquad \sum_h \kappa_{r,h} = \sum_h \kappa^0_{r,h} \qquad \forall r$$

$$(3c)\qquad \kappa_{r,h} = \kappa^0_{r,h} + \kappa^{inv}_{r,h} - c^{dec}_{r,h} \qquad \forall r,h$$

$$(3d)\qquad \kappa^{inv}_{r,h} \le c^{inv}_{r,h} \qquad \forall r,h$$

$$(3e)\qquad \kappa^{dec}_{r,h} \le c^{dec}_{r,h} \qquad \forall r,h$$

$$(4a)\qquad x_{t,r,rr} = -x_{t,rr,r} \qquad \forall t,r,rr$$

$$(4b)\qquad x_{t,r,rr} \le \overline{x}^0_{r,rr} + \overline{x}^{inv}_{r,rr} \qquad \forall t,r,rr$$

$$(4c)\qquad x_{t,rr,r} \le \overline{x}^0_{rr,r} + \overline{x}^{inv}_{rr,r} \qquad \forall t,r,rr$$

$$(4d)\qquad \overline{x}^{inv}_{rr,r} = \overline{x}^{inv}_{r,rr} \qquad \forall r,rr$$

$$(5)\qquad \sum_k g_{t,r,j} + \eta \cdot s^o_{t,r} - s^i_{t,r} \ge 0.2 \cdot \max_t\left(l_{t,r}\right) \qquad \forall t,r$$

$$(6a)\qquad s^{vol}_{t,r} = s^{vol}_{t-1,r} - s^o_{t,r} + s^i_{t,r} \qquad \forall t,r$$

$$(6b)\qquad s^i_{t,r}, s^o_{t,r} \le \overline{s}^{io}_r + \overline{s}^{io,inv}_r \qquad \forall t,r$$

$$(6c)\qquad s^{vol}_{t,r} \le \overline{s}^{vol}_r + 8 \cdot \overline{s}^{io,inv}_r \qquad \forall t,r$$

$$(8)\qquad C = \sum_i \sum_r \Big(c^{inv}_{r,i} \cdot \left(C^{inv}_i + C^{qfix}_i\right) + c^0_{t,r,i} \cdot C^{qfix}_i + \sum_t g_{t,r,i} \cdot C^{\mathrm{var}}_i$$
$$+ \sum_r \overline{s}^{io,inv}_r \cdot C^{sto}_i + \sum_{r,rr} \overline{x}^{inv}_{r,rr} \cdot C^{NTC}_i \Big)$$

$l_{t,r}$	load at time t in region r (parameter)
$g_{t,r,i}$	generation by technology i (variable)
$x_{t,r,rr}$	exports from region r to rr (variable)
$s^{o}_{t,r}$	storage output / generation (variable)
$s^{i}_{t,r}$	storage input / pumping (variable)
η	storage cycle efficiency (parameter)
$c^{0}_{t,r,i}$	existing capacity of generation technology i (parameter)
$c^{inv}_{t,r,k}$	new investments in capacity of dispatchable technology k (variable)
$c^{dec}_{t,r,k}$	decomissioned capacity of dispatchable technology k (variable)
$p_{t,r,j}$	generation profile for fRES technology j (parameter)
$\kappa_{t,r,k}$	electrical generation capacity of CHP - technology h (variable)
$\kappa^{inv/dec}_{t,r,k}$	new / decomissioned CHP investments in h (variable)
$p_{t,r,CHP}$	generation profile for CHP plants (parameter)
$\bar{x}^{0}_{r,rr}$	NTC value of existing interconnector (parameter)
$\bar{x}^{inv}_{r,rr}$	NTC value of new interconnector investment (variable)
$s^{vol}_{t,r}$	stored energy (variable)
$\bar{s}^{io}_{t,r}$	storage generation capacity / turbine constraint (parameter)
$\bar{s}^{io,inv}_{t,r}$	new storage generation capacity (variable)
$\bar{s}^{vol}_{t,r}$	storage volume constraint (parameter)
C	total annulized system costs (variable)
C^{inv}_{i}	annualilzed investment costs of tech i (parameter)
C^{qfix}_{i}	annualilzed quasi - fix costs (parameter)
C^{var}_{i}	specific variable costs (parameter)
$C^{storage}_{i}$	annualilzed fix cost of storage (parameter)
C^{NTC}_{i}	annualilzed fix cost of $i$nterconnectors (parameter)
t	time step (index)
r, rr	region (index)
i	generation technology (index)
j	renewable generation technology (index)
k	dispatchable generation technology (index)
h	CHP generation technology (index)

The most important technological input parameters are show in table 4. Obviously costs and efficiency vary widely between specific projects, over time, and across space. Cost relations are displayed in figure 4 and 5.

Table 4: Cost parameters of generation technologies.

			investment costs (€/KW)	quasi-fixed costs (€/KW*a)	variable costs (€/MWh$_e$)	fuel costs (€/MWht)	CO2 intensity (t/MWht)	efficiency (1)
Dispatchable		Nuclear*	3350	50	2	3		0.33
	CHP Technologies	Lignite*	2200	30	1	3	0.45	0.38
		Lignite CCS*	3500	140	2	3	0.05	0.35
		Hard Coal*	1600	25	1	12	0.32	0.39
		CCGT	1000	12	2	25	0.27	0.48
		OCGT**	600	7	2	35	0.27	0.30
		Load shedding	-	-	-	1000	-	1
fRES		Wind	1300	25	-	-	-	1
		Solar	2000	15	-	-	-	1
		Pump Hydro**	1500	15	-	-	-	0.70

* Base-load plants are assumed to bid into the market at a discount on their variable costs to capture start-up costs.
**The most flexible technologies OCGTs and pump hydro storage are assumed to earn 30% of their investment cost from other markets (e.g. regulating power). The capex requirement for the spot market is thus reduced by 30%
Source: Estimates based on large set of academic and industry sources, databases and textbooks.

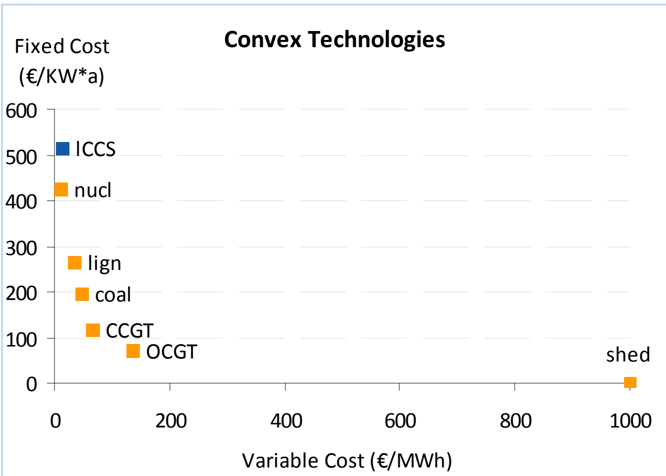


Figure 4: Technologies in the fixed-costs / variable-cost space. Lignite CCS is part of the convex set of technologies: It is dominated by Nuclear.

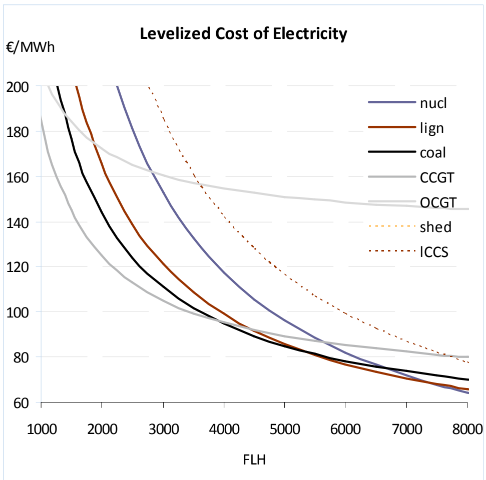


Figure 5: LCOE of all technologies. Load shedding is the cheapest technology for up to 80 FLH.

The generation profiles for wind and solar for 2010 were taken from TSO data where possible (see section 2). For France, forecast data were used and the Polish generation profile was assumed to be the same as the one in the 50 Hertz TSO area. The Dutch profile was assumed to be identical to one in Belgium. Using empirical wind profiles has several benefits compared to synthetic profiles that are widespread in the literature: Most importantly, correlations over time and across space as well as with other time-variant parameters (solar radiation, temperature, load) are captured in a realistic way, since those time series were taken from the same year. Also the effect of geographical smoothening of many widely dispersed generation units within one market is taken into account correctly.

However, one of the drawbacks is that e.g. the German and the Danish profiles are based on an old fleet of turbines while e.g. Belgium turbines are relatively new. To compensate for that all wind profiles have been scaled to 2000 FLH. That means, differences in wind resources are not captured by the model.

