The Market Value of Variable Renewables

The Effect of Solar and Wind Power Variability on their Relative Price

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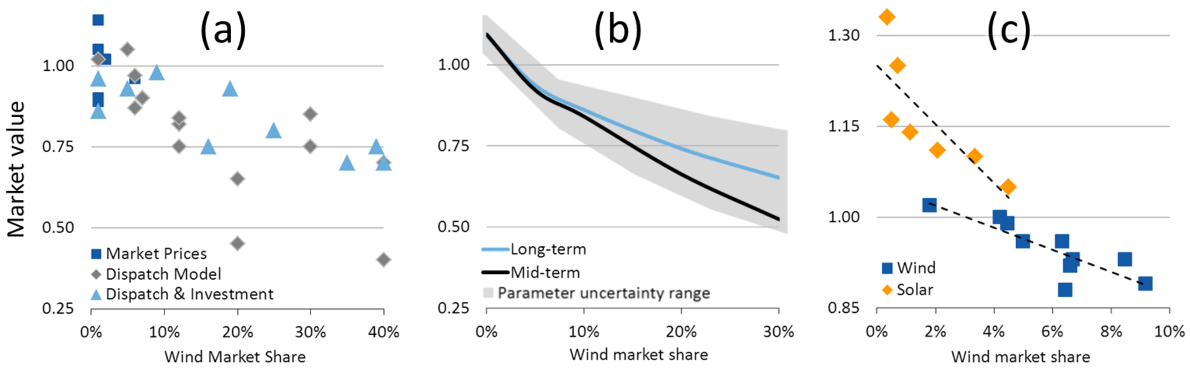
Abstract – This paper provides a comprehensive discussion of the market value of variable renewable energy (VRE). The inherent variability of wind speeds and solar radiation affects the price that VRE generators receive on the market (market value). During wind and sunny times the additional electricity supply reduces the prices. Because the drop is larger with more installed capacity, the market value of VRE falls with higher penetration rate. This study aims to develop a better understanding how the market value with penetration, and how policies and prices affect the market value. Quantitative evidence is derived from a review of published studies, regression analysis of market data, and the calibrated model of the European electricity market EMMA. We find the value of wind power to fall from 110 percent of the average power price to 50-80 percent as wind penetration increases from zero to 30 percent of total electricity consumption. For solar power, similarly low values levels are reached already at 15 percent penetration. Hence, competitive large-scale renewables deployment will be more difficult to accomplish than many anticipate.

- The variability of solar and wind power affects their market value.
- The market value of variable renewables falls with higher penetration rates.
- We quantify the reduction with market data, numerical modeling, and a lit review.
- At 30% penetration, wind power is worth only 50-80% of a constant power source.



Wind value factor estimates from a literature review (a), the numerical model EMMA (b), and German historical market data (c). The value factor (wind revenue over base price) decreases with higher penetration rates.

Keywords – variable renewables; wind power; solar power; power system modeling; market integration of renewables; electricity markets; intermittency; competitiveness of renewables; cost-benefit analysis. *JEL* – C61, C63, Q42, D40

The findings, interpretations, and conclusions expressed herein are those of the author and do not necessarily reflect the views of Vattenfall or the Potsdam-Institute. Lion Hirth, Vattenfall GmbH, Chausseestraße 23, 10115 Berlin, lion.hirth@vattenfall.com, +49 30 81824032.

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1. Introduction

Electricity generation from renewables has been growing rapidly during the last years, driven by technological progress, economies of scale, and deployment subsidies. Renewables are one of the major options to mitigate greenhouse gas emissions and are expected to grow significantly in importance throughout the coming decades (IPCC 2011, IEA 2012). According to official targets, the share of renewables in EU electricity consumption shall reach 35% by 2020 and 60-80% in 2050, up from 17% in 2008.[2] As hydro power potentials are largely exploited in many regions, and biomass growth is limited by supply constraints and sustainability concerns, much of the growth will need to come from wind and solar power. Wind and solar are variable[3] renewable energy sources (VRE) in the sense that their output is determined by weather, in contrast to "dispatchable" generators that adjust output as a reaction to economic incentives. Following Joskow (2011), we define the market value of VRE as the revenue that generators can earn on markets, without income from subsidies. The market value of VRE is affected by three intrinsic technological properties:

- The supply of VRE is *variable*. Due to storage constraints and supply and demand variability, electricity is a time-heterogeneous good. Thus the value of electricity depends on *when* it is produced. In the case of VRE, the time of generation is determined by weather conditions. Variability affects the market value because it determines when electricity is generated.
- The output of VRE is *uncertain* until realization. Electricity trading takes place, production decisions are made, and power plants are committed the day before delivery. *Forecast errors* of VRE generation need to be balanced at short notice, which is costly. These costs reduce the market value.
- The primary resource is bound to certain *locations*. Transmission constraints cause electricity to be a heterogeneous good across space. Hence, the value of electricity depends on *where* it is generated. Since good wind sites are often located far from load centers, this reduces the value of wind power.[4]

We use a framework introduced in Hirth (2012a) and compare the market income of a VRE generator to the system base price. The system base price is the time-weighted average wholesale electricity price in a market. The effect of variability is called "profile costs", the effect of uncertainty "balancing costs" and the effect of locations "grid-related costs". The label these components "cost" for simplicity, even though they might well realize as a discount on the price and not as costs in a bookkeeping sense.

Profile, balancing, and grid-related costs are not market failures, but represent the intrinsic lower value of electricity during times of high supply, at remote sites, and the economic costs of uncertainty.

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[2] National targets for 2020 are formulated in the National Renewable Energy Action Plans. Beurskens et al. (2011), Eurelectric (2011a), PointCarbon (2011) and ENDS (2010) provide comprehensive summaries. EU targets for 2050 have been formulated in EC (2011). Historical data are provided by Eurostat (2011).

[3] Variable renewables have been also termed intermittent, fluctuating, or non-dispatchable.

[4] Of course all types of generation are to some extend subject to expected and unexpected outages and are bound to certain sites, but VRE generation is much more uncertain, location-specific, and variable than thermal generation. Also, while weather conditions limit the generation of wind and solar power, they can be always downward adjusted and are in this sense partially dispatchable. The fourth typical property of VRE that is sometimes mentioned (Milligan et al. 2009), low variable costs, does not impact the value of electricity.

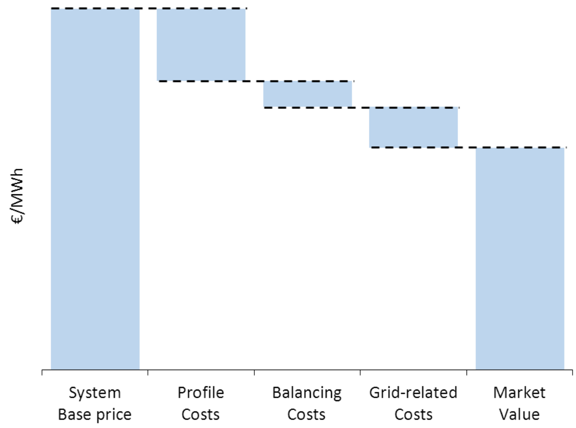

Figure 1. The system base price and the market value of wind power. The difference between those two can be decomposed into profile, balancing, and grid-related costs.

In this paper, we focus on the impact of variability on the market value of VRE, leaving uncertainty and location for further research. The reason for doing so is that in a broad literature review we have identified profile costs as the largest cost component and found this topic under-researched relative to balancing costs (Hirth 2012a).

The market value of VRE will be measured as its relative price compared to the base price. We call this relative price "value factor"[5] and define it more rigorously in section 3. The value factor is calculated as the ratio of the hourly wind-weighted average wholesale electricity price and its time-weighted average (base price). Hence the value factor is a metric for the valence of electricity with a certain time profile relative to a flat profile (Stephenson 1973). The wind value factor compares the value of actual wind power with varying winds with its value if winds were invariant (Fripp & Wiser 2008). In economic terms, it is a relative price where the numeraire good is the base price. A decreasing value factor of wind implies that wind power becomes less valuable as a generation technology compared to a constant source of electricity.

There are two mechanisms through which variability affects the market value of renewables in thermal[6] power systems. We label them "correlation effect" and "merit-order effect". If a VRE generation profile is positively correlated with demand or other exogenous parameters that increase the price, it receives a higher price than a constant source of electricity (correlation effect) – as long as its capacity remains small. For example, while the 2011 base price in Germany was 51 €/MWh, solar power received an average price of 56 €/MWh (a value factor of 1.1) on the market, because it is typically generated when demand is high. In Europe, there is a positive correlation effect for solar due to diurnal correlation with demand, and for wind because of seasonal correlation.

[5] In the German literature known as "Profilfaktor" or "Wertigkeitsfaktor."

[6] "Thermal" (capacity-constrained) power systems are systems with predominantly thermal generators. These systems offer limited possibility to store energy. In contrast, (energy-constrained) "hydro" systems have significant amounts of hydro reservoirs that allow storing energy in the form of water.

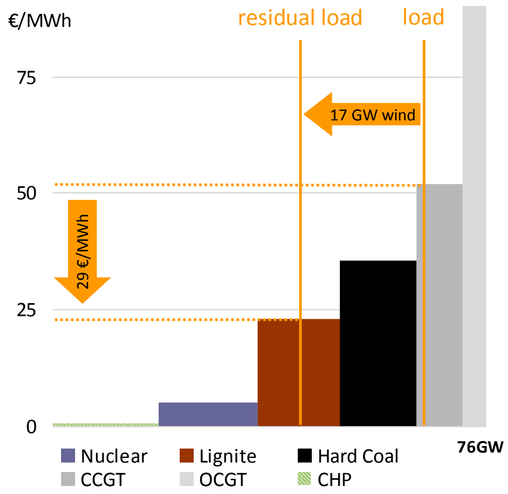

Figure 2. Merit-order effect during a windy hour: VRE in-feed reduces the equilibrium price. Numbers are illustrative.

However, if installed VRE capacity is non-marginal, VRE supply itself reduces the price during windy and sunny hours by shifting the residual load curve to the left (merit-order effect, Figure 2). The more capacity is installed, the larger the price drop will be. This implies that the market value of VRE falls with higher penetration. The figure also suggests that the price drop will be larger if the merit-order curve becomes steeper in the relevant region. The fundamental reason for the merit-order effect is that the short-term supply function is upward sloping because a) there exists a set of generation technologies that differ in their variable-to-fix costs ratio and b) electricity storage is costly.

More generally, it is of course a well-known economic result that the price of a good decreases as supply is increased.

Profile costs have important implications for policy makers, investors, and energy system modelers alike. In a market environment, investors bear profile costs by receiving the market value as income, hence they play a crucial role for investment decisions. However, VRE today are subsidized in most markets and some support schemes result in profile costs becoming an externality. Under renewable portfolio standards (green certificates obligations) or premium feed-in tariffs (FiTs), hourly price signals are passed on to investors. Under other policies, such as fixed FiTs, profile costs are commonly paid by electricity consumers or through government funds.[7] However, since the gap between market revenues and the FiT is filled by subsidies. Thus profile costs matter for policy makers, since their size affects the costs of subsidies.[8] In any case, understanding the market value of VRE at high penetration rates is key evaluating under which conditions subsidies can be phased out.

More fundamentally, under perfect and complete markets, the market value is identical to the marginal economic value that wind power has for society. Hence it is the market value that should be used for welfare, cost-benefit, or competitiveness analyses, and not the base price as in EPIA (2011) and BSW (2011). Ueckerdt et al. (2012) propose a methodology how profile costs can be taken into account in energy system models that lack the high temporal resolution needed to capture them directly.

[7] Countries that use a fixed FiT include Germany, Denmark, and France. Certificate schemes or a premium FiT are used for example in Spain, UK, Sweden, Norway, Poland, and many U.S. states. Germany introduced a premium FiT in 2012; see Sensfuß & Ragwitz (2010) on VRE market value in the context of this policy.

[8] The cost for FiT are often put directly on electricity consumers. In Germany, electricity consumers pay a specific earmarked levy on electricity that is labelled “EEG-Umlage”. Balancing costs and location costs are often covered by subsidy schemes or socialized via grid tariffs.

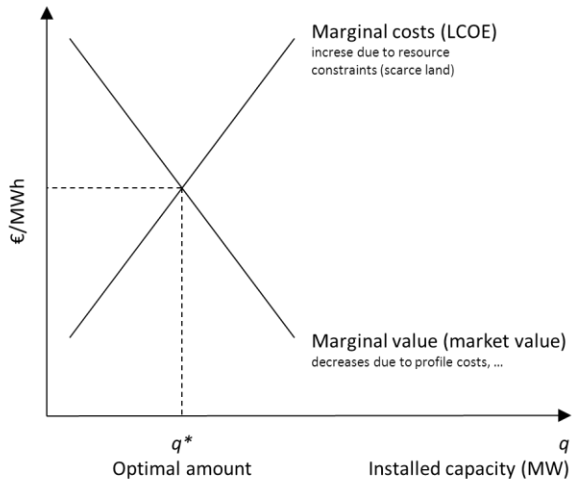

Figure 3. The intersection of long-term marginal costs (LCOE) and the market value gives the optimal amount of VRE (Hirth 2012b).

This paper provides a comprehensive discussion of the market value of VRE within an innovative framework, based on a thorough review of previous publications, new market data analysis, and tailor-made power system modeling. More specifically, it contributes to the literature in five ways. Firstly, we focus on variability and its economic consequence for the market value of VRE, profile costs. We quantify profile costs based on a literature survey, market data, and numerical model results. Secondly, we use relative prices throughout the analysis. Most of the previous literature reports either absolute prices, total system costs, other metrics such as \$/KW, \$/MWa, or \$/m², which are difficult to compare across space, over time, and between studies. More fundamentally, relative prices have a more straightforward economic interpretation. Thirdly, new market data are presented and analyzed econometrically, a novelty to this branch of literature. Fourthly, we develop and apply a new calibrated numerical model: the European Electricity Market Model EMMA. It models hourly prices as well as investment endogenously, covers a large geographical area, allows for international trade, uses high quality wind and solar data, and incorporates crucial technical constraints of the power system. Finally, we identify and quantify the impact of prices and policies on the market value of VRE. By doing so, it is possible to provide a range of estimates that takes into account parameter uncertainty, and to identify integration options that help mitigate the value drop.

The paper is structured as follows. Section 2 reviews the literature. Section 3 presents new market data and regression analysis. Section 4 outlines an electricity market model. Section 5 presents results. Section 6 summarizes the results and section 7 concludes.

2. Literature review

There is extensive literature on the effects of VRE on power markets. A well-known branch of this literature estimates the effect of VRE on the average electricity price (Unger & Ahlgren 2005, Rathmann 2007, Sensfuß 2007, Olsina et al. 2007, Saenz de Miera et al. 2008, Sensfuß et al. 2008, Munksgaard & Morthorst 2008, MacCormack et al. 2010, Jónsson et al. 2010, Woo et al. 2011, O’Mahoney & Denny 2011, Gil et al. 2012, Hirth & Ueckerdt 2012). While some of these papers discuss the effect of VRE deployment on income of conventional generators, they do not report the effect on VRE generators’ income via a change of their relative price. Other studies discuss specific consequences of VRE, such as curtailment (Denholm & Margolis 2007, Revuelta et al. 2011, Tuohy & O’Malley 2011), demand for back-up capacity (Weigt 2009, Mount et al. 2011), or dispatch and cycling of thermal plants (Ummels 2007, Maddaloni et al. 2009, Göransson & Johnsson 2012). Although these are the underlying reasons for integration costs, this literature does not translate technical constraints into price effects. A number of *integration studies* quantifies economic costs of VRE variability, but these publications focus on balancing or grid-related costs while not accounting for profile costs, and seldom report the price impact (Gross et al. 2006, Smith et al. 2007, DeCesaro & Porter 2009, Milligan & Kirby 2009, GE Energy 2010, Holttinen et al. 2011). Balancing markets are discussed in Hirth & Ziegenhagen (2013).