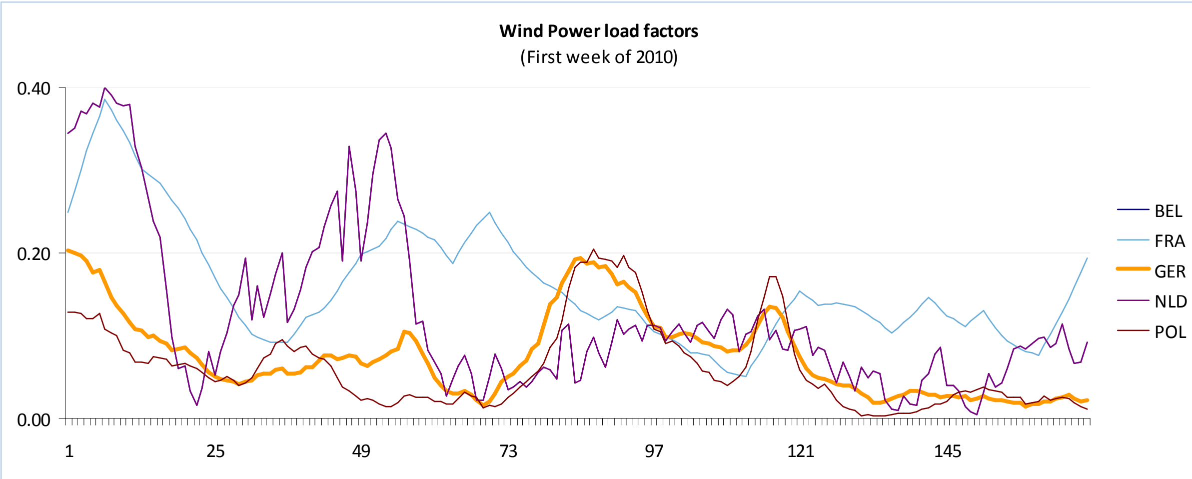


Figure 6: The wind profile for several countries.

Table 5: Coefficients of correlation between hourly wind profiles in 2010.

	wGER	wPOL	wSWE	wNOR	wDKW	wDKE	wBEL	wESP
wGER	1.00							
wPOL	0.94	1.00						
wSWE	0.37	0.38	1.00					
wNOR	0.09	0.08	0.28	1.00				
wDKW	0.53	0.46	0.63	0.09	1.00			
wDKE	0.65	0.62	0.64	0.08	0.80	1.00		
wBEL	0.43	0.29	0.15	0.13	0.18	0.20	1.00	
wESP	0.08	0.04	-0.04	0.08	-0.03	0.03	0.18	1.00

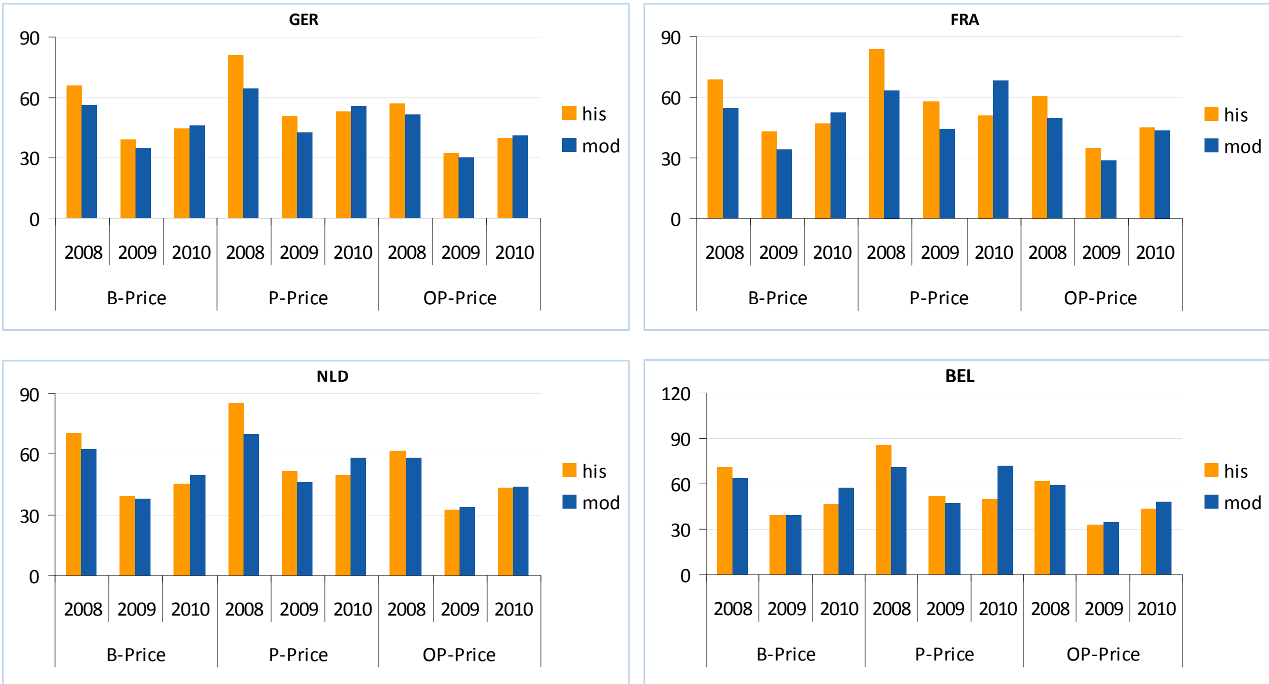
Source: Actual in-feed in 2010 as reported by TSOs. For Poland, German 50 Hz data were used.

As a next step, it is planned to estimate solar and wind generation profiles from weather data. Power curves, which describe the functional relationship between wind speeds and wind power generation (or solar radiation, temperature, and solar power generation) were estimated empirically in order to derive aggregated power curves (appendix). While this approach features several advantages, weather data availability has prohibited the use for the current study so far.

The calibration approach is described in the following paragraphs. The model was tested and compared to 2008, 2009, and 2010 market prices. As input for all years the same power plant stack was used. Investment and disinvestment in generation, transmission and storage was turned off. For each year, wind, solar, and load profiles as well as yearly fuel and CO2 prices were used.

For several reasons, one shouldn't expect the model to hit historical patterns exactly. First, fluctuations of input prices during a year were ignored. Second, seasonal patterns of planned outages as well as unplanned outages of generation and transmission equipment are not modelled. Third, the model assumes market coupling that was only introduced on most of the included borders in late 2010. Forth, international trade at the edge of the modelling area are ignored. Finally, the CHP profile is not year-specific and does not capture correlation between CHP and load or wind generation.

On top of that come all model shortcomings that were already mentioned, e.g. the absence of several technical constraints. Figure 7 shows yearly base, peak, and off-peak prices in four countries. Modelled peak-prices are somewhat lower than historical prices, but in general the model seems to replicate the crucial price drivers of the electricity market quite well. Table 6 reports value factors for wind and solar in Germany and compares them with market data. Modelled value factors for wind are very close to observed value factors. Solar value factors are on a lower level, but show the same decreasing behaviour with increasing capacity. Overall, results give some confidence to use the model for analysis of the market value of fRES.



Figures 7a-7d: Base, peak, and off-peak prices for Germany, France, The Netherlands, and Belgium in €/MWh. Comparison of historical spot day-ahead prices (orange) with model output (blue).

Table 6: Value factors in Germany

	Wind		Solar	
	model	market	model	market
2008	0.93	0.90	1.04	1.25
2009	0.95	0.91	1.03	1.14
2010	0.94	0.94	0.98	1.11

4. Model Results

The electricity market model that was introduced in section 3 is now used to estimate spot market revenues for solar and wind power and derive value factors. Due to space constraints, results are reported only for Germany, results for all other countries are available upon request from the author. The first set of runs is based on best-guess long-term ("benchmark") assumptions regarding energy system parameters. These parameters are then systematically changed to understand their impact on the market value of fRES. The benchmark assumptions are:

- CO_2 price of 20 €/t
- hard coal price of 12 €/MWh (130 €/t) and gas price of 25 €/MWh (as reported in table 4)
- fRES capacity is distributed to all countries (proportionally to their electricity consumption)
- interconnectors have today's NTC values (endogenous investment is possible)
- today's amount of pump hydro storage is available (endogenous investment is possible)
- spinning reserve and CHP must-run constraints hold
- there is an energy-only price (no capacity market)

For this set of parameters (and each set of changed parameters) five model runs were conducted. The model runs differ in the amount of wind power that is assumed exogenously: no wind power, 20 GW, 40 GW, 60 GW, and 100 GW in Germany (and an equivalent amount in the other countries). 100 GW of wind power in Germany corresponds to 280GW in the model region, generating 41% of the 2010 electricity consumption. (Dis-)investment in other generation technology as well as interconnector capacity and storage is endogenous to the model.

Figure 10 and 11 present the results from the benchmark run and represent the central results of this study. With little wind power installed, the value factor is above unity, implying that the first wind turbine in Germany would have earned a price higher than the base price. The value factor drops quickly as installed capacity is increased and falls below 0.5 at 80 GW.[19]

Nitsch et al. (2010) project that 80GW of wind power are installed in Germany by 2050. According to the model results, that implies that the average revenue of wind generators is then only half of the average electricity price!

The availability of zero-marginal cost wind power also depresses the base price, as show in figure 11. With wind penetration growing from 0 to 100 GW, it falls from 65 €/MWh to 48 €/MWh. As indicated by the decreasing value factor, revenues of wind generators fall much stronger, from 68 €/MWh to 21 €/MWh. That implies that at 100 GW installed wind capacity levelized cost of wind power would need to drop to 21 €/MWh for wind to become competitive on the market.

The dotted line in figure 11 gives a very rough idea of cost development under learning. Assuming costs as reported in table 4 and 2000 FLH today's LCOE of onshore wind power are about 70 €/MWh.[20] A learning rate of 5% is assumed, that means LCOE are reduced by 5% each time global capacity doubles. Doubling of global capacity is assumed to take place twice as much as doubling of German capacity. This results in a cost drop to 52 €/MWh at 100 GW installed. One can see that the gap between costs and revenues remains open, and indeed increases. If the LCOE of wind fell to 50 €/MWh, about 20 GW of wind power would become competitive. The LCOE need to drop 30 €/MWh to make 60 GW competitive and to 20 €/MWh to make 100 GW competitive. From a different perspective, with a value factor of 0.4 and LCOE of 52 €/MWh, the base price has to be above 130 €/MWh to make wind competitive.