This remainder of this section will discuss the methodologies and findings of the theoretical and empirical literature that focuses more narrowly on the market value of VRE (Table 1).

Table 1: Literature on the market value of VRE

	Theoretical Literature	**Empirical Literature**
Main References	Grubb (1991), Lamont (2008), Twomey & Neuhoff (2008), Joskow (2011)	Lamont (2008), Nicolosi (2012), Mills & Wiser (2012)
Main findings	• comparisons of generating technologies are incomplete when confined to costs (LCOE) → "market test" • market power of conventional generators decreases the relative value of VRE	• value factor of VRE drops with increased penetration (Table 2) At high penetration (>15% wind): • hydro systems have higher VRE value factors than thermal systems • models without high temporal resolution overestimate the value of VRE • models without endogenous investment underestimate the value of VRE

2.1 Theoretical and market power literature

Joskow (2011) and Borenstein (2012) discuss the economics of variability. They conclude that average full costs of different generation technologies, sometimes called the levelized costs of electricity (LCOE), are an incomplete metric to compare dispatchable and non-dispatchable technologies, because the value of electricity depends on the point in time and space it is produced.[9]

Bode (2006), Lamont (2008) and Twomey & Neuhoff (2010) derive analytical expressions for the market value of VRE. While Lamont uses a general functional form for the merit-order curve, Bode assumes it to be linear and Twomey & Neuhoff to be quadratic. Lamont shows that the market value of VRE can be expressed as the base price and an additive term that is a function of the covariance of VRE generation and power prices. It is important to note that the covariance is not a static parameter, but a function of wind power penetration. Overall, the main contribution of the theoretical literature has been to stress the fundamental economic differences between dispatchable and VRE technology.

Twomey & Neuhoff (2010), Green & Vasilakos (2010), and Sioshansi (2011) analyze VRE market value in the context of market power of conventional generators, applying Cournot or supply function equilibrium theory. In times of little VRE supply, strategic generators can exercise market power more effectively, implying that mark-ups on competitive prices are inversely correlated with VRE infeed. Thus market power tends to reduce the value factor of VRE. Twomey & Neuhoff (2010) report

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

that in a duopoly of conventional generators that engage in optimal forward contracting, the wind value factor is 0.7, as compared to 0.9 in a competitive setting.

2.2 Empirical literature

There is a long tradition of quantifying market effects of VRE, emerging in the 1980s. This empirical literature is quite heterogeneous with respect to methodology and focus. Some studies have a very broad scope and report profile costs as one of many results, while other focus on VRE market value. Results are reported in a variety of units and often in absolute terms. Furthermore, the literature is scattered in economic and engineering journals, with very little cross-referencing, and few papers provide a thorough literature review. In this subsection, we aim to give an overview of the literature, and extract quantifications of value factors from previous studies. Therefore, value factors were calculated from reported data whenever possible. Studies are clustered according to the approach they use to estimate electricity prices: historical market prices, shadow prices from short-term dispatch models, or shadow prices from long-term models that combine dispatch with endogenous investment.

Historical Prices

To derive value factors from historical data, it is sufficient to collect hourly electricity prices and synchronous VRE in-feed, as done in section 3. The drawback of this approach is that results are limited to the historical market conditions, especially historical penetration rates.

Borenstein (2008) estimates the solar value factor in California to be 1.0 – 1.2, using 2000-03 prices and a synthetic generation profile. Sensfuß (2007) and Sensfuß & Ragwitz (2011) estimate the wind value factor in Germany to drop from 1.02 to 0.96 between 2001 and 2006, when the wind share grew from 2% to 6% and the solar value factor to fall from 1.3 to 1.1 between 2006 and 2009. Green & Vasilakos (2012) calculate value factors on a monthly basis, instead of an yearly one. They estimate the wind value factor to be 0.92 in West Denmark and 0.96 in East Denmark during the last decade. They also calculate the costs of converting Danish wind generation into a constant supply of electricity by means of imports and exports to Norway to be 3-4% of its market value. Fripp & Wiser (2008) estimate the value of wind at different sites in the Western US. Because the correlation effect varies between sites, value factors differ between 0.9 and 1.05.

Some studies use locational electricity prices to estimate grid-related costs. Brown & Rowlands (2009) estimate the solar value factor in Ontario to be 1.2 on average, but 1.6 in large cities. Lewis (2010) estimates the value factor to vary between 0.89 and 1.14 at different locations in Michigan.

Shadow Prices from (Short-Term) Dispatch Models

To derive value factors under conditions other than those which have been historically observed, electricity prices can be derived from dispatch models. However, since by definition the capacity mix remains constant, pure dispatch modeling does not account for changes in the capital stock triggered by higher VRE penetration. Thus, historical market data and dispatch models can only deliver estimates of the short-term market value of VRE. The models applied in the literature vary starkly in terms of sophistication and temporal resolution.

More than 20 years ago, Grubb (1991a, 1991b) used analytical approximations and UK data to estimate the market value of wind power to be between 0.75 – 0.85 at 30% penetration rate. Rahman & Bouzguenda (1994), based on Bouzuenda & Rahman (1993) and Rahman (1990), estimated the value of solar energy to be around 90-100 $/MWh at low penetration rates. They report the value to drop dramatically when solar capacity increases beyond 15% of installed capacity. Hirst & Hild (2004) model a small power system with a short-term unit commitment model and report the value factor to drop from 0.9 to 0.3 as wind power increases from zero to 60% of installed capacity. ISET et al. (2008) and Braun et al. (2008) use a simple three-technology model to estimate the value of solar power in Germany, but report only absolute prices. Obersteiner et al. (2009) estimate wind value factors for Austria. Assuming a polynomial merit-order curve they estimate the value factor to be 0.4 – 0.9 at 30% market share, depending on the order of the polynomial. Obersteiner & Saguan (2010) use a cost-based merit-order curve and report the wind value factor to drop from 1.02 to 0.97 as the market share in Europe grows from zero to 6%. Green & Vasilakos (2011) report a low UK wind value factors of 0.45 at 30GW installed capacity. Energy Brainpool (2011) forecast market values for hydro, onshore and offshore wind, and solar power in Germany until 2016, finding a drop of the onshore value factor to 0.84 while the offshore factor remains more stable at 0.97 due to its flatter generation profile. Valenzuela & Wang (2011) show how crucial temporal resolution affects the results: increasing the number of time steps from 16 to 16,000 reduces the wind value factor from 1.4 to 1.05, a bias that is confirmed by Nicolosi et al. (2011) and Nicolosi (2012).

Shadow Prices from (Long-Term) Dispatch and Investment Models

Introducing significant amounts of wind and solar power to the market alters the structure of electricity prices and incentives investors to react by building or decommission power plants. To take into account investor response to VRE and to derive long-term value factors one needs to model investment endogenously.

Martin & Diesendorf (1983), estimating the absolute market value of wind power in the UK, find that the value of wind power decreases by a quarter as installed capacity in the UK increases from 0.5 GW to 8 GW. They do not report the base price, hence value factors cannot be derived. Lamont (2008) uses Californian generation and load profiles, reporting the wind value factors to drop from 0.86 to 0.75 as its market share increases from zero to 16%, and solar value factors to drop from 1.2 to 0.9 as its share rises to 9%. Bushnell (2010) finds that wind revenues are reduced by 4-15% as the wind share increases from zero to 28% in the Western US, but doesn't provide value factors. Gowrisankaran et al. (2011) compare the revenues of solar power in Arizona to LCOE of a gas plant, which is a proxy for the long-term equilibrium base price. As the solar market share grows from 10% to 30%, the value factor drops from 0.9 to 0.7. These four models are long-term in the sense that all investment is endogenous.

Other studies combine endogenous investment with an existing plant stack, an approach that we will label “mid-term” in section 4.3. Swider & Weber (2006) apply a stochastic dispatch and investment model to Germany and report the wind value factor to drop from 0.9 to 0.8 as penetration increases from 5% to 25%. Kopp et al. (2012) model wind value factors of 0.7 – 0.8 at 39% penetration. Nicolosi (2012) uses a sophisticated model of the European electricity market to estimates both the wind and the solar value factors in Germany. He reports them to drop from roughly unity to 0.7 as installed capacities increase to 35% and 9% market share, respectively. Nicolosi finds a comparable drop when using data from Texas. Mills & Wiser (2012) apply a similarly elaborated mid-term model to California, finding comparable results: the wind value factor drops to 0.7 at 40% penetration. Since electricity demand for cooling is better correlated with solar generation, the solar value factor is higher in California than in Germany – but it also drops dramatically with increased solar shares, despite the flexible hydro capacity available in California dampens the drop of value factors somewhat. Mills & Wiser also model concentrated solar power and find that at high penetration rates, thermal energy storage increases its value significantly. Because of their sophisticated and well-documented models, the studies by Nicolosi and Mills & Wiser will serve as point of reference for the model results presented in section 5. All results are summarized in Table 2, Figure 4, and Figure 5.

Table 2: Empirical literature on the market value of VRE

Prices	Reference	Technology	Region	Value Factors Estimates (at different market shares)
Historical Prices	Borenstein (2008)	Solar	California	1.0 – 1.2 at different market design (small)
	Sensfuß (2007), Sensfuß & Ragwitz (2011)	Wind Solar	Germany	1.02 and 0.96 (2% and 6%) 1.33 and 1.14 (0% and 2%)
	Fripp & Wiser (2008)	Wind	WECC	0.9 – 1.05 at different sites (small)
	Brown & Rowlands (2008)	Solar	Ontario	1.2 based on system price (small)
	Lewis (2010)	Wind	Michigan	0.89 – 1.14 at different nodes (small)
	Green & Vasilakos (2012)	Wind	Denmark	*only monthly value factors reported*
Prices from Dispatch Model	Grubb (1991a)	Wind	England	0.75-0.85 (30%) and 0.4-0.7 (40%)
	Rahman & Bouzguenda (1994) Rahman (1990), Bouzguenda & Rahman (1993)	Solar	Utility	*only absolute value reported*
	Hirst & Hild (2004)	Wind	Utility	0.9 – 0.3 (*0% and 60% capacity/peak load*)
	ISET et al. (2008), Braun et al. (2008)	Solar	Germany	*only absolute value reported*
	Obersteiner & Saguan (2010) Obersteiner et al. (2009)	Wind	Europe	1.02 and 0.97 (0% and 6%)
	Boccard (2010)	Wind	Germany Spain Denmark	.87 – .90 (6-7%) .82 – .90 (7-12%) .65 – .75 (12-20%)
	Green & Vasilakos (2011)	Wind	UK	0.45 (20%)
	Energy Brainpool (2011)	Onshore Offshore Hydro Solar	Germany	0.84 (12%) 0.97 (2%) 1.00 (4%) 1.05 (6%)
	Valenzuela & Wang (2011)	Wind	PJM	1.05 (5%)
Dispatch & Investment Model	Martin & Diesendorf (1983)	Wind	England	*only absolute value reported*
	Swider & Weber (2006)	Wind	Germany	0.93 and 0.8 (5% and 25%)
	Lamont (2008)	Wind Solar	California	0.86 and 0.75 (0% and 16%) 1.2 and 0.9 (0% and 9%)
	Bushnell (2010)	Wind	WECC	*no prices reported*
	Gowrisankaran et al. (2011)	Solar	Arizona	0.9 and 0.7 (10% and 30%)
	Mills & Wiser (2012) Mills (2011)	Wind Solar	California	1.0 and 0.7 (0% and 40%) 1.3 and 0.4 (0% and 30%)
	Nicolosi (2012)	Wind Solar Wind	Germany Germany ERCOT	0.98 and 0.70 (9% and 35%) 1.02 and 0.68 (0% and 9%) .74 (25%)
	Kopp et al. (2012)	Wind	Germany	0.93 (19%) and 0.7-0.8 (39%)

These publications usually do not use terms “profile cost” or “utilization effect”. Output was re-calculated to derive yearly value factors.

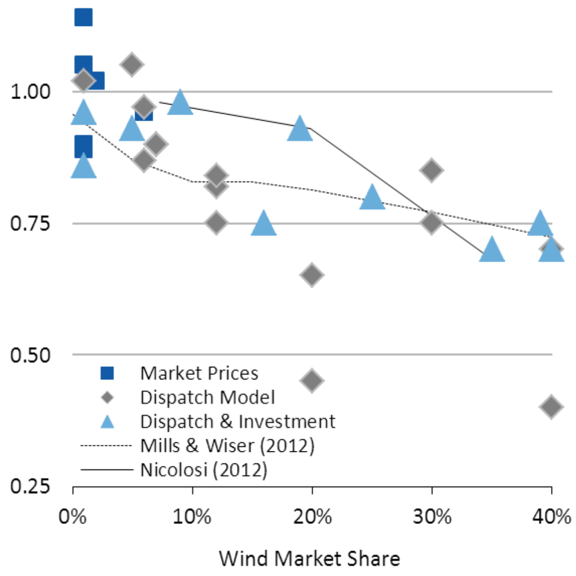

Figure 4. Wind value factors as reported in the literature.

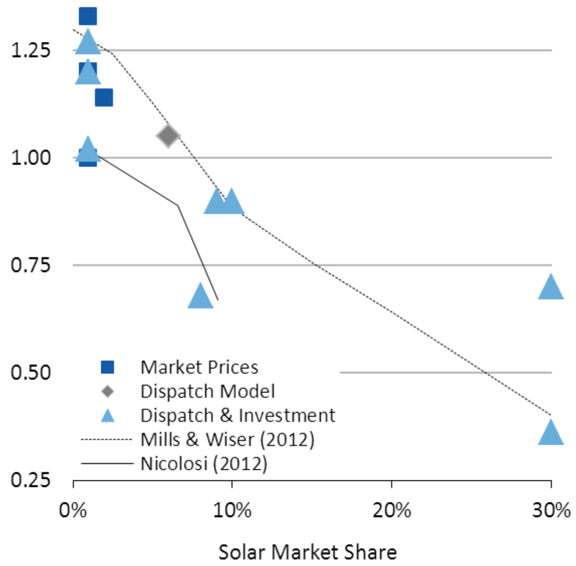

Figure 5. Solar value factors as reported in the literature.

Summing up the literature review, at low penetration rates, wind value factors are reported to be close to unity and solar value factors are somewhat higher. Wind value factors are estimated to drop to around 0.7 at 30% market share. Solar value factors are reported to drop faster, so they reach 0.7 at 10-15% penetration rate, albeit there is large variation both in wind and solar value factors.

The literature some methodological conclusions as well: to estimate value factors at high market shares, more recent studies rely on endogenous investment modeling while taking the existing capital stock into account. Keeping the capacity mix constant would downward-bias the VRE value factor. Several papers emphasize the importance of high temporal resolutions and report that low-resolution models overestimate the value of VRE. Only few of the models features reservoir hydro power (Rahman & Bouzguenda 1994, Mills & Wiser 2012, Nicolosi 2012), and those treat hydro power in a relatively stylized way. This can be seen as a serious shortcoming of the literature, since hydro provides a potentially important source of flexibility. It might be worthwhile to note that there is a strong methodological focus on numerical modeling, while other empirical methods such as regression analysis are not used. Finally, only half of the reviewed studies are published in peer-reviewed journals.

3. Market Data

In this section, historical VRE value factors are calculated ex-post from observed VRE in-feed data and market prices. In contrast to most previous studies (Borenstein 2008, Sensfuß 2007, Fripp & Wiser 2008, Brown & Rowlands 2008), actual instead of estimated VRE generation data are used, and results are provided for a number of different markets. These value factors are then used to estimate the impact of penetration on market value econometrically, a novelty in this branch of the literature.

3.1 A Formal Definition of Value Factors

To start with, value factors are formally defined. The base price $\overline{p}$ is the time-weighted average wholesale day-ahead price. In matrix notation,

$$\bar{p} = (\mathbf{p}'\mathbf{t})/(\mathbf{t}'\mathbf{t}) \quad (1)$$

where $\mathbf{p}_{(Tx1)}$ is a vector of hourly spot prices and $\mathbf{t}_{(Tx1)}$ a vector of ones**,** both with dimensionality $(Tx1)$ where T is the number of hours. The average revenue of wind power or "wind price" $\bar{p}^{w}$ is the wind-weighted spot price,

$$\bar{p}^{w} = (\mathbf{p}'\mathbf{g})/(\mathbf{g}'\mathbf{t}) \quad (2)$$

where the generation profile $\mathbf{g}_{(Tx1)}$ is a vector of hourly generation factors that sum up to the yearly full load hours (FLH). Accordingly, $\mathbf{p'g}$ is the yearly revenue and $\mathbf{g't}$ the yearly generation.[10] The wind value factor v^{w} is defined as the ratio of average wind revenues to the base price:

$$v^{w} = \bar{p}^{w} / \bar{p} \quad (3)$$

This definition relies on day-ahead prices only and ignores other market channels such as future and intraday markets (discussed in Obersteiner & von Bremen 2009). The solar value factor is defined analogously. Here, value factors are calculated for each year, while others have used different periods (Green & Vasilakos 2012, Valenzuela & Wang 2011). Using longer periods tends to lower the value factor if VRE generation and demand are not correlated over these time scales.

3.2 Descriptive Statistics

In the following, wind and solar value factors are calculated for Germany and wind value factors for a number of countries. Day-ahead spot prices were taken from various power exchanges. Generation profiles were calculated as hourly in-feed over installed capacity. In-feed data come from transmission system operators (TSOs) and capacity data from TSOs as well as public and industry statistics. Installed wind capacity is usually reported on a yearly basis and was interpolated to account for changes during the year. Because solar capacity has changed rapidly, daily capacity data was used. For earlier years, German in-feed data were not available, consequently proxies were used.[11] The market share of wind m^{w} is wind power generation over total electricity consumption.

Table 3 reports descriptive statistics for Germany. At low penetration rates, the wind value factor was slightly above unity and the solar factor around 1.3. This can be explained by the positive correlation of VRE with demand (correlation effect): solar power correlates positively with electricity demand on a diurnal scale and wind power on a seasonal scale. As wind's market share rose from 2% to 8% from 2001-12, its value factor declined by 13 percentage points. Similarly, an increase of the solar market share from zero to 4.5% led to a decline of its value factor by 28 percentage points. These drops are primarily caused by the merit-order effect (see also Figure 6).

Historical market data indicates that the merit-order effect significantly reduced the market value of VRE, even at modest market shares in the single digit range.

[10] This nomenclature can be easily generalized for price periods of unequal lengthy (by changing the ones in $\mathbf{t}$ to non-uniform temporal weights) and, more importantly, to account for spatial price and wind variability and grid-related costs (see Appendix A).

[11] Price data were obtained from the electricity exchanges EPEX-Spot, Nordpool, and APX. In-feed data come from the TSOs Statnett, Svenska Kraftnät, Energienet.dk, 50 Hertz, Amprion, TenneT, EnWG, and Elia. Installed capacities were taken from BMU (2011), BNetzA Stammdatenbank (2012), World Wind Energy Association (2011), and European Wind Energy Association (2011). All data are available as supplementary material to the online version of this article. German solar data for 2008-10 are proxied with 50Hertz control area data. Generation in Germany correlates very well with generation in the 50Hertz area $\rho = 0.93$, so the proxy seems appropriate. Wind profiles from 2001-06 are taken from Sensfuß (2007) and Solar profiles 2006-07 from Sensfuß & Ragwitz (2011).

Table 3: Base price, average revenue, market value, and market share for wind and solar power in Germany.

		Wind				Solar		
	$\bar{p}$ (€/MWh)	$\bar{p}^w$ (€/MWh)	v^w (1)	m^w (%)	$\bar{p}^s$ (€/MWh)	v^s (1)	m^s (%)
2001	24	25*	1.02	2.0	-	-	0.0
2004	29	29*	1.00	3.0	-	-	0.1
2005	46	46*	.99	3.5	-	-	0.2
2006	51	49*	.96	4.7	68**	1.33	0.4
2007	38	33	.88	4.9	44**	1.16	0.5
2008	66	60	.92	5.5	82***	1.25	0.7
2009	39	36	.93	7.1	44***	1.14	1.1
2010	44	42	.96	7.3	49***	1.11	2.1
2011	51	48	.93	8.8	56	1.10	3.3
2012	43	38	.89	8.0	45	1.05	4.5
Average	**43**	**40**	**0.94**	**5.6**	**55**	**1.16**	**1.8**

* Estimates from Sensfuß (2007)
** Estimates from Sensfuß & Ragwitz (2011)
*** Market data for 50Hertz control area.
Market for Germany data otherwise.

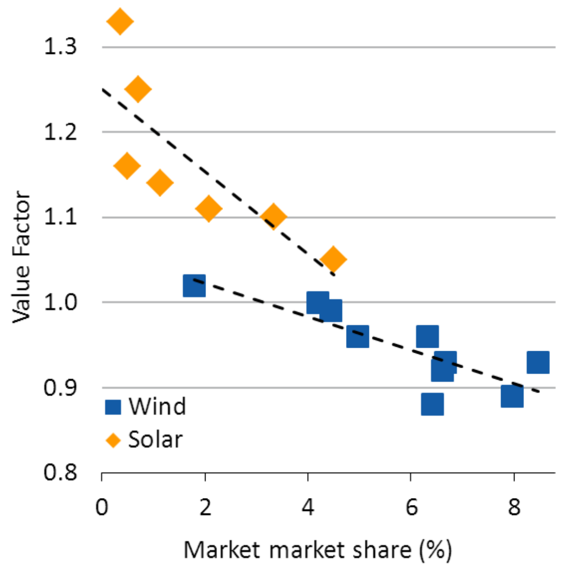

Figure 6. Historical wind and solar value factors in Germany (as reported numerically in Table 3).

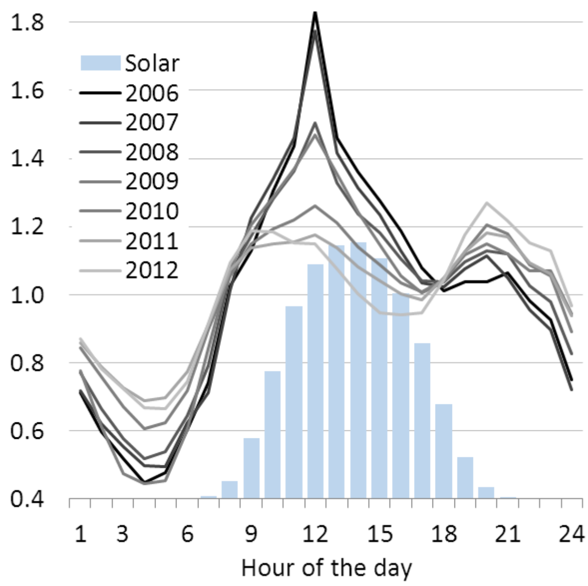

Figure 7. The daily price structure in Germany during summers from 2006 – 2012. The bars display the distribution of solar generation over the day.

An alternative way of visualizing the impact of solar generation on relative prices is to display the daily price structure (Figure 7). As 30 GW solar PV capacity was installed over the years, prices between 8 a.m. and 6 p.m. fell relative to the prices at night. While the price at noon used to be 80% higher than the average price, today it is only about 15% higher.

Table 4 shows wind value factors for different European countries. Value factors are close to unity in the Nordic countries, where large amounts of flexible hydro generation provide intertemporal flexibility and reduce short-term price fluctuations. In thermal power systems, such as in Germany, VRE value factors are more sensitive to penetration rates. The strong interconnections between Denmark and the Nordic countries keep the Danish value factors from dropping further.

Table 4: Wind value factors 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
2010	0.94	0.96	0.99	1.01	1.03
2011	0.92	0.94	0.93	n/a	n/a
2012	0.89	0.90	0.90	n/a	n/a
Average	**0.91**	**0.92**	**0.95**	**1.01**	**1.01**

3.3 Econometrics

A simple regression model is applied to estimate the impact of increasing penetration rates on value factors. Based on the theoretical arguments from section 1, we hypothesize that higher market shares reduces the value factor, and that the drop is more pronounced in thermal systems. The regression model includes the market share of wind power, a dummy for thermal system that interacts with the share (such that the impact of market share in thermal systems is β_1 and in thermal system $\beta_1 + \beta_2$), and time dummies as control variables to capture supply and demand shocks:

$$v_{t,c}^{w} = \beta_0 + \beta_1 \cdot share_{t,c} + \beta_2 \cdot share_{t,c} \cdot thermal_c + \beta_3 \cdot thermal + \varepsilon_{t,c} \quad (4)$$

where $\varepsilon \sim iid(0,\sigma^2)$ and t,c are indices for time and countries, respectively. The model is specified as a random effects model and estimated using OLS. The model formulation is equivalent to estimating thermal and hydro systems separately.

The results, which are summarized in table 5, are striking: increasing the market share of wind by one percentage point is estimated to reduce the value factor by 0.22 percentage points in hydro systems β_1 and by 1.62 percentage points in thermal systems $\beta_1 + \beta_2$. The wind value factor without any installed wind capacity is estimated to be 0.98 in hydro systems β_0 and 1.04 in thermal systems $\beta_0 + \beta_4$. All coefficients are significant at the 5%-level.

Table 5: Regression results

Dependent variable	Wind value factor (%)
Share of wind power (% of consumption)	-0.26** (3.5)
Share of wind power * Thermal dummy	-1.36** (3.2)
Constant	98.3*** (82.5)
Thermal dummy	0.06**

	(2.1)
R^2	.51
Number of obs	30

*** significant at 1% level; ** significant at 5% level; absolute t-values in brackets

However, there are several reasons to suspect biased estimates and to treat results cautiously. The number of observations is very mall. Penetration rates are small compared to expected long-term levels and it is not clear that results can be extrapolated. Furthermore, power systems might adapt to increasing penetration rates. Finally, in the past, exporting electricity during windy times has helped German and Danish value factors to stabilize. In the future, when similar amounts of VRE are installed in surrounding markets, there will be much less potential to benefit from trade and value factors might drop more.

4. Numerical Modeling Methodology

This section introduces the European Electricity Market Model EMMA, a stylized numerical dispatch and investment model of the interconnected Northwestern European power system. In economic terms, it is a partial equilibrium model of the wholesale electricity market. EMMA has been developed specifically to estimate value factors at various penetration rates, under different prices and policies, and in the medium-term as well as the long-term equilibrium. Model development followed the philosophy of keeping formulations parsimonious while representing VRE variability, power system inflexibilities, and flexibility options with appropriate detail. This section discusses crucial features verbally. All equations and input data can be found in the Appendix B. Model code and input data are available for download as supplementary material to the online version of this article.

4.1 The electricity market model EMMA

EMMA minimizes total costs with respect to investment, production and trade decisions under a large set of technical constraints. Markets are assumed to be perfect and complete, such that the social planner solution is identical to the market equilibrium. Hence, the market value represents both the marginal benefit to society as well as the income that an investor earns on the market. The model is linear, deterministic, and solved in hourly time steps for one year.

For a given electricity demand, EMMA minimizes total system cost, the sum of capital costs, fuel and CO_2 costs, and other fixed and variable costs, for generation, transmission, and storage. Capacities and generation are optimized jointly. Decision variables comprise the hourly production of each generation technology including storage, hourly electricity trade between regions, and investment and disinvestment in each technology. The important constraints relate to electricity demand, capacity limitations, and the provision of district heat and ancillary services.

Generation is modeled as eleven discrete technologies with continuous capacity: two VRE with zero marginal costs – wind and solar –, six thermal technologies with economic dispatch – nuclear, lignite, hard coal, combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT), and lignite carbon capture and storage (CCS) –, a generic “load shedding” technology, and pumped hydro storage. Hourly VRE generation is limited by generation profiles. Dispatchable plants produce whenever the price is above their variable costs. Storage is optimized endogenously under turbine, pumping, and inventory constraints. Existing power plants are treated as sunk investment, but are decommissioned if they do not cover their quasi-fixed costs. New investments have to recover their annualized capital costs from short-term profits.

The hourly electricity price is the shadow price of demand. In other words, we model an energy-only market with scarcity pricing, assuming perfect and complete markets. This guarantees that in the long-term equilibrium, the zero-profit condition holds. Curtailment of VRE is possible at zero costs, which implies that the electricity price cannot become negative.

Demand is exogenous and assumed to be perfectly price inelastic at all but very high prices, when load is shed. Price-inelasticity is a standard assumption in dispatch models due to their short time scales. While investment decisions take place over longer time scales, we justify this assumption with the fact that the average electricity price does not vary dramatically between model scenarios.

Combined heat and power (CHP) generation is modeled as must-run generation. A certain share of the cogenerating technologies lignite, hard coal, CCGT and OCGT are forced to run even if prices are below their variable costs. The remaining capacity of these technologies can be freely optimized. Investment and disinvestment in CHP generation is possible, but the total amount of CHP capacity is fixed. Ancillary service provision is modeled as a must-run constraint for dispatchable generators.

Cross-border trade is endogenous and limited by net transfer capacities (NTCs). Investments in interconnector capacity are endogenous to the model. As a direct consequence of our price modeling, interconnector investments are profitable if and only if they are socially beneficial. Within regions transmission capacity is assumed to be non-binding.

The model is linear and does not feature integer constraints. Thus, it is not a unit commitment model and cannot explicitly model start-up cost or minimum load. However, start-up costs are parameterized to achieve a realistic dispatch behavior: assigned base load plants bid an electricity price below their variable costs in order to avoid ramping and start-ups.

Being highly stylized, the mode has important limitations. The most significant caveat might be the absence of hydro reservoir modeling. Hydro power offers intertemporal flexibility and can readily attenuate VRE fluctuations. Similarly, demand response in the form of demand shifting or an elastic demand function would help to integrate VRE generation. Technological change is not modeled, such that generation technologies do not adapt to VRE variability. Ignoring these flexibility resources leads to a downward-bias of VRE market values, thus results should be seen as conservative estimates.

EMMA is calibrated to Northwestern Europe and covers Germany, Belgium, Poland, The Netherlands, and France. In a back-testing exercise, model output was compared to historical market data from 2008-10. Crucial features of the power market can be replicated fairly well, like price level, price spreads, interconnector flows, peak / off-peak spreads, the capacity and generation mix. Wind value factors are replicated sufficiently well (Table 6). Solar value factors are somewhat below market levels, probably because of the limited number of generation technologies.