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[19] The value factors between 20GW and 30GW are in the range of 0.8, while both market data and model back-testing reported value factors above 0.9. This is because here similar penetration rates in all countries have been assumed, while in the calibration there was relatively less wind outside Germany.

[20] Compared to literature estimates, this is already a quite optimistic (low) figure,

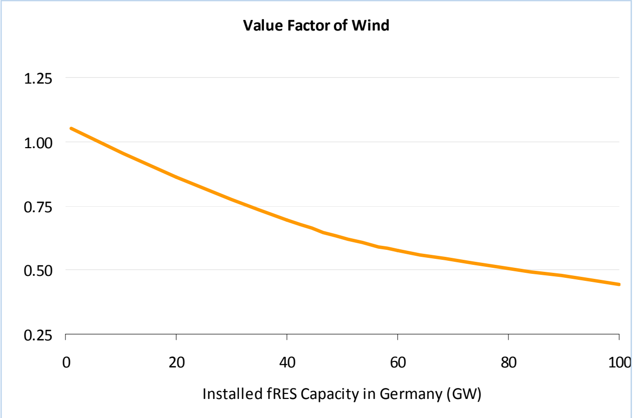

Figure 10: Value factor of wind under benchmark assumptions.

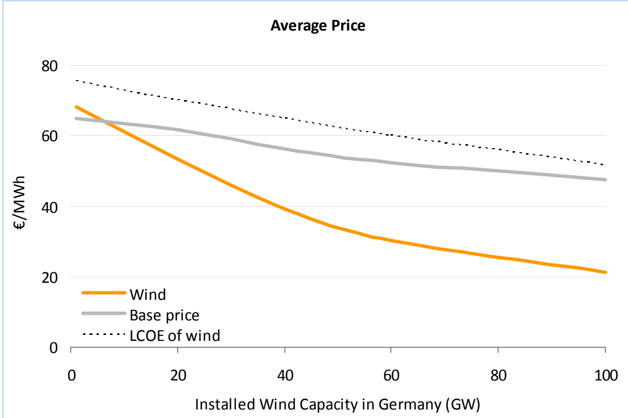

Figure 11: Average specific revenue of wind (orange), base price (grey), LCOE of onshore wind power (dotted) under benchmark assumption. Learning rate = 5%.

Figure 16 shows how capacity mix evolves for given amounts of wind power. Total dispatchable capacity is reduced from 94 GW to 79 GW, with hard coal and lignite being the fuels that are driven out of the system due to low prices and fewer running hours. Nuclear still earns its quasi-fixed costs and is not decommissioned. There is no investment in storage.

Figure 17 shows which fuel is the price setter during how much time of the year. One can see how the share of low-variable cost dispatchable technologies such as lignite and nuclear increases with higher wind deployment. At 100 GW the price drops to zero during 2200 hours of the year, when must-run generation becomes price-setting.

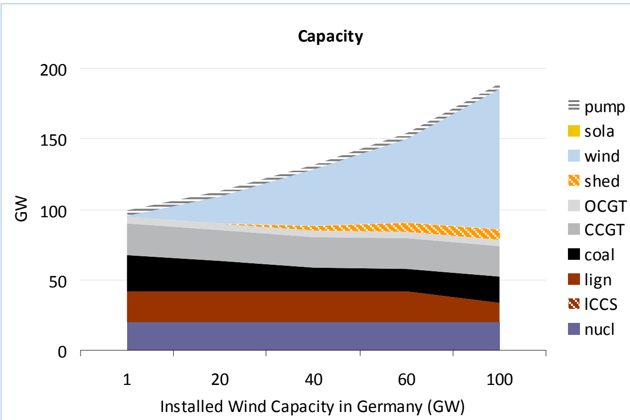

Figure 16: Endogenous capacity development for given wind capacity.

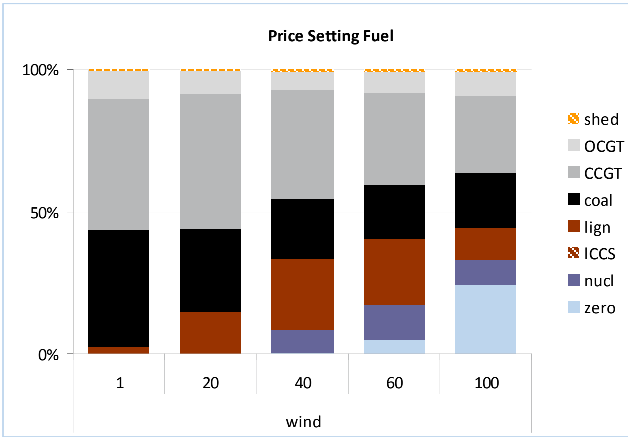

Figure 17: Price setting fuel at 1-100 GW of wind (share of time).

Wind curtailment remains limited in the model even at 100 GW wind capacity. At maximum, 21 TWh or 10% of all wind generation is curtailed. One reason for that is that the model gains some flexibility through transmission investments. Interconnector capacity roughly doubled at 100 GW compared to today's value. On the other hand and as mentioned above, investment in storage is absent. Only at 100 GW wind capacity, pump hydro storage marginally breaks even. At zero wind, operating profit is only half of what is needed to cover fix costs.

Solar value factors

Figures 12 and 13 present the results for solar power. For these runs, solar capacity was varied between zero and 100 GW in Germany and corresponding amounts in the other countries. At maximum, this is equivalent to generation from solar power of 19% of total consumption.

While observed market value factors have been significantly above unity, the model results indicate that the merit-order effect affects solar power as much as wind power. The value factor actually drops below 0.5 already at 50 GW installed solar capacity, specific revenues fall to 20 €/MWh at 100 GW. Thus is insofar surprising as solar generation is quite well correlated with demand, but consistent with Gowrisankaran et al. (2011). One explanation for the quickly falling solar value factor seems to be that solar generation is more "peaky" than wind, with a lot of generation concentrated in few hours, as show in figure 14. That means that as soon as 40 GW of solar power are installed, the residual load becomes very small or negative even during times of high (noon) demand.[21] Figure 13 shows that at a learning rate of 10% and a global growth rate four times as high as in Germany, even at 100 GW installed capacity LCOE are above revenues.

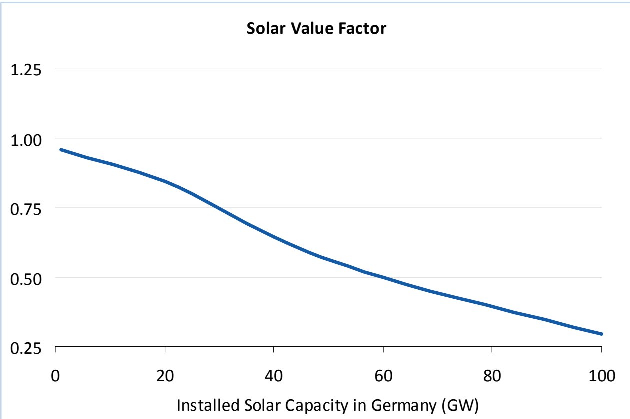

Figure 12: Value factor of wind in the benchmark run.

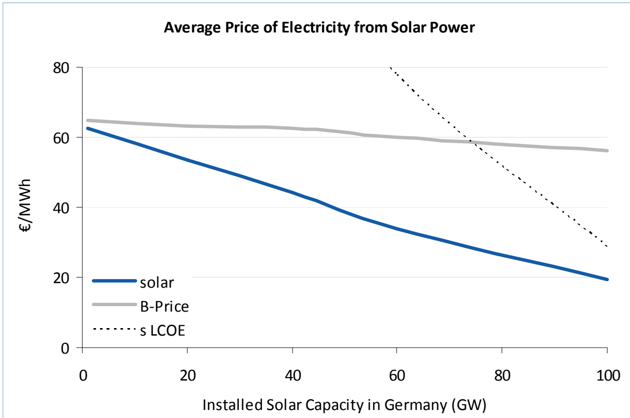

Figure 13: Average revenue of solar in the benchmark run (blue), base price (grey), LCOE of onshore wind power (dotted) at a learning rate of 10%.

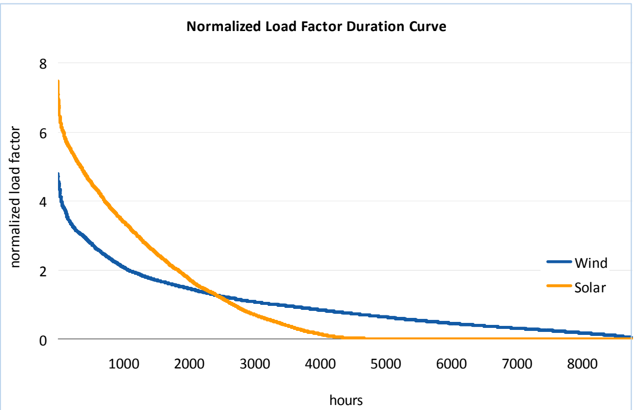

Figure 14: Normalized load factor duration curves for solar and wind power in Germany.

[21] Another factor could be that the generation profile of solar is better correlated across countries than the wind profile. This result is somewhat preliminary and needs further attention.

Interaction between wind and solar

So far, only wind *or* solar power was increased. No wind and solar power are increased simultaneously to understand interactions and complementarities.

Figure 15 and 16 show the value factors of wind and solar if both wind and solar are invested in and compares them to the case where only wind or solar was put into the model. Interesting, the wind value factor increases slightly when solar is added (at least at higher penetration rates) while the solar value factor decreases. The reason for the higher wind value factor could be that the solar generation decreases peak prices during noon and by that reduced the base price more than the wind profile (see historical market development, p. 7). The reason for the lower value factor of solar seems to be a quite different capacity development: With solar only being added to the system, hardly any conventional capacity is decommissioned. When wind power is added on top, hard coal and/or lignite plants are decommissioned. That makes the merit-order steeper, enforcing the merit-order effect during sunny hours.

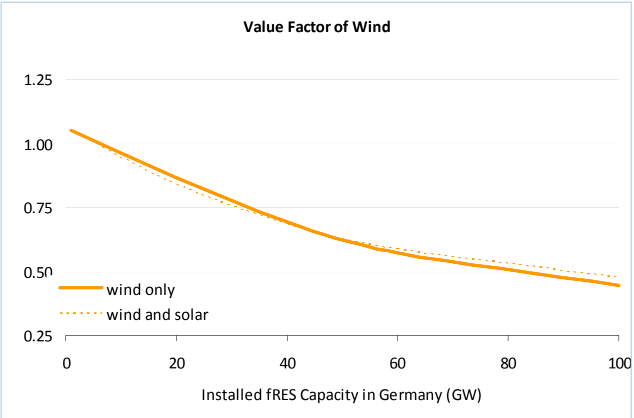

Figure 15: Wind value factors without (solid) and with (blue) solar power.

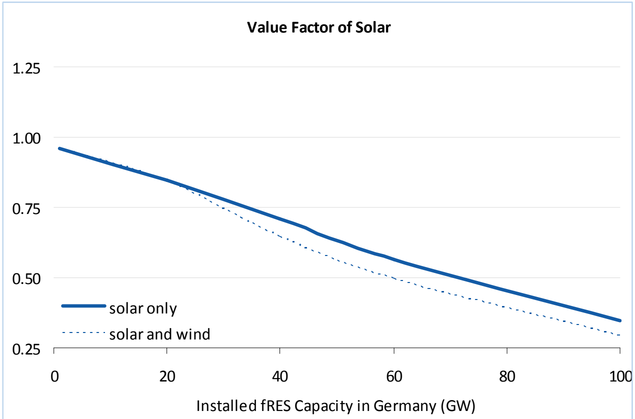

Figure 16: Solar value factors without (solid) and with (blue) wind power.

The effect of CO_2 pricing

In the following paragraphs, step by step the benchmark assumptions are changed and the impact on wind revenues assessed. Due to space constraints only results on wind power will be reported. (Results for solar are available upon request.)

One of the main drivers of change in the electricity system is CO_2 pricing. Higher CO_2 prices imply higher variable costs for fossil plants and thus higher electricity prices. On the other hand, they trigger investments in low-carbon technologies such as nuclear power, which have low variable cost and thus result in low prices especially during wind times. Thus a priori it is not obvious if a higher CO_2 price is beneficial for wind generators. To evaluate the impact of CO_2 pricing, the benchmark price of 20 €/t was changed to 1 €/t and 75 €/t.

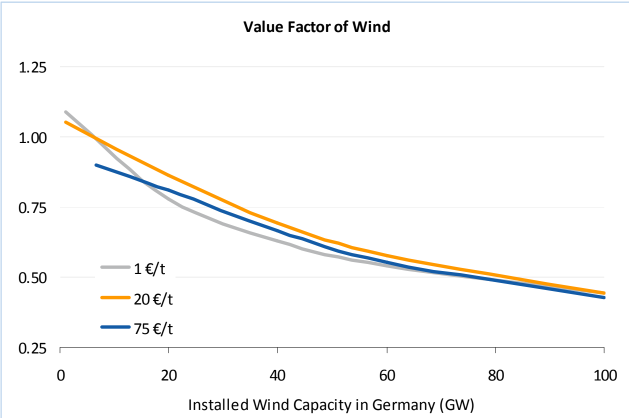

Figure 20: Wind value factors at various CO2 prices. The orange line (20 €/t) shows the benchmark run.

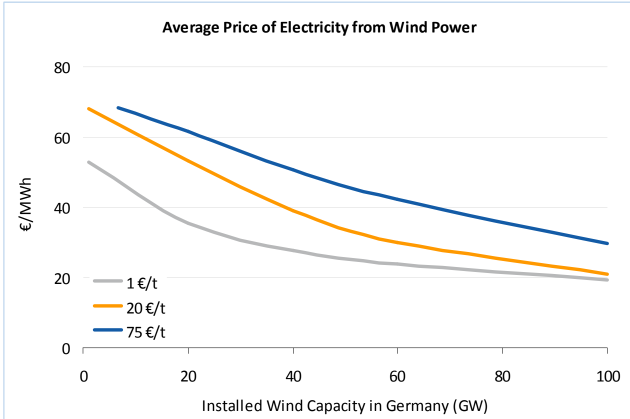

Figure 21: Wind revenues at various CO2 prices. The orange line (20 €/t) shows the benchmark run.

Figure 20 and 21 show results. Wind power benefits from higher CO_2 prices in form of higher revenues, because the overall electricity price level increases, on average by 20 €/MWh. Interestingly, *both* higher and lower CO_2 prices reduce the value factor. At low prices, new lignite investments are triggered, and a low price makes the merit-order curve in the lignite-hard coal-CCGT range steeper, pronouncing the merit-order effect of wind and thus reducing the value factor. At high CO_2 prices new nuclear investment is triggered that has a similar effect on the value factor of wind.

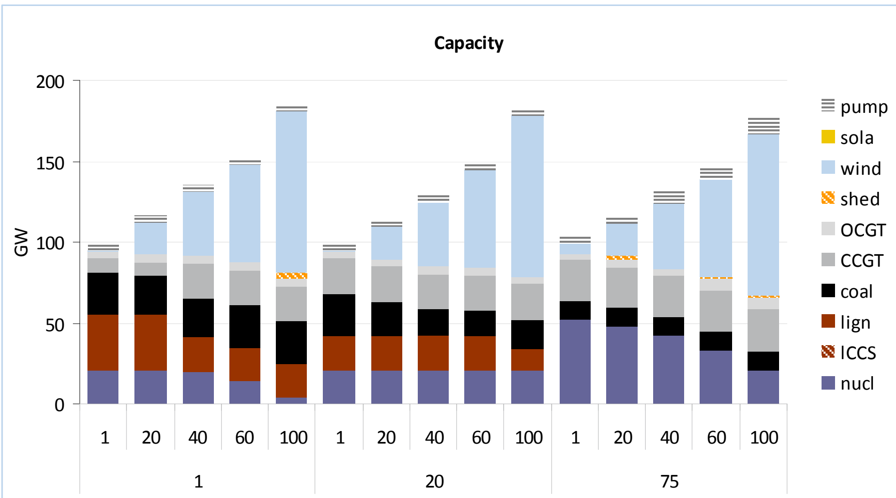

Figure 22: Capacity development at 1 €/t CO_2, 20 €/t, and 75 €/t and 1 GW – 100 GW wind power.

As figure 22 suggests, the high-CO_2-price result depends heavily on the possibility to invest in large scales into nuclear power. Given recent political developments one can have doubts regarding these model runs being realistic. The sensitivity to a nuclear phase-out was tested in two additional runs:

First, nuclear power was phased out all over Europe at the benchmark CO_2 price of 20 €/t, second in addition the CO_2 price was increased to 75 €/t. CCS was not allowed in that run.

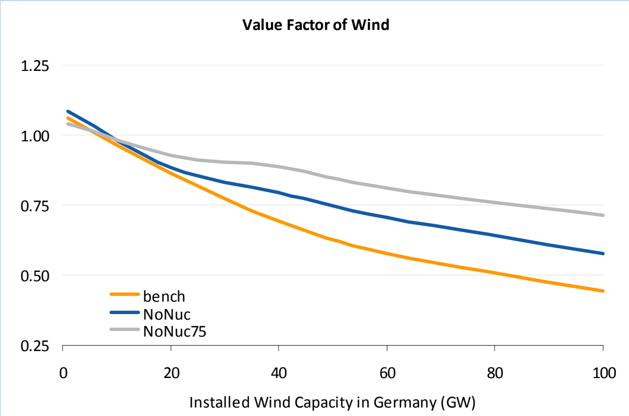

Figure 23: Wind value factors without nuclear and at 20 €/t and 75 €/t CO_2.

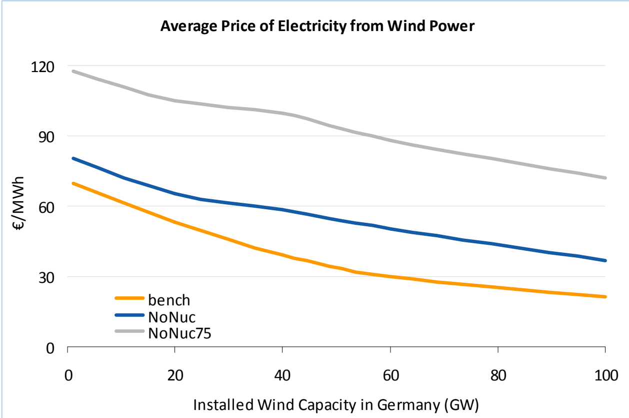

Figure 24: Wind revenues without nuclear and at 20 €/t and 75 €/t CO_2.

Figure 25: The merit-order curve of NoNuc75.

The combined effect of a high CO_2 and the phase-out of nuclear is drastic. The base price almost doubles, all lignite is crowded out and in Germany between 20 GW and 40 GW of new CCGT capacity is built. For wind power, this scenario is quite perfect: The merit-order becomes so flat that the price virtually never drops below 88 €/MWh, the variable costs of hard coal (figure 25). That is reflected in the value factor, which remains above 0.7 even at 100 GW wind power in Germany (figure 23). As a matter of fact, at a learning rate of 5%, wind power levelized costs would drop to around 50 €/MWh well below revenues of 70 €/MWh (figure 24), meaning that more than 100 GW of wind power would be competitive in Germany.