Table 6: Value factors in Germany

	Wind		**Solar**	
	model	market	model	market
2008	0.93	0.92	1.04	1.25
2009	0.95	0.93	1.03	1.14
2010	0.94	0.96	0.98	1.11

4.2 Input Data

Electricity demand, heat demand, and wind and solar profiles are specified for each hour and region. Historical data from the same year (2010) are used for these time series to preserve empirical temporal and spatial correlation of and between parameter as well as other statistical properties. These correlations crucially determine the market value of renewables. Unlike in section 3, VRE profiles are not based on historical in-feed, which is not available for all countries. Instead, historical weather data from the reanalysis model ERA-Interim and aggregate power curves are used to derive profiles. Details on this procedure and the statistical properties of VRE are discussed in Hirth & Müller (2013). Wind load factors in all countries are scaled to 2000 full load hours. Load data were taken from various TSOs. Heat profiles are based on ambient temperature.

Fixed and variable generation costs are based on IEA & NEA (2010), VGB Powertech (2011), Black & Veatch (2012), and Nicolosi (2012). Fuel prices are average 2011 market prices and the CO_2 price is 20 €/t. Summer 2010 NTC values from ENTSO-E were used to limit transmission constraints. CHP capacity and generation is from Eurelectric (2011b). A discount rate of 7% is used for all investments, including transmission, storage and VRE.

4.3 Long-term vs. Short-term Market value

The market value of VRE depends crucially on assumptions regarding the previously-existing capital stock. In the following, we discuss three alternatives that are found in the literature.

One option is to take the existing generation and transmission infrastructure as given and disregard any changes to that. The optimization reduces to a sole dispatch problem. We label this the *short-term* perspective. Another possibility is to disregard any existing infrastructure and optimize the electricity system "from scratch" as if all capacity was green-field investment. This is the *long-term* perspective. Finally, one can take the existing infrastructure as given, but allow for endogenous investments and disinvestments. We call this the *medium term*. A variant of the mid-term framework is to account only for a share of existing capacity, for example, only those plants that have not reached their technical life-time (*transition*). In section 5 we present mid-term and long-term results.

For the short, mid, and long-term framework corresponding welfare optima exists, which are, if markets are perfect, identical to the corresponding market equilibria. It is only in the long-term equilibrium that all profits are zero (Steiner 1957, Boiteux 1960, Crew et al. 1995, Hirth & Ueckerdt 2012). Note that the expressions short term and long term are *not* used to distinguish the time scale on which dispatch and investment decisions take place, but refer to the way the capital stock is treated.

Under perfect and complete markets and inelastic demand, the market value of VRE equals marginal cost savings in the power system. Under a short-term paradigm, adding VRE capacity reduces variable costs by replacing thermal generation – Grubb (1991a) calls the short-term market value "marginal fuel-saving value". In a long-term framework, VRE additionally reduces fixed costs by avoiding investments. In a mid-term setup, VRE reduces only quasi-fixed costs if plants are decommissioned, but cannot reduce the capital costs of (sunk) capital. Typically the long-term value of VRE is higher than the mid-term value.

Table 7: Analytical frameworks

	Short term (Static)	**Medium term / Transition**	**Long term (Green Field)**
Existing Capacity	included	included / partially included	not included
(Dis)investment	none	endogenous / exogenous	-

VRE cost savings	variable costs (fuel, variable O&M, CO_2)	• variable costs • quasi-fixed costs (if incumbent plants are decommissioned) • fixed costs (if new plants are avoided)	variable and fixed costs
Long-term profits	positive or negative	• zero or negative for incumbent capacity • zero for new capacity	zero
References (examples)	studies based pure dispatch models (Table 2)	Swider & Weber (2006), Rosen et al. (2007), Neuhoff et al. (2008), Short et al. (2011), Haller et al. (2011), Mills & Wiser (2012), Nicolosi (2012)	Martin & Diesendorf (1983), DeCarolis & Keith (2006), Lamont (2008), Bushnell (2010), Green & Vasilakos (2011)

Quasi-fixed costs are fixed O&M costs. Fixed costs are quasi-fixed costs plus investment (capital) costs.

5. Model Results

The model introduced in the previous section is now used to estimate VRE market values at various penetration levels. For each given level of VRE, a new equilibrium is found in the rest of the system. This is done both in a mid-term and a long-term framework. Furthermore, the effects of a number of policies, prices, and parameters are discussed. Of course all findings should be interpreted cautiously, keeping model shortcomings and data limitations in mind. Specifically, only the market shares of VRE are increased. A broader renewables mix with hydro power and biomass would have different effects. "(Market) share" is used interchangeably with "penetration (rate)" and is measured as generation over final consumption. Prices are calculated as the load-weighted average across all six countries, unless stated otherwise.

5.1 Mid-term wind market value

At low penetration levels, the wind value factor is 1.1 (Figure 8). In other words, the correlation effect increases the value of wind power by ten percent. However, with higher market share, the value factor drops significantly, reaching 0.5 at 30% penetration. In other words, at 30% penetration, electricity from wind is worth only half of that from a constant source of electricity. This is the merit-order effect at work. The slope of the curve is very similar to the estimated coefficient for thermal systems in section 3 (on average 1.8 percentage points value factor drop per percentage point market share compared to 1.6).

In absolute terms, wind's market value drops even quicker (Figure 9): the average income of wind generators falls from 73 €/MWh to 18 €/MWh as base price drops from 66 €/MWh to 35 €/MWh. To put this into context, we compare this to the generation costs of wind that shrink at a hypothesized learning rate of five percent.[12] Model results indicate that falling revenues overcompensate for falling costs: the gap between costs and revenues remains open, and indeed increases. Under these assumptions, wind power does not become competitive.

[12] We assume that full costs are today 70 €/MWh, the global learning rate is 5%, and that global capacity doubles twice as fast as European capacity. This implies that the LCOE would drop to 60 €/MWh at 30% market share.

Looking at the results from a different angle, costs would need to drop to 30 €/MWh to allow 17% market share without subsidies. From another perspective, with a value factor of 0.5 and LCOE of 60 €/MWh, the base price has to reach 120 €/MWh to make 30% wind competitive.

Here, the market value for wind is estimated for given penetration levels. One can turn the question around and estimate the cost-optimal (or market equilibrium) amount of wind power, which we do in a related paper (Hirth 2012b).

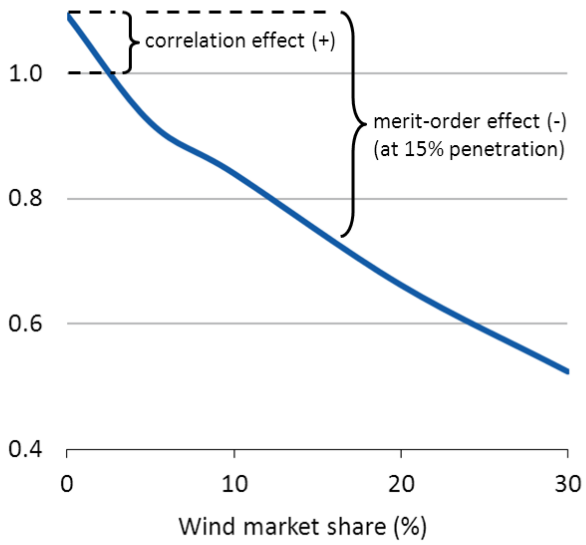

Figure 8. Mid-term value factor of wind.

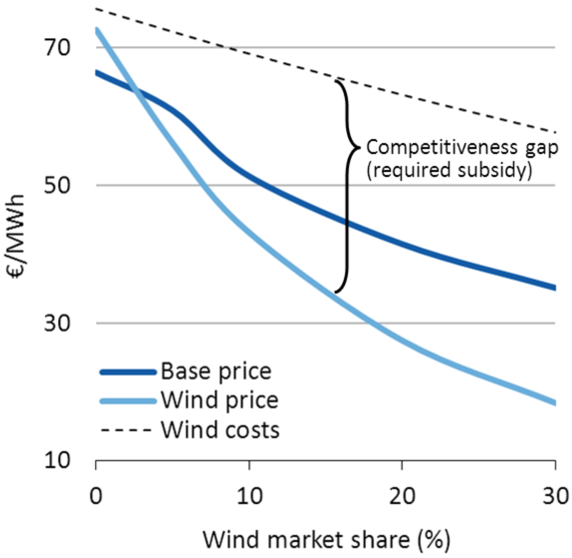

Figure 9. Mid-term absolute market value, compared to the base price and indicative LCOE under learning.

Figure 10 displays the capacity mix with increasing wind shares. At 30%, equivalent to 200 GW of wind power, total dispatchable capacity reduces only by 40 GW. While the profitability of peak load plants increases and the profitability of base load technologies is reduced, the shifts are too small to trigger new investments. Remarkably, there is no investment in storage, and interconnector investments are moderate (about 50% higher capacity than today, of which two thirds can be attributed to wind power).

The value drop can be explained by the shift in price-setting technologies. Figure 11 shows the share of hours of the year in which each generation technology sets the electricity price by being the marginal generator. The share of low-variable cost dispatchable technologies such as lignite and nuclear increases with higher wind deployment, the reason being that residual load is often reduced enough to make these technologies price setting. At 30% wind market share the price drops to zero during 1000 hours of the year, when must-run generation becomes price-setting. Because these are precisely the hours when much wind power is generated, 28% of all wind power is sold at a price of zero.

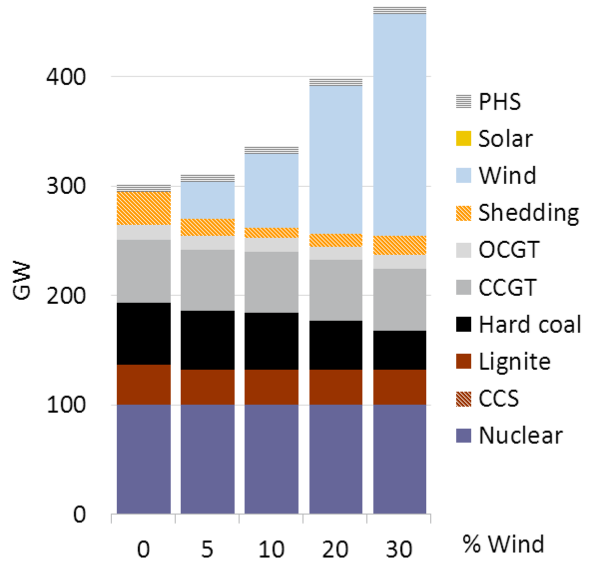

Figure 10. Capacity development for given wind capacity. One reason for the drop in value is that wind power is less and less capable of replacing dispatchable capacity.

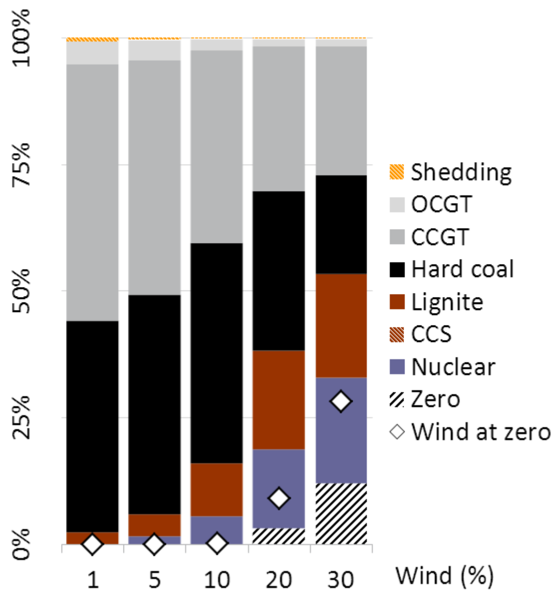

Figure 11. Price-setting technology as a share of all hours (bars) and the share of wind energy that is sold at zero price (diamonds).

The value factors for individual countries are similar to the regional value, with one exception (Figure 12). France has a large fleet of nuclear power plants. When adding wind power to the system, the price drops quickly to the low variable costs of nuclear during wind hours. As a consequence, the value factor drops quicker than the other markets. Model results are robust to the choice of the wind year (Figure 13).

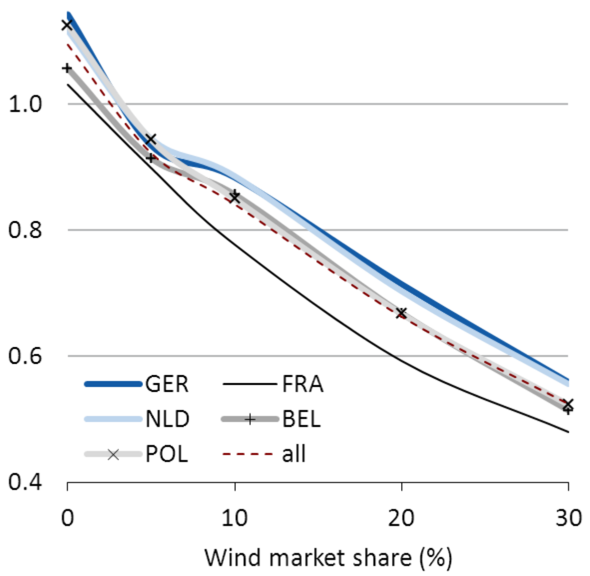

Figure 12. Wind value factors in individual countries.

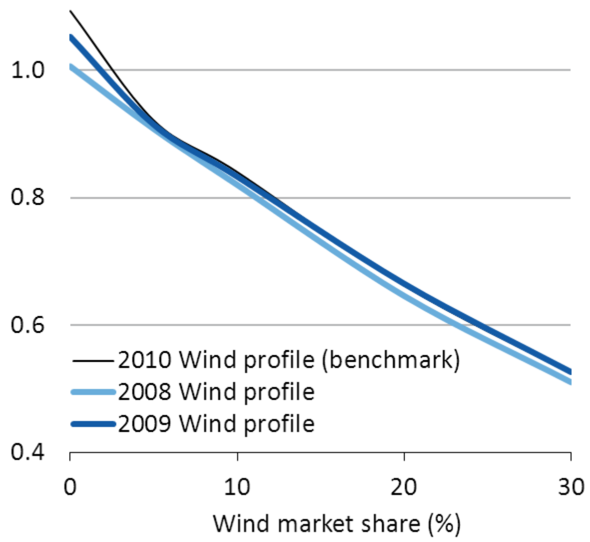

Figure 13. Wind profiles from different years lead to almost exactly the same value factors.

5.2 Mid-term solar market value

The high market value of solar power that is observed on markets might suggest that solar's market value is more stable than wind's. Model results indicate that this is not the case. Its value factor actually drops slightly below 0.5 already at 15% market share (Figure 14). However, one must keep in mind that unlike in the case of wind, the model is not able to replicate the high solar value factor that markets indicate for low penetrations. Even at a learning rate of 10% solar LCOE remain above market value.[13]

The steep drop of solar market value confirms previous studies (Borenstein 2008, Gowrisankaran et al. 2011, Nicolosi 2012, Mills & Wiser 2012) and consistent with historical German market data (recall Figure 5 and Figure 6). This can be explained with the fundamental characteristics of solar power. The solar profile is more "peaky" than wind, with a considerable amount of generation concentrated in few hours. This is shown in Figure 15, which displays the sorted hourly distribution of one MWh generated from wind and solar during the course of one year.

In the remainder of this section we will focus on wind power. Solar value factors are available from the author upon request.

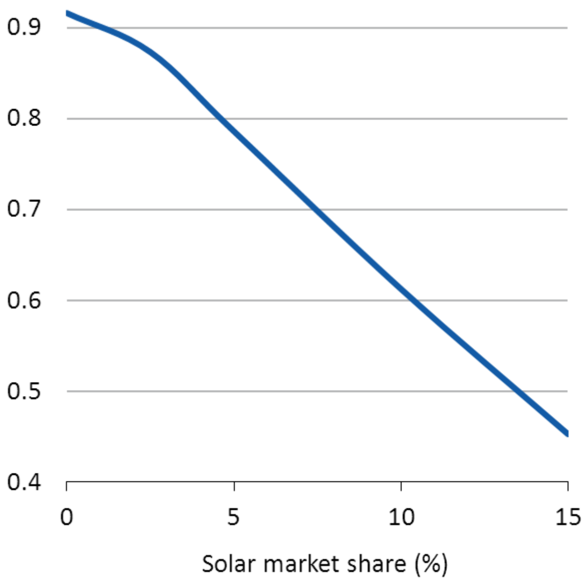

Figure 14. Mid-term solar value factor drops below 0.5 at only 15% penetration rate.

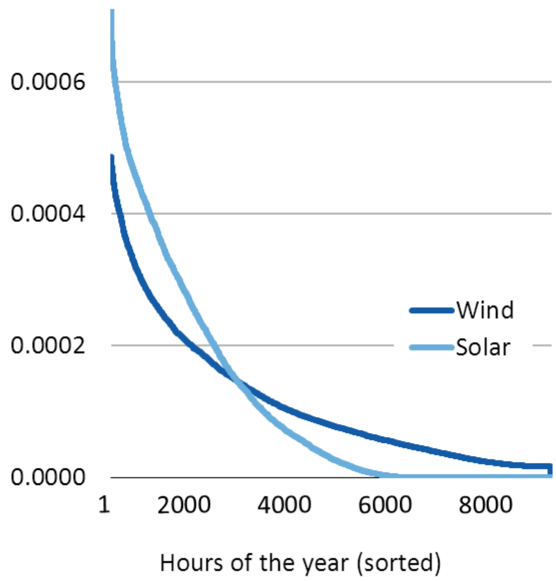

Figure 15. Generation duration curves for solar and wind power. Solar generation is concentrated in fewer hours than wind generation.

5.3 Renewables Mix

If both wind and solar power are introduced simultaneously, the respective value shares drops less when calculated as a function of renewables capacity (Figure 16). However, the drop is still considerable. This indicates that notwithstanding wind speeds and solar radiation being negatively correlated, an energy system with large shares of both VRE technologies leads to low value factors for both technologies.

[13] If we assume that full costs are today 250 €/MWh on European average, the global learning rate is 10%, and that global capacity doubles four times as fast as European capacity, we will have full costs of around 100 €/MWh at 15% market share.

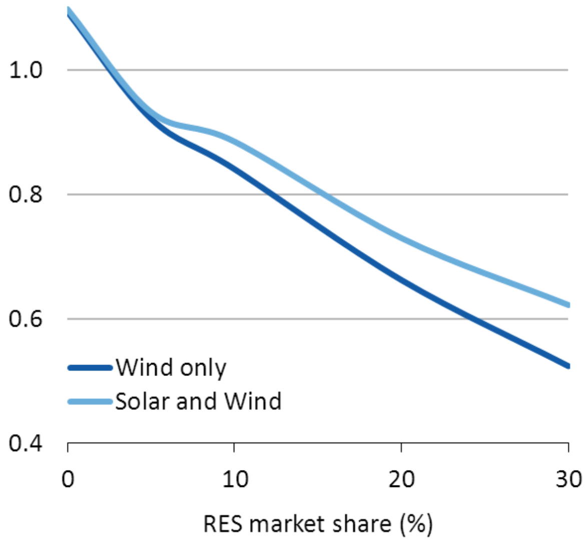

Figure 16: Wind value factor with and without solar.

5.4 Long-term market value

This subsection applies a long-term framework, without any previously existing conventional power plants. In comparison to the mid-term, the power system can adjust more flexibly to a given amount of VRE.

Higher shares of VRE reduce the amount of energy generated by thermal power plants, without reducing total thermal capacity much (Hirth 2012a). This reduces the average utilization of thermal plants, which increases specific capital costs. Nicolosi (2012) termed this the “utilization effect”. In a long-term framework this effects exists, but is weaker than in the mid-term, because the system is not locked in with too high amounts of base load technologies. Thus, the long-term market value of VRE is usually higher than its mid-term value (Figure 17).

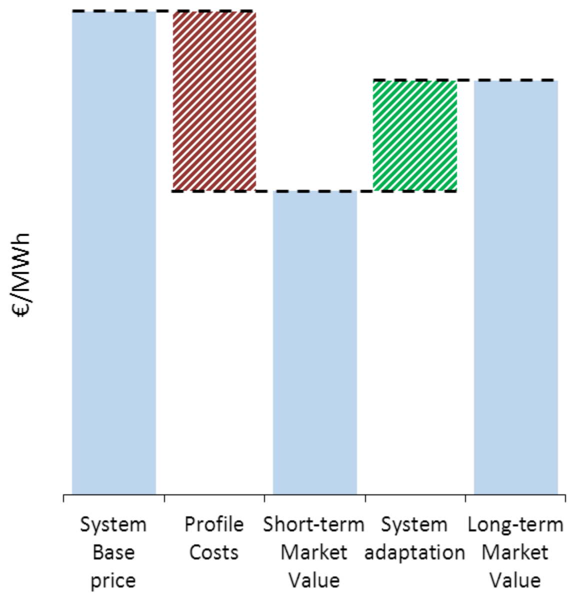

Figure 17. System adaptation causes the long-term market value to be higher than the short-term value. The major factor is a shift of the generation mix from base load towards mid and peak load.

In the EMMA simulations, the average utilization of dispatchable capacity decreases from about 54% to 39% as the wind penetration rate is increased to 30%. The long-term wind value factor is 0.65 at 30% market share, almost 15 percentage points higher than the mid-term factor. At penetration rates below 10%, wind power does not alter the optimal capacity mix significantly, thus mid-term and long-term value factors are identical (Figure 18).

The base price is also more stable in the long run than in the medium run (Figure 19). As formally shown by Lamont (2008), the long-term base price is set by the LCOE of the cheapest base load technology as long as there is one technology that runs base load. At high penetration, the absolute long-term wind value is about twice as high as the mid-term value.

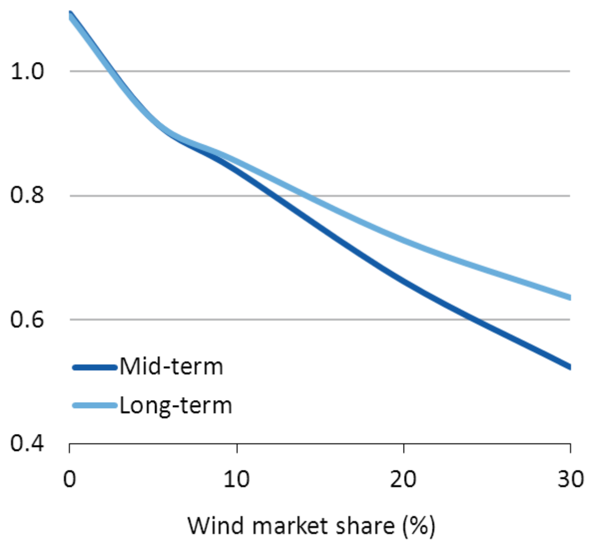

Figure 18. At high penetration rates, The long-term value factor is significantly higher than the mid-term value factor.

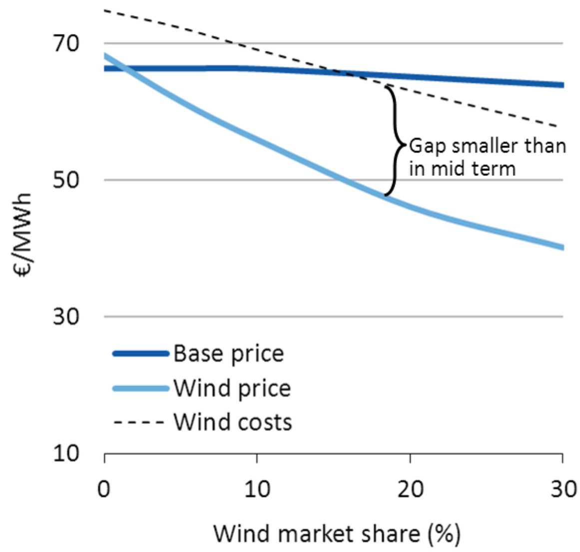

Figure 19. The long-term wind market value in absolute terms. While the value is twice as high as the mid-term value at high penetration rates, it is still significantly below full

costs.

The capacity mix has a higher share of peak load capacity in the long-term equilibrium (Figure 20). The difference between market values is larger in countries with a high base load capacity such as France. However, it is important to note that also the long-run market value drops significantly with increasing market shares.

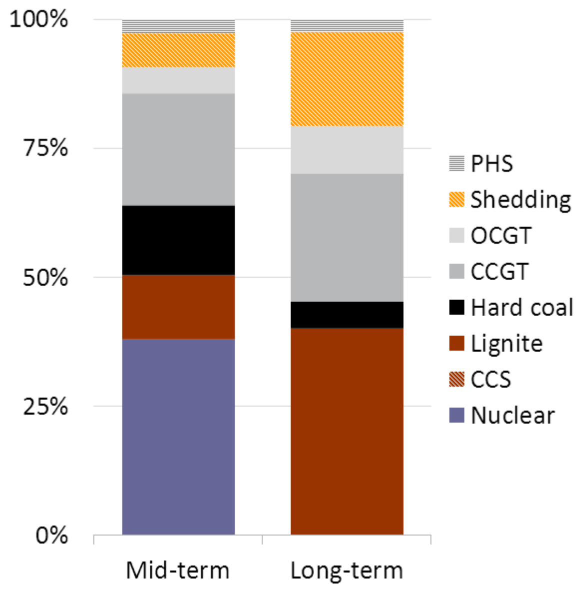

Figure 20. Capacity mix at 30% wind power. The long-term equilibrium capacity mix has larger shares of mid- and peak load technologies.

In the remainder of section 5, the effects of changing price assumptions and policies on the market value of wind and solar will be tested. Specifically, CO_2 prices, fuel prices, interconnector and storage capacity, and the flexibility of conventional generators will be varied. There are two reasons for doing this: on the one hand we want to understand the range of outcomes due to parameter uncertainty. On the other hand, we use the findings to identify promising integration options that help mitigating the value drop of VRE. The run with unchanged parameters is used as a point of reference or "benchmark".

5.5 CO2 pricing

Carbon pricing is one of the most important policies in the power sector, and many observers suggest that CO_2 pricing has a significantly positive impact on VRE competitiveness: a higher carbon price increases the variable costs of emitting plants, and hence increases the average electricity price. However, there are two other channels through which carbon pricing affects the value of VRE. A higher price makes the merit order curve flatter in the range of lignite – hard coal – CCGT, increasing the value factor at high penetration. Finally, a higher CO_2 price induces investments in low-carbon technologies. The available dispatchable low-carbon technologies in EMMA are nuclear power and lignite CCS, both featuring very low variable costs. Thus, these new investments make the merit-order curve steeper. In contrast, a lower CO_2 price reduces the electricity prices, makes the merit-order curve of emitting plants steeper, and induces investments in lignite, further increasing the slope of the merit-order curve. Thus the overall effect of a higher carbon price on the market value of VRE is ambiguous a priori, but a lower carbon price should strictly reduce VRE value.

To quantify these arguments, the benchmark CO_2 price of 20 €/t was changed to zero and 100 €/t. Because mid-term and long-term effects are quite similar, only long-term results are shown. The central finding of this sensitivity is that *both* higher and lower CO_2 prices reduce the absolute market value of wind power (Figure 21). At a CO_2 price of 100 €/t, about half of all dispatchable capacity is nuclear power, such that the merit-order effect is so strong that even absolute revenues of wind generators are reduced – despite a significant increase in electricity prices. This might be one of the more surprising results of this study: tighter carbon prices might actually reduce the income of VRE generators, if the adjustment of the capital stock is taken into account.

This finding heavily depends on new investments in nuclear or CCS. If those technologies are not available for new investments – for example due to security concerns or lack of acceptance – the market value of wind is dramatically higher (Figure 22). The base price increases, and the merit-order becomes so flat that the price seldom drops below the variable costs of hard coal. Indeed, even at current wind cost levels, more than 30% of wind power would be competitive. However, excluding nuclear power and CCS results in a dramatic increase of carbon emissions: while a CO_2 price of 100 €/t brings down emissions from 900 Mt to 200 Mt per year, emissions increase to more than 500 Mt if nuclear and CCS are unavailable, even at 30% wind. Hence, excluding nuclear and CCS from the set of available technologies will help wind power to become competitive, but it also leads to dramatically higher CO_2 emissions.

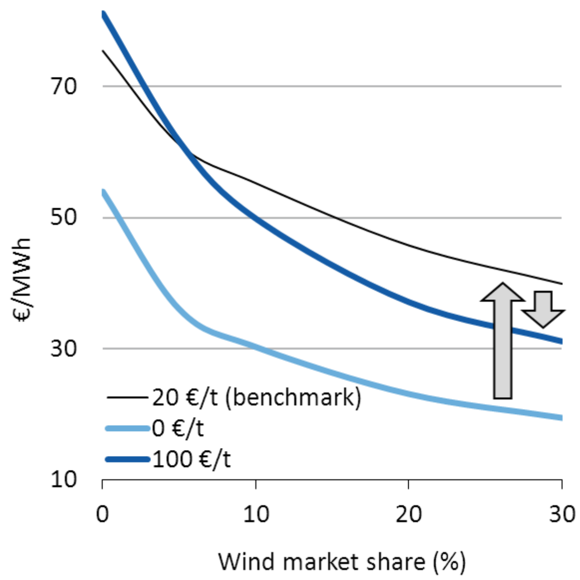

Figure 21. Absolute long-term wind value at different CO_2 prices. At penetration rates above five percent, a CO_2 price of 100 €/t results in *lower* income for wind generators than 20 €/t. The arrows indicate the change in income as the CO_2 rises.

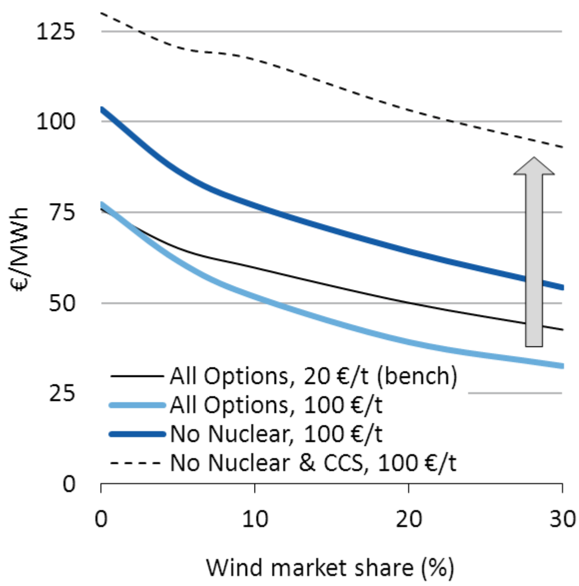

Figure 22. Absolute long-term wind value at 100 €/CO_2 prices for different technology assumptions. The arrow indicates the effect of excluding nuclear and CCS at 100 €/t CO_2.

5.6 Fuel prices

For the benchmark run, 2011 market prices are used for the globally traded commodities hard coal (12 €/MWh_t) and natural gas (24 €/MWh_t). It is sometimes argued that higher fuel prices, driven by depleting resources, will make renewables competitive. In this section, gas and coal prices were doubled separately and simultaneously. A plausible expectation is that higher fuel costs, driving up the electricity price, increase the value of wind power.