The effect of fuel prices

For the benchmark runs, constant fuel prices of 12 €/MWh$_t$ for hard coal and 25 €/MWh$_t$ for CCGTs were assumed. While fuel analysts often argue that for the foreseeable future sufficient coal and gas resources are available at long-run marginal costs around these numbers, many studies on the electricity system assume higher and/or increasing fuel prices. There here sensitivity runs with higher fuel prices are presented. A plausible expectation is that higher fuel costs, driving up the electricity price, increase the revenues of wind power. To test how sensitive the market value of wind power is with respect to fuel prices, coal and gas prices were doubled individually and simultaneously.

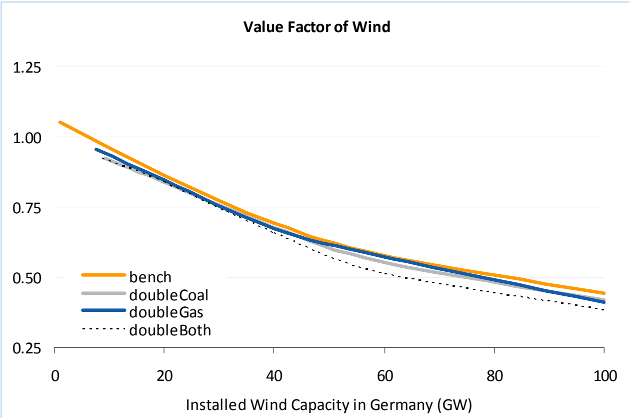

Figure 26: Wind value factors at benchmark fuel prices (orange), with more expensive coal (grey), more expensive gas (blue) and more expensive gas and coal (dotted).

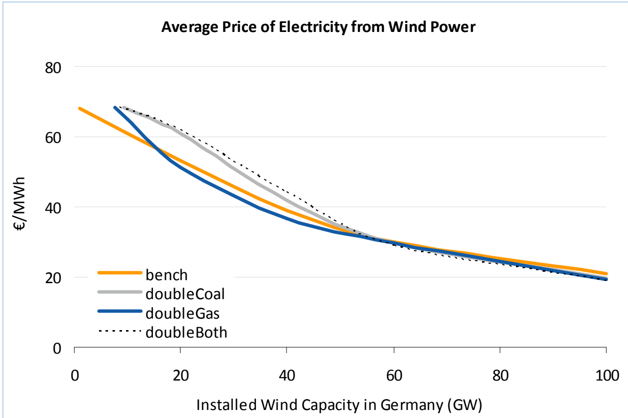

Figure 27: Wind revenues at various fuel prices.

The results as presented in figure 26 and 27 are to some extend counter-intuitive and show an interesting non-monotonic behaviour. Let's first look at the results at intermediate wind penetration rates between 20 and 50 GW. A higher coal price increases the specific revenues while leaving the value factor unchanged. Higher coal prices drive up electricity prices for two reasons: They cause higher prices when coal is price setter, and they induce fuel switch to gas. Furthermore, the merit-order becomes very flat with hard coal and gas having almost the same variable costs. In contrast, higher gas prices *reduce* the electricity price level. This is because the price increase induces a switch from gas to coal and lignite, which have lower variable costs. Increasing both hard coal and gas prices does not increase the base price much more than coal alone, because of resulting very large lignite investments. In all these settings, the value factor remains virtually unchanged.

Above 50 GW the situation is different: In all high-price scenarios (gas, coal, both), the base price increases slightly, because lignite investments limit the effect of higher coal and gas prices. However, the combination of much lignite and much wind power reduce the wind value factor significantly below the benchmark value factors. In most runs, during more than half of all hours nuclear or lignite set the price. Thus, higher fuel prices *reduce* the average revenue of wind power!

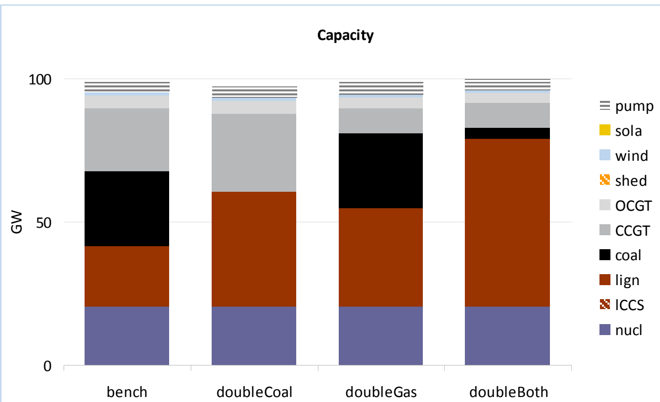

Figure 28: Capacity mix without wind in the benchmark and with higher fossil fuel prices.

The effect of interconnector capacity

Cross-border flows between market areas are limited by NTCs in the model. To test how sensitive the market value of wind reacts on increased or decreased international integration, NTC values were exogenously set to zero and doubled. Given the attention that transmission expansion receive in the public and academic debate on fRES (e.g. TradeWind, EWIS, dena II), one could expect the impact of more transmission capacity on wind income to be positive and significant.

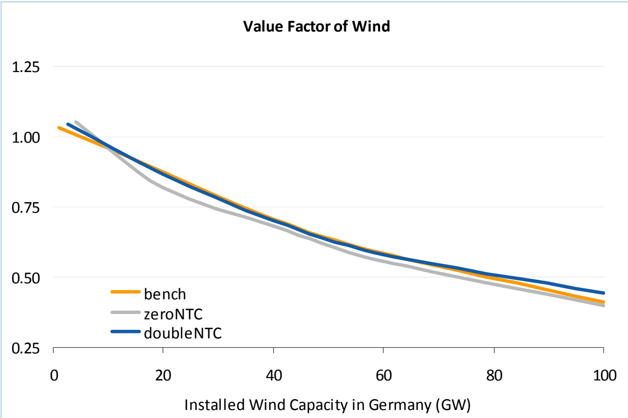

Figure 30: Wind revenues at different NTC levels.

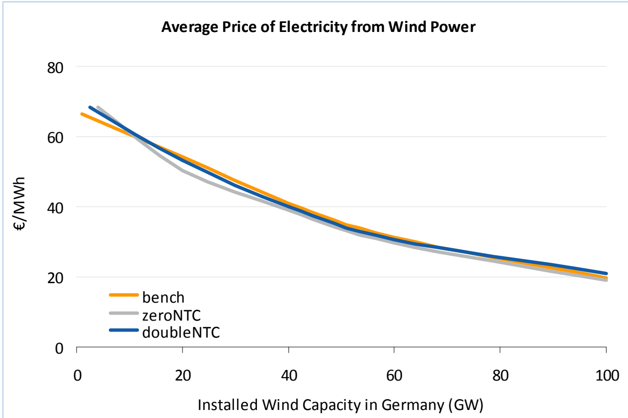

Figure 31: Wind revenues in France in at different NTC levels.

Here comes the surprise: The impact of more cross-border transmission capacity on wind revenues in Germany is very small, and slightly negative at intermediate levels of wind penetration (see figure 30).[22]

The main reason for the negative impact of more NTC capacity on revenues of wind power in Germany seems to be imports from France. In France, prices are often set by nuclear power during windy hours. Since wind generation profiles correlate well between Germany and France (p=0.4), during windy hours more often cheap electricity from France is imported to Germany when interconnector capacity is increased. In France we see the opposite effect (figure 31): Increasing the cross-border transmission capacities reduces the number of hours when French wind is locked in with low prices set by nuclear. This interpretation is supported by the outcome of the capacity development: While in the benchmark at 40 GW wind, 4 GW nuclear capacity is decommission in France, that number increases to 8 GW if exports are forbidden and is reduced to zero if NTCs are doubled.

[22] Recall that at the moment only six countries are included, and hydro reservoirs are not modelled. That limits the robustness of the reported result considerably.

The effect of storage

Electricity storage is often mentioned as a way to level out fluctuation electricity generation from fRES. While this is of course in principle correct, it is not well understood how much and what kind of storage is needed. To test an existing technology, pump hydro storage capacities in the model region was taken away in one run and doubled in a second run.

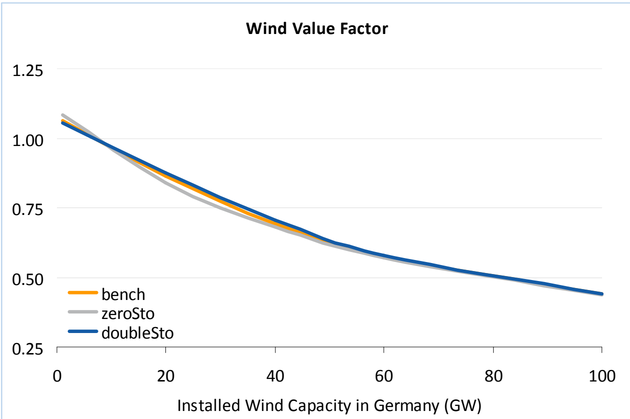

Figure 32: Wind revenues at different NTC levels.

Figure 32 shows that the role of pump hydro storage is very limited, because of its small size compared to installed fRES capacity.