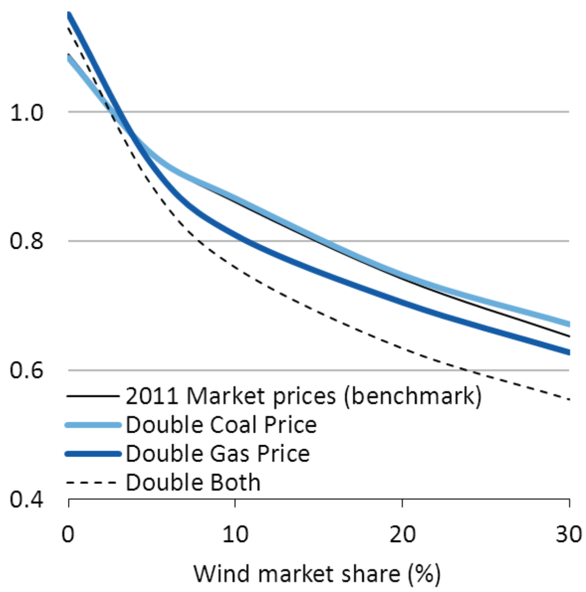

Figure 23. Long-term wind value factors at various fuel prices. The base price is virtually identical in all four runs.

However, results do not confirm this hypothesis. Again, fuel price changes affect the value of RES through different channels. A change in relative input prices induces substitution of fuels, such that the average electricity price remains virtually unchanged. In contrast, the merit-order curve changes significantly. With a higher coal price, it becomes flatter. With a higher gas price, it becomes steeper. If both prices double, new lignite and nuclear investment lead to it becoming much steeper.

As a result, higher gas prices reduce the wind value factor (Figure 23) and reduce the absolute value of wind. These results indicate that it is not necessarily the case that VRE benefit from higher fuel prices; indeed they might even lose. Mid-term results are similar and not shown.

The seemingly counter-intuitive effects of CO_2 and fuel prices on the value of wind indicate how important it is to take adjustments of the capital stock into account when doing policy analysis.

5.7 Interconnector capacity

Higher long-distance transmission capacity helps to balance fluctuations of VRE generation. In the benchmark runs, it was assumed that interconnectors have today's capacities. To understand the effect of transmission expansion on VRE market value, NTC constraints were first set to zero to completely separate markets, they were then doubled from current levels, and finally taken out to fully integrate markets throughout the region.

The impact of transmission expansion is dramatically different in a long-term and a mid-term framework. Long-term results indicate that long-distance transmission expansion supports the market value of wind in all countries (Figure 24). However, the size of the effect is small: doubling the capacity of all existing interconnectors merely leads to an increase of wind's value factor by one percentage point at high penetration levels.

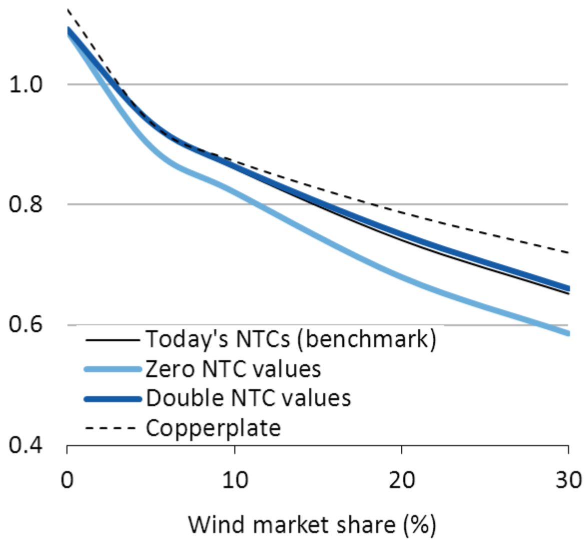

Figure 24. Long-term wind value factors in the model region at different NTC assumptions. The impact of doubling NTC capacity is moderate in size, but positive in all countries.

Mid-term results show how existing thermal capacity interacts with shocks to the system and how dramatically this can alter outcomes. While more interconnector capacity reduces the mid-term value of wind in Germany, it increases it dramatically in France (Figure 25, Figure 26). This result is explained by the large existing French nuclear fleet: in France, prices are often set by nuclear power during windy hours at high wind penetration rates. Since French and German winds are highly correlated, during windy hours French nuclear power becomes the price setter in Germany. With more interconnector capacity, this effect is more pronounced. Thus long-distance transmission prevents French wind power from being locked in with low nuclear prices, but hits German wind power by importing French nuclear power during windy times.

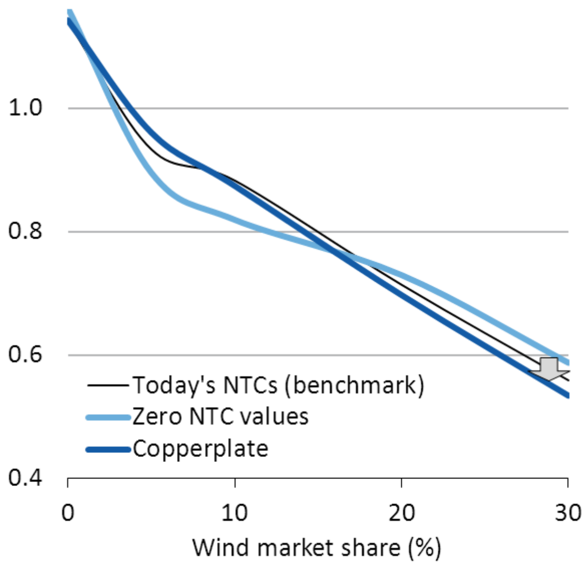

Figure 25. The German mid-term wind value factor is reduced if interconnector capacity is increased (arrow).

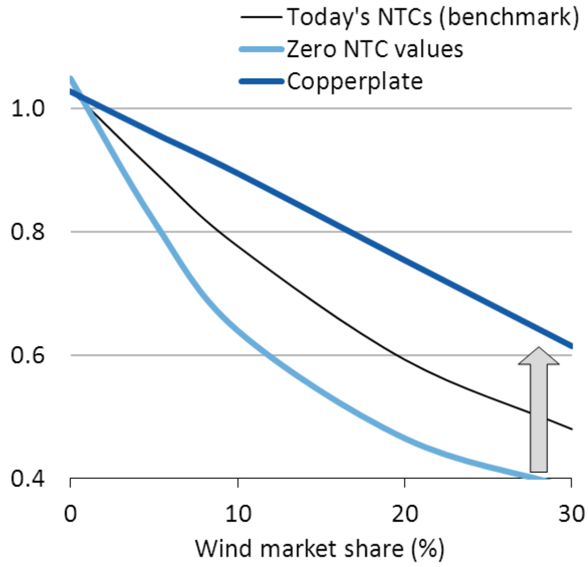

Figure 26. The French mid-term wind value increases strongly with more interconnector capacity (arrow).

These findings are consistent with previous studies. Obersteiner (2012) models the impact of interconnectors on VRE market value and reports a positive impact if generation profiles are less then perfectly correlated and supply conditions similar. This is indeed the case in the long run, but not when taking the existing French nuclear capacities into account. While Nicolosi (2012) finds a strong and positive effect of grid extension on the mid-term market value of German wind power, his finding is driven by the assumption that Germany will continue its role as a "renewable island," with much higher wind shares than its neighboring countries. If this is the case, German wind power benefits from exporting electricity during wind times. In contrast, we assume penetration to be identical in all markets.

5.8 Storage

Electricity storage is widely discussed as a mean of VRE integration and as a prerequisite for system transformation. Here the influence of storage on the value of VRE is tested by setting pumped hydro storage capacity to zero and doubling it from current levels.

The effect on wind is very limited: at 30% penetration, the difference in value factors between zero and double storage capacity is only one percentage point in the mid-term and five points in the long term. The driver behind this outcome is the design of pumped hydro plants. They are usually designed to fill the reservoir in six to eight hours while wind fluctuations occur mainly on longer time scales (Hirth & Müller 2013). Thus, wind requires a storage technology that has a large energy-to-power ratio than pumped hydro storage.

For solar, the situation is different. Due to its pronounced diurnal fluctuations, solar power benefits much more from additional pumped hydro storage: at 15% solar market share, its mid-term value factor is five percentage points higher with double storage capacity than without storage. The long-term value is nine percentage points higher. At low penetration levels, however, storage actually *reduces* the value of solar power by shaving the noon peak.

Both wind and solar power could potentially benefit from hydro reservoir power. Hydro power plants in Norway, Sweden, and the Alps often have large hydro reservoirs. They are able to provide flexibility, even though they usually lack the capability of pumping. As mentioned in section 4, reservoirs are not modeled in EMMA.

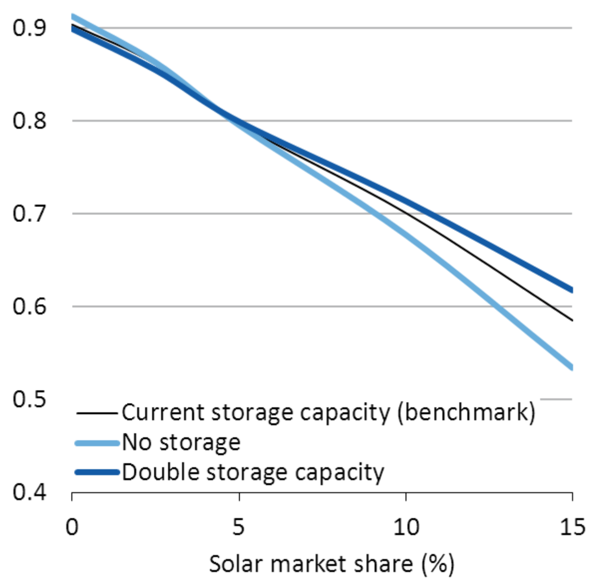

Figure 27: Long-term solar value factor at different storage assumptions.

5.9 Flexible conventional generators

There are many technical constraints at the plant and the power system level that limit the flexibility of dispatchable plants. If they are binding, all these constraints tend to reduce the value of variable renewables at high market shares. Three types of inflexibilities are modeled in EMMA: a heat-supply constraint for CHP plants, a must-run constraint for suppliers of ancillary services, and a run-through premium that proxies start-up and ramping costs of thermal plants (section 4).

There are technologies that can be used to relax each of these constraints: CHP plants can be supplemented with heat storages or electrical boilers to be dispatched more flexibly. Batteries, consumer appliances, or power electronics could help to supply ancillary services. Both measures imply that thermal plants can be turned down more easily in times of high VRE supply. In general, new plant designs and retrofit investments allow steeper ramps and quicker start-ups.

To test for the potential impact of such measures, each constraint is disabled individually and jointly. Disregarding the constraints altogether is, of course, a drastic assumption, but gives an indication of the potential importance of increasing the system flexibility.

The mid-term value factors indicate that the impact of adding flexibility to the system is large (Figure 28). As expected, adding flexibility increases the market value of wind. What might be surprising is the size of the effect: making CHP plants flexible alone increases the value factor by more than ten percentage points at high penetration levels. All flexibility measures together increase the market value of wind by an impressive 40%. At high wind penetration, the amount of hours where prices drop below the variable costs of hard coal is reduced from more than 50% to around 20% (Figure 29).

While one needs to keep in mind that in this modeling setup complex technical constraints are implemented as simple linear parameterizations, these results indicate that increasing system and plant flexibility is a promising mitigation strategy to stem the drop in VRE market value. Furthermore, flexibility can provide additional benefits by reducing balancing costs – thus, the importance of flexibility for the market value of wind is probably underestimated.

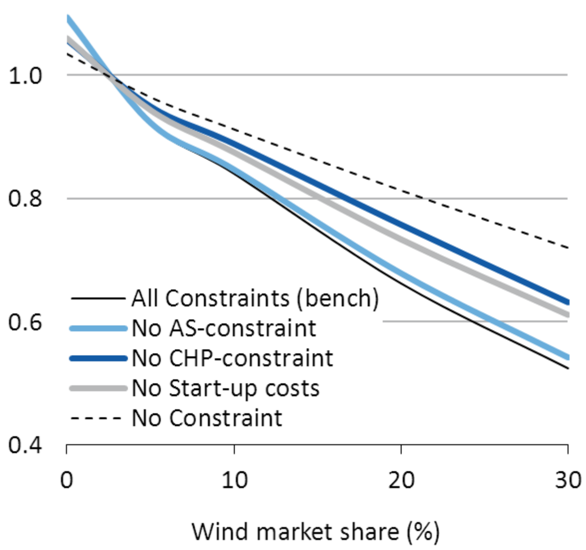

Figure 28: Mid-term market value for wind with additional flexibility measures.

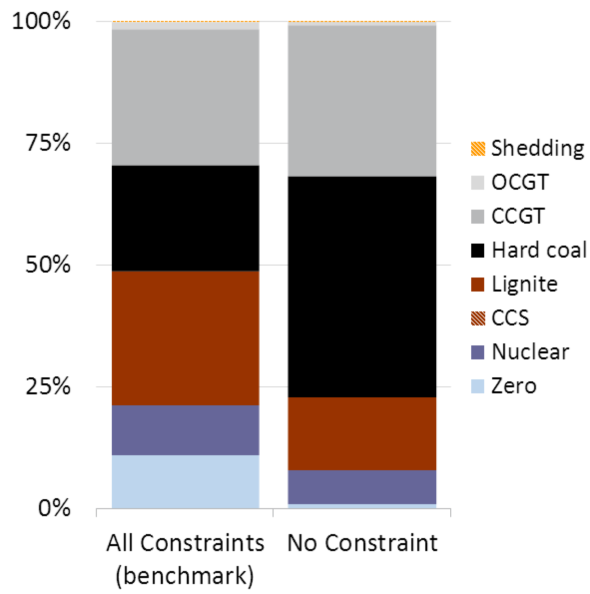

Figure 29: Price setting fuel at 30% wind share with and without inflexibilities in Germany.

6. Discussion

All model results should be interpreted keeping methodological shortcomings in kind. Hydro reservoirs, demand elasticity, and technological innovations are not modeled, which probably is a downward bias to VRE market values. Internal grid bottlenecks and VRE forecast errors are not accounted for, which might bias the value upwards. Also historical market data should be interpreted carefully, keeping historical conditions in mind. The relatively low market share and the fact that Germany and Denmark are surrounded by countries with much lower penetration rates raise doubts if findings can be projected to the future. These considerations in principle also apply to the literature reviewed.

The first and foremost result of this study is that the market value of both wind and solar power is significantly reduced by increasing market shares of the respective technology. At low penetration levels, the market value of both technologies is comparable to a constant source of electricity, or even higher. At 30% market share, the value of wind power is reduced to 0.5 – 0.8 of a constant source. Solar reaches a similar reduction already at 15% penetration.

Secondly, it is important to note that the size of the drop depends crucially on the time frame of the analysis. If previously-existing capacity is taken into account (mid-term framework), value factor estimates are usually lower than if it is not (long-term), especially at higher penetration rates. This holds for the reviewed literature as well as EMMA model results. Model results indicate that at high penetration rates, the absolute long-term market value is about twice the mid-term value.

Finally, prices and policies strongly affect the market value of VRE. Table 8 summarizes the effects of the price and policy shocks on wind value factors as estimated in section 5. Some results are as expected, such as the negative effect of low CO_2 prices on the value of wind, the positive effect of high coal prices on the wind value, or the long-term benefits of market integration. A number of results, however, might come as a surprise. For example, a higher CO_2 price reduces the value of wind by inducing nuclear investments, a higher natural gas prices has a similar effect by inducing coal investments, and interconnection expansion reduce the value of German wind because of cheap imports from France. Typically, the reason is that shocks trigger new investments or interact with existing conventional capacity, which can qualitatively alter the impact on VRE market value. As a consequence, there are three channels through which changes in the energy system affect the value of VRE, of which the obvious – the impact on the price level – is often not the most important one (Figure 30).