The effect of geography

If wind power is installed not evenly distributed to all countries, but used more heavily in one than the others, two effects reduce efficiency and reduce the income of wind generators: First, there is limited transmission capacity between countries, resulting in inefficient dispatch and wind curtailment. Wind power is locked-in and prices drop more during windy hours. Second, the wind generation profiles of different countries are less than perfectly correlated. That means that the aggregated profile of a broader distributed wind turbine fleet is smoother than a more concentrated one. Thus even with unlimited transmission capacity economic efficiency would be improved by spreading out wind turbines. To test the effect on revenues, all European wind capacity was concentrated in Germany which results in 2.8 times higher capacity in Germany (and zero capacities in all other countries). To detangle the two effects, cross-border transmission capacities are set to infinity in a second run. The only remaining effect is the one of different generation profiles.

Not surprisingly, if all European wind power was concentrated in one country, the value factor would decrease even more than if it was installed wide spread: It falls to 0.33 at maximum capacity, implying an average revenue of only 13 €/MWh. The price in Germany would drop to zero in 4000 hours of the year and 200 TWh had to be curtailed (a third of wind generation). If there are no transmission limits, the average revenue for wind power is 17 €/MWh, still significantly below the 21 €/MWh that generators earn if turbines are installed in all countries.

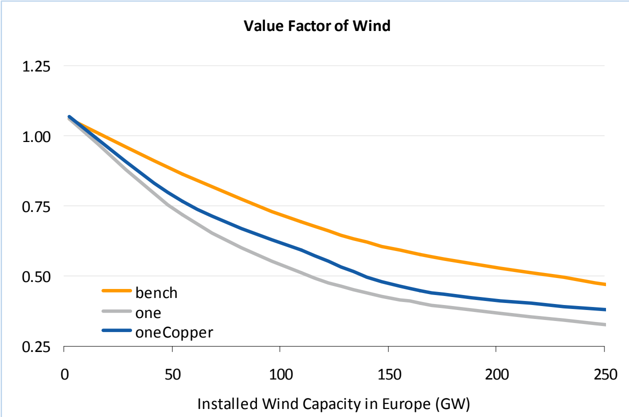

Figure 33: Wind value factors in Germany for European (bench) vs. German wind allocation (one) and with unlimited transmission capacities (oneCopper).

Figure 33 shows how important spatially wide-spread installation is to average out fluctuations. The aggregate generation profile is much smoother than any individual profile by itself.

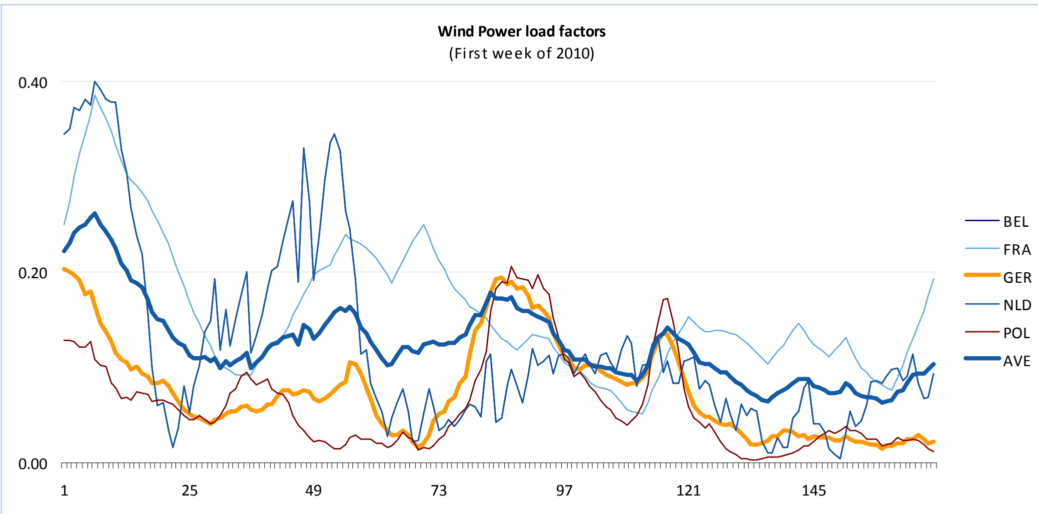

Figure 33: Hourly load factors by country and as a weighted average (AVE, compare to figure 6). The same weights were used as for the distribution of capacity across countries (relative yearly consumption).

The effect of flexible conventional generators

It is often concluded in academic and popular literature that the electricity system needs to become more flexible to integrate wind power. In the context of the present work, the impact of additional flexibility of the generation portfolio can be tested by relaxing two constraints: The spinning reserve requirement and CHP must-run.

The minimum requirement on spinning reserves is meant to represent the provision of necessary ancillary services such as regulating power as well as voltage support. In each country conventional generators with a capacity of 20% of annual peak load have to be online (18 GW in Germany). In the long term, one can think of alternative providers of these ancillary services, e.g. phase-shift transformers, electronics, batteries or demand response. One way to make the electricity system more flexible is to introduce such suppliers in order to relax the spinning reserve requirement. To test the potential impact of such a measure on wind revenues, the spinning-reserve requirement is set to zero.

CHP generators have requirement to generate heat when heat is consumed. This makes them must-run units that are willing to provide electricity at any price. They can be made mode flexible by installing heat storage equipment. To test the impact of such a measure, it has been assumed that all CHP plants can be dispatched freely, just like any condensing plant. This is obviously a very extreme assumption, but gives an upper limit of the effect of CHP flexibility.

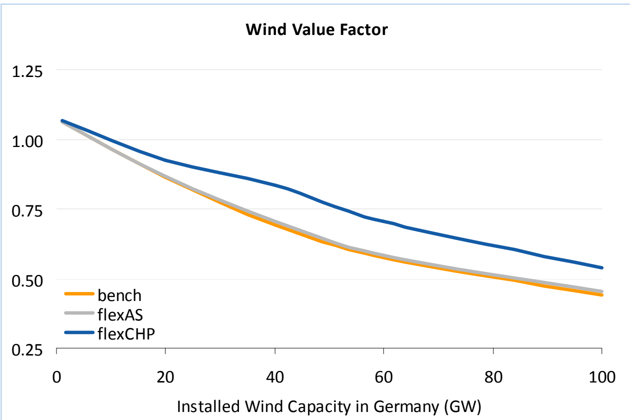

Figure 35: Wind revenues without the spinning reserve constraint (grey) and without CHP must-run (blue) compared to the benchmark results (orange).

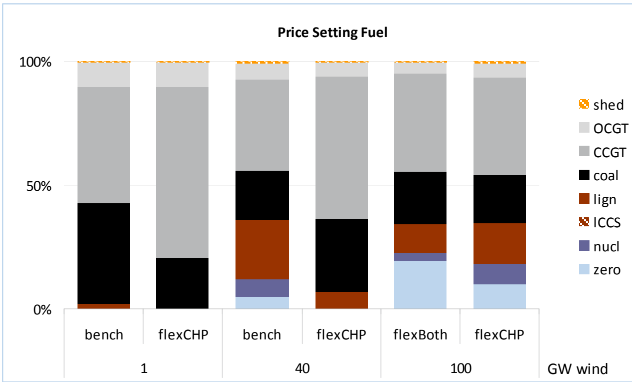

Figure 36: Price setting fuel at 1 GW, 40 GW and 100 GW wind capacity, with and without heat storage.

Figure 35 shows the value factors of these runs. While the spinning-reserve constraint apparently is not binding at all, relaxing the CHP must-run constraint has an huge impact on wind earnings: The value factor jumps by 10-15 percentage points, throughout the range of 30 to 100 GW installed capacity. This implies that making CHP plants more flexible could have a significant impact on wind revenues even today, and continues to have much impact as more fRES capacity is installed.

Figure 36 gives a different perspective on the significant effect of making CHP flexible: The share of time when the price drops to zero is reduced, but also the number of hours when other low-variable cost technologies are price setting can be reduced. In the merit-order curve, CHP capacity is taken out and everything else moves to the left.

The effect of capacity markets

Most electricity markets are energy-only markets where there is a price for electricity, but not for generation capacity. Several European countries, including Poland, the UK and France, will certainly or probably introduce capacity markets in the coming years. There are many ways to design a market for capacity, and the proposals in the countries mentioned differ significantly. For modelling reasons, it is assumed that the capacity market finances investments in peak-load capacity or load shedding. Two model runs are presented, one with peak-load capacity that provides electricity to the (energy) market at 250 €/MWh without requiring any fix costs, and one run where the cut-off price is 150 €/MWh. Recall that also in the benchmark run a fix costs-free "load shedding" technology was assumed, at variable costs of 1000 €/MWh. One might expect that such a policy, by cutting of the electricity price at the capacity market-threshold, drives down the base price and reduces the revenues of all generators, including wind power (see Borenstein 2008).

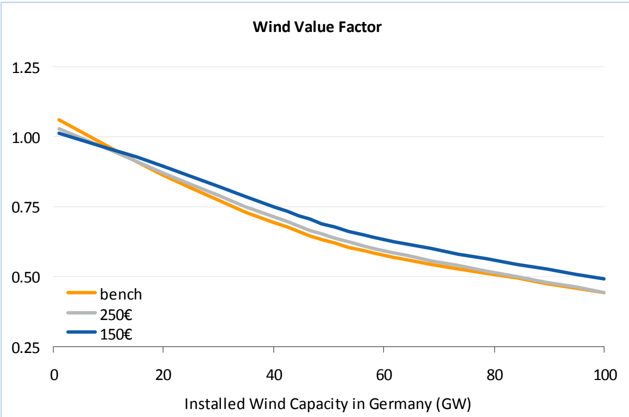

Figure 37: Wind value factors with capacity markets.

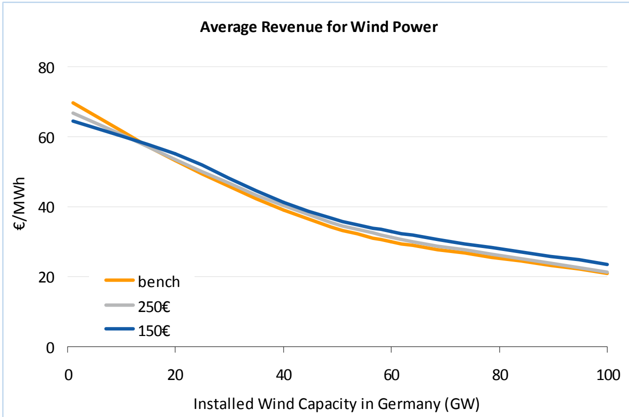

Figure 38: Specific wind revenues with capacity markets.

Figures 37 and 38 show that the opposite is the case: Markets for peak-load capacity *increase* the revenue of wind power, even though the effect is limited in size. The reason can be found in capacity development, as shown in figure 39: Capacity markets push more peak-load capacity into the system, replacing conventional capacity partly. The technology mix is distorted by increasing peak-load capacity. The new leak-load capacity will set the price in a significant number of hours (figure 40), helping to increase revenues of wind power.

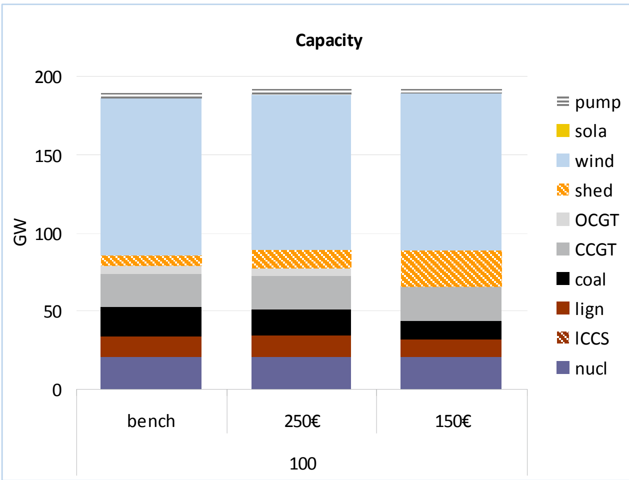

Figure 39: Capacity mix with and without capacity markets. (100 GW Wind power)

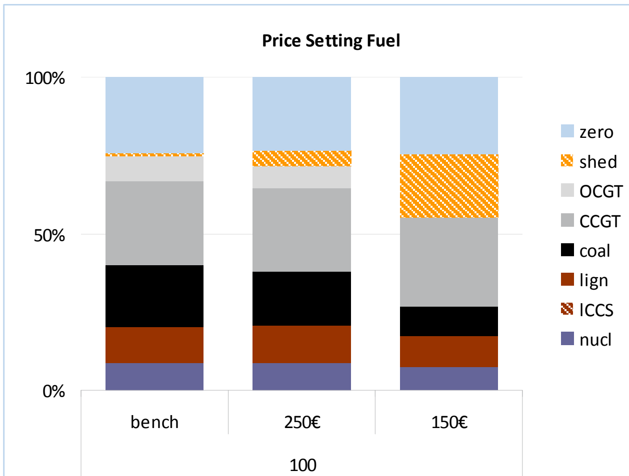

Figure 40: Price-setting technology with and without capacity markets. (100 GW Wind powering all runs). Note that in the benchmark run the price of "shed" is 1000 €/MWh, in the "250€" run it is 250 €/MWh and the last run it is 150 €/MWh.

The long-run equilibrium

In all model runs so far, existing generation capacity was taken as given, but decommissioning as well as additional investments were possible. In economic terms, this can be labelled a "mid-term" perspective. In a "short-term" analysis, investments and decommissioning are not possible. In a "long-term" view, existing plants have passed their technical life-time and are decommission, and all capacity is due to an investment decision. The outcome of such a long-term analysis is the long-run market equilibrium at given technology and input price parameters. With free market entry and no existing capacities, the long-run equilibrium implies that all generators earn their market-rate of return and there are no profits. The following figures present the results from a mid-term (benchmark), a short-term, and a long-term model run.

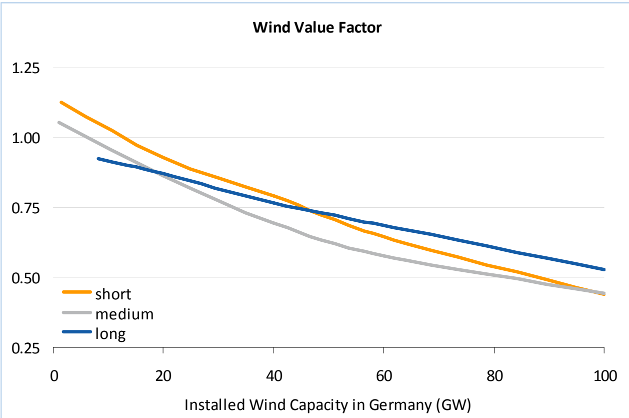

Figure 41: Value factors with the existing plant stack and without investment (short), with investment (short), and without an existing plant stack (long).

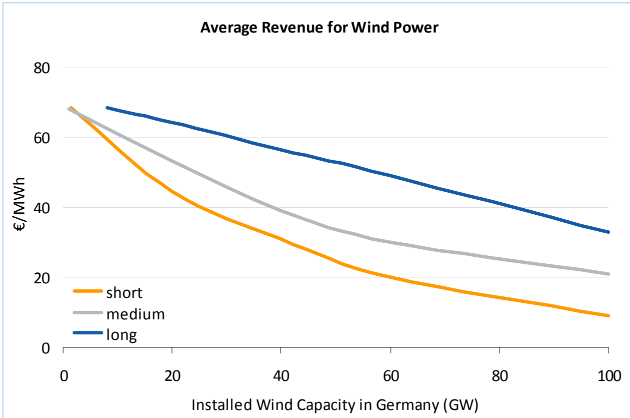

Figure 42: Average revenue.

In the long-run, without sunk investments, the electricity system is more flexible. Since wind power is given exogenously, the blue line represents the electricity system that is most cost-efficient given a certain amount of wind power: It represents the system that "fits" best to a given amount of wind power. This results in the highest revenues for wind power, since the system is no locked in with too high amounts of base-load technologies. Even in the long-run equilibrium value factors decrease to 0.5 at 100 GW installed capacity and revenues fall below 40 €/MWh. While this is still low in absolute numbers, it is 60% more than in the medium (benchmark) run.

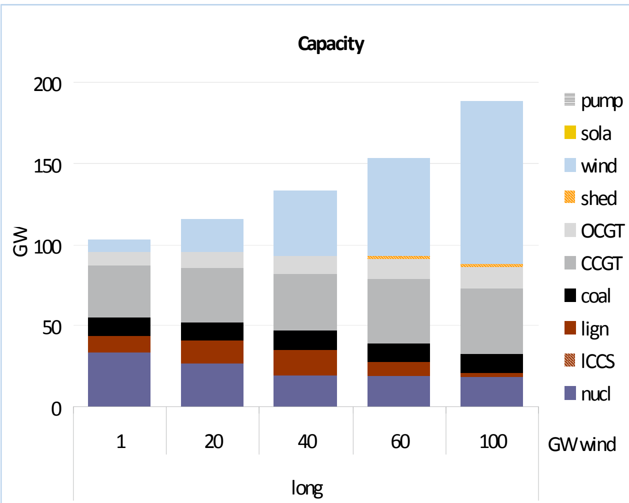

Figure 43: The optimal (long-run) capacity mix at 1 GW to 100 GW wind power. Note the decreasing share of low-variable cost technologies, especially lignite and nuclear.

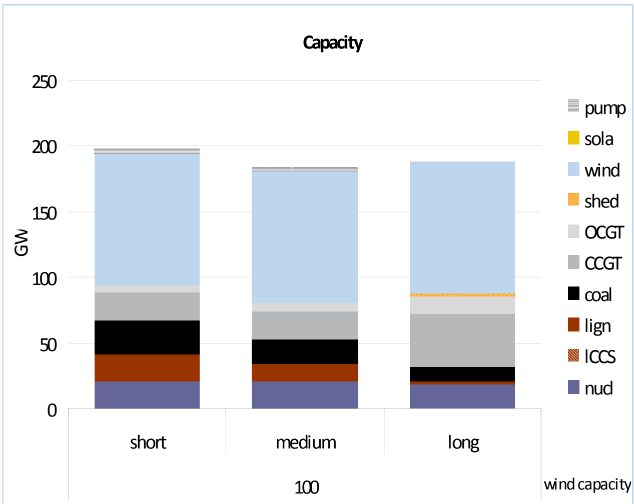

Figure 44: The existing plant stack (short), existing plant stack + (dis-) investment (medium) and the optimal capacity mix (long) at 100 GW of wind power in Germany. The optimal mix has much larger shares of gas plants and a lower share of base-load plants.

5. Conclusions

Electricity markets where an energy-only price is determined by the variable cost of the marginal generator and with limited intertemporal flexibility (that is, thermal systems under today's market design) provide a frosty environment for low-marginal-cost fluctuating renewables like wind and solar power. Once large capacities are installed, the merit-order effect depresses the electricity price whenever the primary energy source is available in large amounts.

While today in Germany, wind power has a market value of more than 0.9 of the base price, and solar of 1.1, both value factors are estimated to drop to 0.8 when 50 GW of the respective technology is installed and below 0.5 at 100 GW installed capacity. That means that the decrease in investment and O&M cost in order for these technologies to become competitive has to be even steeper than most observers believe.