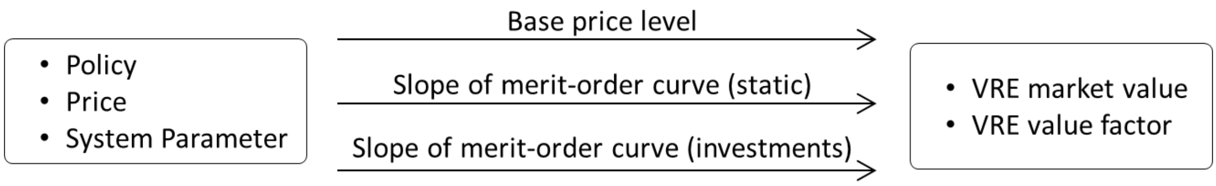

Figure 30: Policies, price shocks, and a change of power system parameters affect the absolute and relative value of VRE through three channels: changes of the electricity price level, changes of the slope of the merit-order curve via variable cost changes, and changes of the merit-order curve via changes in the capacity mix.

Table 8: Divers of wind value factors

Change	**Value factor**	**Dominating Chains of Causality**

CO_2 price ↓	↓	Steeper merit-order curve due to lower variable costs of coal
CO_2 price ↑	↓	Steeper merit-order curve due to investment in nuclear and CCS
CO_2 price ↑ nuc/CCS ↓	↑↑	Flatter merit-order curve due to higher variable costs of coal; Overall price increase
Coal price ↑	↑	Flatter merit-order curve in the range hard coal – gas; Lignite investments partly compensate
Gas price ↑	↓	Steeper merit-order curve due to higher variable costs of gas; Lignite and hard coal investments reinforce this effect
Interconnectors ↑	↑ (LT) ↑/↓ (MT)	Long term: smoothening out of wind generation across space; Mid term: German wind suffers from low prices set by French nuclear
Storage ↑	–	Small impact of wind because of small reservoirs; Negative impact on solar at low penetration rates, positive at high rates
Plant Flexibility ↑	↑↑	Reduced must-run generation leads to higher prices especially during hours of high wind supply

Figure 31 and Figure 32 summarize all mid-term and long-term model runs for wind power, including those that were not discussed in detail in section 5. The resulting family of value factor curves can be interpreted as the range of value factors introduced by uncertainty about energy system parameters (Figure 33). The model suggests that the mid-term wind value factor is in the range of 0.4 – 0.7 at 30% market share, with a benchmark point estimate of slightly above 0.5. The long-term value is estimated to be between 0.5 – 0.8, with a point estimate of 0.65. Historical observations and the regression line from section 3.3 lie within the range of model results.

The estimations of wind value factors are consistent with most of the previous studies that model investments endogenously (Lamont 2008, Nicolosi 2012, Mills & Wiser 2012), but somewhat lower than Swider & Weber (2006). Also, other findings are consistent with the existing literature, such as the wind value factor being above unity at low penetration levels (Sensfuß 2007, Obersteiner & Saguan 2010, Energy Brainpool 2011) and the solar value factor dropping more rapidly than wind with growing market shares (Lamont 2008, Gowrisankaran et al. 2011, Mills & Wiser 2012, Nicolosi 2012).

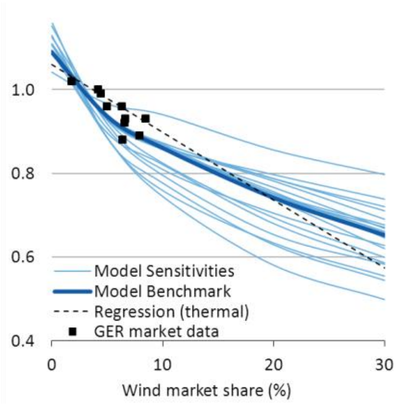

Figure 31. All long-term wind value factors. The lowest value factors are estimated at 100 €/t CO_2 pricing and the highest at 100 €/t CO_2 if nuclear and CCS are unavailable.

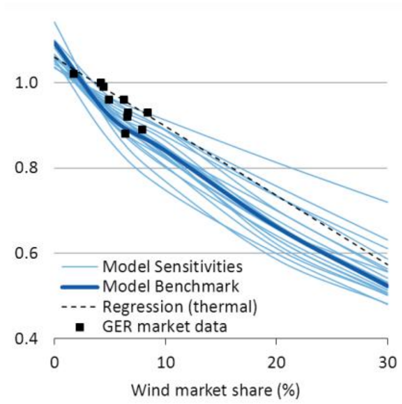

Figure 32. All mid-term wind value factors.

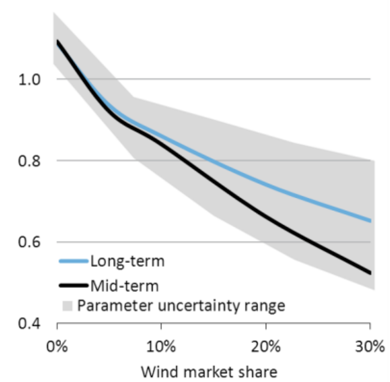

Figure 33. Parameter uncertainty. The shaded area indicates the upper and lower extremes of mid- and long-term runs.

The model results do *not* imply that a different "market design" is needed to prevent the value drop of VRE. In contrast, the reduction in value is not a market failure but a direct consequence of the inherent properties of VRE. Why we use the term “market value”, more precisely it is the marginal economic value that is calculated in EMMA – which is independent from the design of markets.

7. Conclusions

Electricity systems with limited intertemporal flexibility provide a frosty environment for variable renewables like wind and solar power. If significant VRE capacity is installed, the merit-order effect depresses the electricity price whenever these generators produce electricity. This implies that the per MWh value of VRE decreases as more capacity is installed.

A review of the published literature, regression analysis of market data, and a numerical model of the European power market were used in this study to quantify this drop and identify drivers. We find that the value of wind power is slightly higher than the value of a constant electricity source at low penetration; but falls to 0.5-0.8 at a market share of 30%. Solar reaches a similar level at 15% penetration, because its generation is concentrated in fewer hours. We identify several drivers that affect the value of renewables significantly.

These findings lead to a number of conclusions. Firstly, there are a number of integration options that help mitigating the value drop of VRE: transmission investments, relaxed constraints on thermal generators, and a change in wind turbine design could be important measures. Especially increasing CHP flexibility seems to be highly effective. Increasing wind turbine rotor diameters and hub heights reduce output variability and could help to stabilize wind’s market value. Secondly, variable renewables need mid and peak load generators as complementary technologies. Biomass as well as highly efficient natural gas-fired plants could play a crucial role to fill this gap. On the other hands, low-carbon base load technologies such as nuclear power or CCS do not go well with high shares of VRE. Thirdly, we find that a high carbon price alone does not make wind and solar power competitive at high penetration rates. In Europe that could mean that even if CO_2 prices pick up again, subsidies would be needed well beyond 2020 to reach ambitious renewables targets. Finally, without fundamental technological breakthroughs, wind and solar power will struggle becoming competitive on large scale, even with quite steep learning curves. Researchers as well as policy makers should take the possibility of a limited role for solar and wind power into account and should not disregard other greenhouse gas mitigation options too early.

In terms of methodology, we conclude that any model-based evaluation of the value of VRE needs to feature high temporal resolution, account for operational constraints of power systems, cover a large geographic area, take into account existing infrastructure, and model investments endogenously.

The work presented here could be extended in several directions. A more thorough evaluation of specific flexibility options is warranted, including a richer set of storage technologies, demand side management, long-distance interconnections, and heat storage. A special focus should be paid to the existing hydro reservoirs in Scandinavia, France, Spain and the Alps. While this study focuses on profile costs, there are two other components that determine the market value of VRE: balancing and grid-related costs. Further research on those is needed before final conclusions regarding the market value of variable renewables can be drawn.

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Appendix A: Generalized vector notation

The matrix nomenclature introduced in section 3 can be easily generalized to account for spatial price and wind variability and grid-related costs (recall the framework introduced in section 1).

The vector $\mathbf{p}_{[T\times 1]}$ becomes a matrix of prices $\mathbf{P}_{[T\times N]}$ and the vector $\mathbf{g}_{[T\times 1]}$ a matrix of generation factors $\mathbf{G}_{[T\times N]}$. A new vector $\mathbf{d}_{[N\times 1]}$ is introduced that contains the spatial weights of demand where N is the number of price zones. Equation (1) becomes (A.1) and (2) becomes (A.2). Equation (3) remains unchanged.

$$\bar{p} = \left[(\mathbf{Pd})'\mathbf{t}\right] / \left[(\mathbf{1}'\mathbf{t})(\mathbf{1}'\mathbf{n})\right] \tag{A.1}$$

$$\bar{p}^{w} = \left[((\mathbf{P}'\mathbf{G})\mathbf{n})'\mathbf{n}\right] / \left[(\mathbf{Gn})'\mathbf{t}\right] \tag{A.2}$$

Appendix B: Numerical Model

B.1 Total System Costs

The model minimizes total system costs C with respect to a large number of decision variables and technical constraints. Total system costs are the sum of fixed generation costs $C_{r,i}^{fix}$, variable generation costs $C_{t,r,i}^{var}$, and capital costs of storage C_r^{sto} and transmission $C_{r,rr}^{trans}$ over all time steps t, regions r, and generation technologies i:

$$\begin{aligned} C &= \sum_{r,i} C_{r,i}^{fix} + \sum_{r,i,t} C_{t,r,i}^{var} + \sum_{r} C_r^{sto} + \sum_{r,rr} C_{r,rr}^{trans} \\ &= \sum_{r,i} \left(\hat{g}_{r,i}^{inv} \cdot \left(c_i^{inv} + c_i^{qfix} \right) + \hat{g}_{r,i}^{0} \cdot c_i^{qfix} \right) + \sum_{t,r,i} g_{t,r,i} \cdot c_i^{\mathrm{var}} + \sum_{r} \hat{s}_r^{inv} \cdot c^{sto} + \sum_{r,rr} \hat{x}_{r,rr}^{inv} \cdot \phi_{r,rr} \cdot c^{NTC} \end{aligned} \tag{B.1}$$

where $\hat{g}_{r,i}^{inv}$ is the investments in generation capacity and $\hat{g}_{r,i}^{0}$ are existing capacities, c_i^{inv} are annualized specific capital costs and c_i^{qfix} are yearly quasi-fixed costs such as fixed operation and maintenance (O&M) costs. Variable costs are the product of hourly generation $g_{t,r,i}$ with specific variable costs c_i^{var} that include fuel, CO_2, and variable O&M costs. Investment in pumped hydro storage capacity $\hat{s}_r^{io,inv}$ comes at an annualized capital cost of c^{sto} but without variable costs. Transmission costs are a function of additional interconnector capacity $\hat{x}_{r,rr}^{inv}$, distance between markets $\phi_{r,rr}$, specific annualized NTC investment costs per MW and km c^{NTC}.

Upper-case C's denote absolute cost while lower-case c's represent specific (per-unit) cost. Hats indicate capacities that constrain the respective flow variables. Roman letters denote variables and Greek letters denote parameters. The two exceptions from this rule are initial capacities such as $\hat{g}_{r,i}^{0}$ that are denoted with the respective variable and zeros in superscripts, and specific costs c.

There are eleven technologies, five regions, and 8760 times steps modeled. Note that (1) does not contain a formulation for distribution grids, which contribute a significant share of household electricity cost.

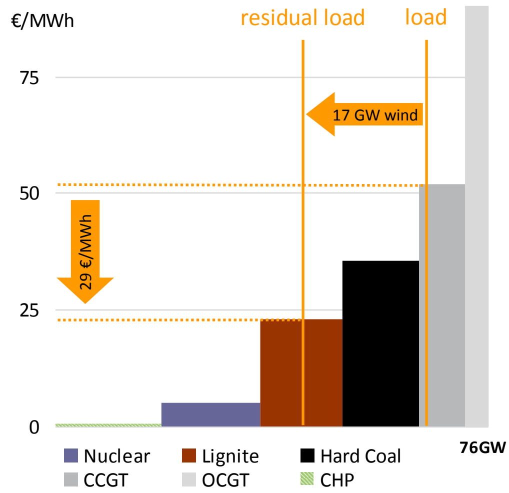

Figure 34. …

B.2 Supply and Demand

The energy balance (2) is the central constraint of the model. Demand $\delta_{t,r}$ has to be met by supply during every hour and in each region. Supply is the sum of generation $g_{t,r,i}$ minus the sum of net exports $x_{t,r,rr}$ plus storage output $s^o_{t,r}$ minus storage in-feed $s^i_{t,r}$. Storage cycle efficiency is given by η. The hourly electricity price $p_{t,r}$ is defined as the shadow price of demand and has the unit €/MWh. The base price $\bar{p}_r$ is the time-weighted average price over all periods T. Note that (2) features an inequality, implying that supply can always be curtailed, thus the price does not become negative. The model can be interpreted as representing an energy-only market without capacity payments, and $p_{t,r}$ can be understood as the market-clearing zonal spot price as being implemented in many deregulated wholesale electricity pool markets. Since demand is perfectly price-inelastic, cost minimization is equivalent to welfare-maximization, and $p_{t,r}$ can also be interpreted as the marginal social benefit of electricity.

$$\delta_{t,r} \leq \sum_i g_{t,r,i} - \sum_{rr} x_{t,r,rr} + \eta \cdot s^o_{t,r} - s^i_{t,r} \qquad \forall t,r \qquad \text{(B.2)}$$

$$p_{t,r} \equiv \frac{\partial C}{\partial \delta_{t,r}} \qquad \forall t,r$$

$$\bar{p}_r \equiv \sum_t p_{t,r} \Big/ T \qquad \forall r$$

Generation is constraint by available installed capacity. Equation (3) states the capacity constraint for the VRE technologies $j \in i$, wind and solar power. Equation (4) is the constraint for dispatchable generators $m \in i$, which are nuclear, lignite, hard coal, CCGT, and OCGT as well as load shedding. Note that technology aggregates are modeled, not individual blocks or plants. Renewable generation is constraint by exogenous generation profiles $\varphi_{t,r,j}$ that captures both the variability of the underlying primary energy source as well as technical non-availability. Availability $\alpha_{t,r,k}$ is the technical availability of dispatchable technologies due to maintenance. Dispatchable capacity can be decommissioned endogenously via $\hat{g}_{r,k}^{dec}$ to save on quasi-fixed costs, while VRE capacity cannot. Both generation and capacities are continuous variables. The value factors $v_{r,j}$ are defined as the average revenue of wind and solar relative to the base price.

$$g_{t,r,j} = \hat{g}_{r,j} \cdot \varphi_{t,r,j} = \left(\hat{g}_{r,j}^{0} + \hat{g}_{r,j}^{inv}\right)\varphi_{t,r,j} \qquad \forall t, r, j \in i \qquad \text{(B.3)}$$

$$g_{t,r,k} \leq \hat{g}_{r,k} \cdot \alpha_{t,r,k} = \left(\hat{g}_{r,k}^{0} + \hat{g}_{r,k}^{inv} - \hat{g}_{r,k}^{dec}\right)\alpha_{t,r,k} \qquad \forall t, r, m \in i \qquad \text{(B.4)}$$

$$v_{r,j} \equiv \sum_t \varphi_{t,r,j} p_{t,r} \Big/ \sum_t \varphi_{t,r,j} \Big/ \overline{p}_r \qquad \forall r, j \in i$$

Minimizing (1) under the constraint (3) implies that technologies generate if and only if the electricity price is equal or higher than their variable costs. It also implies the electricity price equals variable costs of a plant if the plant is generating and the capacity constraint is not binding. Finally, this formulation implies that if all capacities are endogenous, all technologies earn zero profits, which is the long-term economic equilibrium (for an analytical proof see Hirth & Ueckerdt 2012).