Several factors have been identified to have a significant impact on the market value of solar and wind power. The three most important drivers might be a) the role of nuclear power, b) the flexibility of must-run generators, and c) the combination of CO_2 and fuel prices. Additional interconnector capacity and additional storage capacity have very limited effects. While one might have believe that interconnectors have an positive and capacity markets a negative effect, model results point in the different direction. Many factors have significant influence on capacity and generation mix, and those shifts counterbalance some and enforce other direct effects on the market value of fRES.

Table 7: What affects wind revenues?

Parameter change	**Effect on wind revenues**	**Chain of Causality**
Higher CO_2 price	↑ (+10 €/MWh at increase of 55 €/t CO_2)	Higher electricity prices if fossil fuels are price setting (+); flatter merit-order in the lignite-hard coal-gas range (+); counterbalanced by investments in nuclear (-)
Higher gas price	↓ (-2 €/MWh at double gas price)	Increases the electricity price if gas is price setter (+); investments in coal and lignite reduce price in windy hours (-)
Higher coal price	↑ (up to +8 €/MWh at double coal price)	Increases the electricity price if coal is price setter (+); investments in gas increase the effect (+); investments in lignite counterbalance (-)
More interconnector capacity	↓ / → (-1 €/MWh at double IC capacity)	Combination of high NTC capacity and much wind power and good correlation between French and German winds makes French nuclear price setting in Germany in wind hours (-)
More storage capacity	↑ / → (+1 €/MWh at double IC capacity)	Levels out electricity prices (+)
Spatial distribution of wind capacity	↓ (up to -13 €/MWh if all wind power was in Ger)	Lock-in of cheap prices during windy hours by limited transmission capacity (-); more spiky generation profile (-)
More flexible CHP plants	↑ (up to +14 €/MWh with entirely flexible CHP)	Reduced must-run generation leads to higher prices especially during hours of high fRES supply (+)
Capacity markets	↑ (+3 €/MWh at 150 €/MWh cut-off price)	By increasing the share of peak-load capacity, capacity markets reduce conventional capacity, leading to higher prices during windy hours (+)

In the long run, all capacity is endogenous and the electricity system has additional degrees of freedom to integrate fRES. This results in a generation capacity mix with higher shares of mid-load and peak-load capacity that today. However, the average wind revenue drops from 70 €/MWh below 40 €/MWh even without any existing capacity.

Several policy conclusions could be drawn from this work. First, increasing the flexibility of the system through demand response, electricity storage and relaxed constraints on conventional generators should be a top priority for research, engineering, and policy. Results presented here indicate that making CHP generators more flexible could be a relative quick wind. Second, at today's electricity system parameters, wind and solar power will have a very hard time to become competitive on the market, even at very steep learning rates. Cost reductions of investment and O&M costs have to be two to three times higher as indicated by studies which do not take the merit-order effect into account. Finally, the results indicate how important it is to find dispatchable renewable energy sources or fRES that are negatively correlated with wind and solar availability to reach ambitious climate and renewable targets.

The work presented here could be extended in several directions. One topic of future research is the second important factor that determines the market value of renewables: Uncertainty of production, forecast errors, and resulting imbalance costs. Another topic could be to use a similar model setup to understand and evaluate the role of specific flexibility options, including specific storage technologies, demand side management, long-distance interconnections, and heat storage on the supply as well as the demand side.

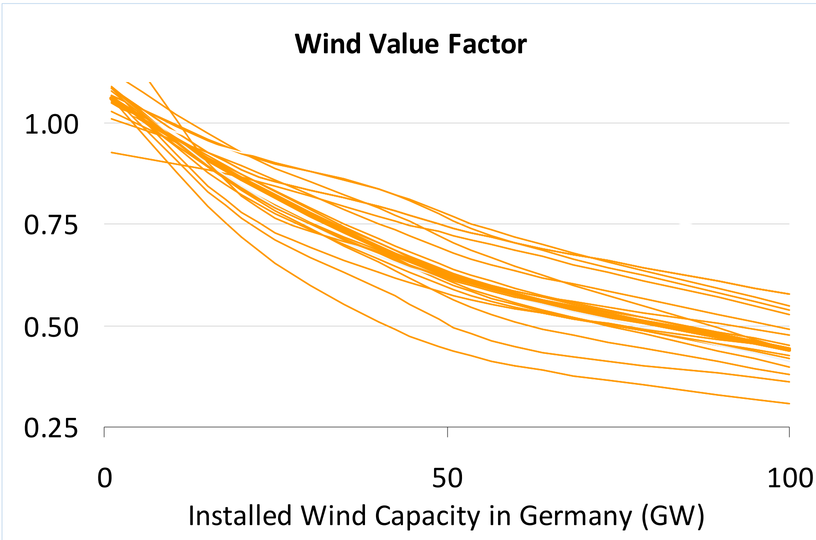

Figure 45: Value factors in all model runs. Despite the large span indicates considerable uncertainty, a significant fall of the value factor below 0.8 at 50 GW and below 0.6 at 100 GW is reported under all conditions.

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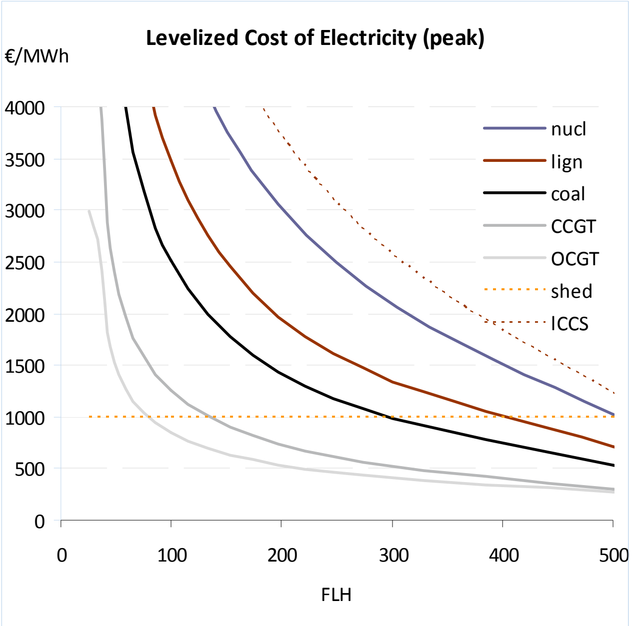
7. Appendix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2500
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coal
CCGT
OCGT
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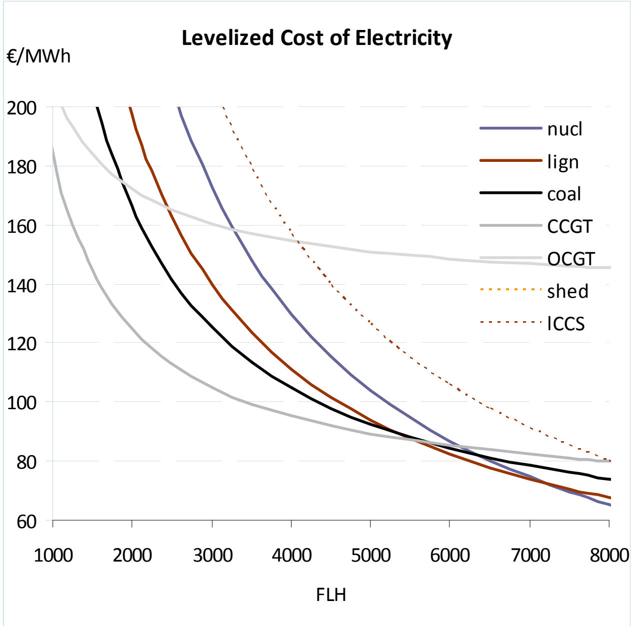
Levelized Cost of Electricity
€/MWh
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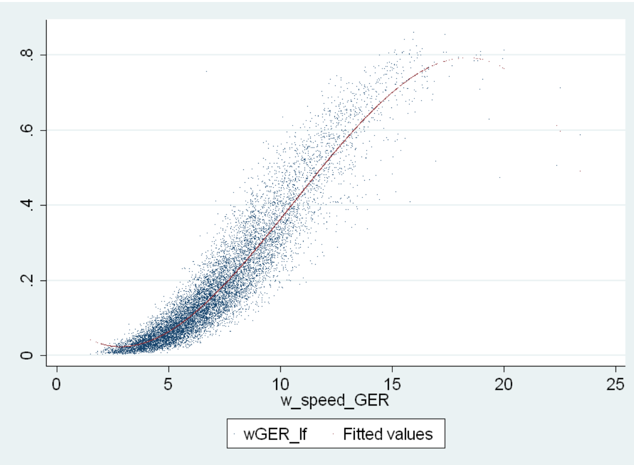
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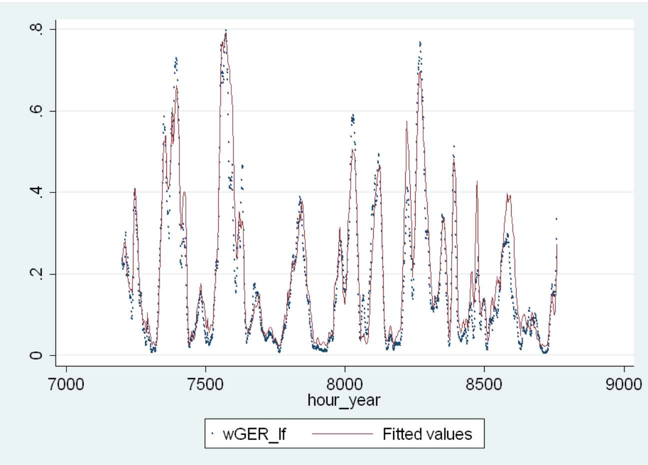
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