B.3 Power System Inflexibilities

One of the aims of this model formulation is, while remaining parsimonious in notation, to include crucial constraint and inflexibilities of the power system, especially those that force generators to produce at prices below their variable costs (must-run constraints). Three types of such constraints are taken into account: CHP generation where heat demand limits flexibility, a must-run requirement for providers of ancillary services, and costs related to ramping, start-up and shut-down of plants.

One of the major inflexibilities in European power systems is combined heat and power (CHP) generation, where heat and electricity is produced in one integrated process. High demand for heat forces plants to stay online and generate electricity, even if the electricity price is below variable costs. The CHP must-run constraint (5) guarantees that generation of each CHP technology $h \in m$, which are the five coal- or gas-fired technologies, does not drop below minimum generation $g_{t,r,h}^{min}$. Minimum generation is a function of the amount of CHP capacity of each technology $k_{r,h}$ and the heat profile $\varphi_{t,r,chp}$. The profile is based on ambient temperature and captures the distribution of heat demand over time. CHP capacity of a technology has to be equal or smaller than total capacity of that technology (6). Furthermore, the current total amount of CHP capacity in each region γ_r is not allowed to decrease (7). Investments in CHP capacity $k_{r,h}^{inv}$ as well as decommissioning of CHP $k_{r,h}^{dec}$ are possible (8), but only to the extent that total power plant investments and disinvestments take place (9), (10). Taken together, (6) – (10) allow fuel switch in the CHP sector, but do not allow reducing total CHP capacity. For both the generation constraint (5) and the capacity constraint (7) one can derive shadow prices $p_{t,r,h}^{CHPgene}$ (€/MWh) and $p_r^{CHPcapa}$ (€/KWa), which can be interpreted as the opportunity costs for heating energy and capacity, respectively.

$$g_{t,r,h} \geq g_{t,r,h}^{min} = k_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,h} \qquad \forall t,r,h \in m \qquad \text{(B.5)}$$

$$k_{r,h} \leq \hat{g}_{r,h} \qquad \forall r,h \qquad \text{(B.6)}$$

$$\sum_h k_{r,h} \geq \gamma_r = \sum_h k_{r,h}^0 \qquad \forall r \qquad \text{(B.7)}$$

$$k_{r,h} = k_{r,h}^0 + k_{r,h}^{inv} - k_{r,h}^{dec} \qquad \forall r,h \qquad \text{(B.8)}$$

$$k_{r,h}^{inv} \leq \hat{g}_{r,h}^{inv} \qquad \forall r,h \qquad \text{(B.9)}$$

$$k_{r,h}^{dec} \leq \hat{g}_{r,h}^{dec} \qquad \forall r,h \qquad \text{(B.10)}$$

$$p_{r,t}^{CHPgene} \equiv \frac{\partial C}{\partial g_{t,r,h}^{min}} \qquad \forall r,t$$

$$p_r^{CHPcapa} \equiv \frac{\partial C}{\partial \gamma_r} \qquad \forall r$$

Electricity systems require a range of measures to ensure stable and secure operations. These measures are called ancillary services. Many ancillary services can only be or are typically supplied by generators while producing electricity, such as the provision of regulating power or reactive power (voltage support). Thus, a supplier that committed to provide such services over a certain time (typically much longer than the delivery periods on the spot market) has to produce electricity even if the spot prices falls below its variable costs. In this model, ancillary service provision is implemented as a must-run constraint (11): An amount σ_r of dispatchable capacity has to be in operation at any time. While in reality, σ_r is a function of the current status of the power system and thus variable, for the present model σ_r is set to 20% of the annual peak demand of each region. Two pieces of information were used when setting this parameter. First, market prices indicate when must-run constraints become binding: if equilibrium prices drop below the variable cost of base load plants for extended periods of time, must-run constraints are apparently binding. Nicolosi (2012) reports that German power prices fell below zero at residual loads between 20-30 GW, about 25-40% of peak load. Second, FGH et al. (2012) provide a detailed study on must-run generation due to system stability, taking into account network security, short circuit power, voltage support, ramping, and regulating power. They find minimum generation up to 25 GW in Germany, about 32% of peak load.

In EMMA it is assumed that CHP generators cannot provide ancillary services, but pumped hydro storage can provide them while either pumping or generating. For a region with a peak demand of 80 GW, at any moment 16 GW of dispatchable generators or storage have to be online. Note that thermal capacity of 8 GW together with a pump capacity of 8 GW can fulfill this condition without net generation. The shadow price of σ_r, $p_{t,r}^{AS}$,is defined as the price of ancillary services, with the unit €/KW_{online}a.

$$\sum_k g_{t,r,k} - \sum_h \kappa_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,h} + \eta \cdot s_{t,r}^o + s_{t,r}^i \geq \sigma_r = 0.2 \cdot \max_t \left(\,?_{t,r} \right) \qquad \forall t,r \qquad \text{(B.11)}$$

$$p_r^{AS} \equiv \frac{\partial C}{\partial \sigma_r} \qquad \forall r$$

Finally, thermal power plants have limits to their operational flexibility, even if they do not produce goods other than electricity. Restrictions on temperature gradients within boilers, turbines, and fuel gas treatment facilities and laws of thermodynamics imply that increasing or decreasing output (ramping), running at partial load, and shutting down or starting up plants are costly or constraint. In the case of nuclear power plants nuclear reactions related to Xenon-135 set further limits on ramping and down time. These various non-linear, status-dependent, and intertemporal constraints are proxied in the present framework by forcing certain generators to tolerate a predefined threshold of negative contribution margins before shutting down. This is implemented as a "run-through premium" for nuclear, lignite, and hard coal plants. For example, the variable cost for a nuclear plant is reduced by 10 €/MWh. In order not to distort its full cost, fixed costs are duly increased by 87600 €/MWa.

B.4 Flexibility options

The model aims to not only capture the major inflexibilities of existing power technologies, but also to model important flexibility options. Transmission expansion and electricity storage can both make electricity systems more flexible. These options are discussed next.

Within regions, the model abstracts from grid constraints, applying a copperplate assumption. Between regions, transmission capacity is constrained by net transfer capacities (NTCs). Ignoring transmission losses, the net export $x_{t,r,rr}$ from r to rr equals net imports from rr to r (12). Equations (13) and (14) constraint electricity trade to the sum of existing interconnector capacity $\hat{x}^{0}_{r,rr}$ and new interconnector investments $\hat{x}^{inv}_{r,rr}$. Equation (15) ensures lines can be used in both directions. Recall from (1) that interconnector investments have fixed specific investment costs, which excluded economies of scale as well as non-linear transmission costs due to the nature of meshed HVAC systems. The distance between markets $\delta_{r,rr}$ is measured between the geographical centers of regions.

$$x_{t,r,rr} = -x_{t,rr,r} \qquad \forall t, r, rr \qquad \text{(B.12)}$$

$$x_{t,r,rr} \le \hat{x}^{0}_{r,rr} + \hat{x}^{inv}_{r,rr} \qquad \forall t, r, rr \qquad \text{(B.13)}$$

$$x_{t,rr,r} \le \hat{x}^{0}_{rr,r} + \hat{x}^{inv}_{rr,r} \qquad \forall t, r, rr \qquad \text{(B.14)}$$

$$\hat{x}^{inv}_{rr,r} = \hat{x}^{inv}_{r,rr} \qquad \forall r, rr \qquad \text{(B.15)}$$

The only electricity storage technology applied commercially today is pumped hydro storage. Thus storage is modeled after pumped hydro. Some storage technologies such as compressed air energy storage (CAES) have similar characteristics in terms of cycle efficiency, power-to-energy ratio, and specific costs and would have similar impact on model results. Other storage technologies such as batteries or gasification have very different characteristics and are not reflected in EMMA. The amount of energy stored at a certain hour $s^{vol}_{t,r}$ is last hour's amount minus output $s^{o}_{t,r}$ plus in-feed $s^{i}_{t,r}$ (16). Both pumping and generation is limited by the turbines capacity $\hat{s}_{r}$ (17), (18). The amount of stored energy is constrained by the volume of the reservoirs $\hat{s}^{vol}_{r}$, which are assumed to be designed such that they can be filled within eight hours (19). Hydrodynamic friction, seepage and evaporation cause the cycle efficiency to be below unity (2). The only costs related to storage except losses are capital costs in the case of new investments $\hat{s}^{inv}_{r}$ (1).

$$s_{t,r}^{vol} = s_{t-1,r}^{vol} - s_{t,r}^{o} + s_{t,r}^{i} \qquad \forall t,r \qquad \text{(B.16)}$$

$$s_{t,r}^{i} \leq \hat{s}_r = \hat{s}_r^{0} + \hat{s}_r^{inv} \qquad \forall t,r \qquad \text{(B.17)}$$

$$s_{t,r}^{o} \leq \hat{s}_r = \hat{s}_r^{0} + \hat{s}_r^{inv} \qquad \forall t,r \qquad \text{(B.18)}$$

$$s_{t,r}^{vol} \leq \hat{s}_r^{vol} = \left(\hat{s}_r^{0} + \hat{s}_r^{inv}\right) \cdot 8 \qquad \forall t,r \qquad \text{(B.19)}$$

EMMA is written in GAMS and solved by Cplex using a primal simplex method. With five countries and 8760 times steps, the model consists of one million equations and four million non-zeros. The solution time on a personal computer is about half an hour per run with endogenous investment and a few minutes without investment.

B.5 Alternative Problem Formulation

In short, the cost minimization problem can be expressed as

$$\min \quad C \qquad \text{(B.20)}$$

with respect to the investment variables $\hat{g}_{r,i}^{inv}, \hat{s}_r^{io,inv}, \hat{x}_{r,rr}^{inv}, \hat{x}_{r,rr}^{dec}, k_{r,h}^{inv}, k_{r,h}^{dec}$, the dispatch variables $g_{t,r,i}, s_{t,r}^{i}, s_{t,r}^{o}$, and the trade variable $x_{t,r,rr}$ subject to the constraints (2) – (19). Minimization gives optimal values of the decision variables and the shadow prices $p_{t,r}, p_{r,t}^{CHPgene}, p_{r,t}^{CHPcapa}, p_r^{AS}$ and their aggregates $\overline{p}_r, v_{r,j}$.

B.6 Graphical Model Formulation

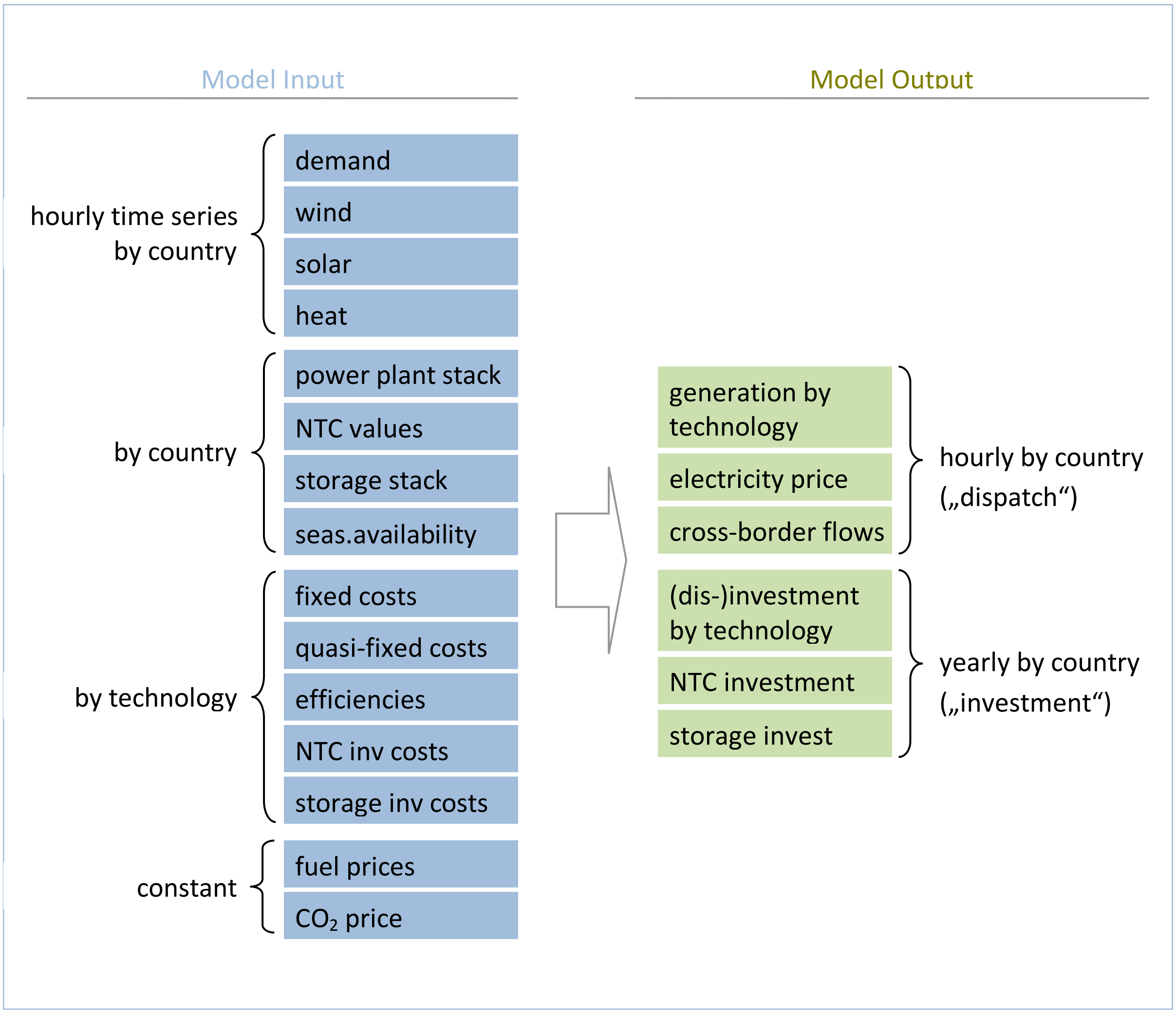

Figure A1: Graphical representation of the model.

B.7 Model Limitations

The model is highly stylized and has important limitations. Maybe the most significant caveat is the absence of hydro reservoir modeling. Hydro power offers intertemporal flexibility and can readily attenuate VRE fluctuations. Similarly, demand response in the form of demand shifting or an elastic demand function would help to integrate VRE generation. Ignoring these flexibility resources leads to a downward-bias of VRE market values.

On the other hand, not accounting for internal grid constraints and VRE forecast errors, the model does not take into account location and balancing costs, overestimating the market value of VRE.

Other important limitations to the model include the absence of constraints related to unit commitment of power plants such as limits on minimum load, minimum up-time, minimum down-time, ramping and start-up costs, and part-load efficiencies; the absence of biomass; the aggregation of power plants into coarse groups; not accounting for market power or other market imperfections; ignoring all externalities of generation and transmission other externalities than carbon; ignoring uncertainty; not accounting for policy constraints (think of the nuclear phase-out in Germany); absence of any exogenous or endogenous technological learning or any other kind of path dependency;

not accounting for VRE resource constraints; ignoring grid constraints at the transmission and distribution level; any effects related to lumpiness or economies of scale of investments.

B.8 Input Data

Table A1: Coefficients of correlation between hourly wind profiles, solar profiles, and demand for Germany and France.

	wGER	wFRA	sGER	sFRA	dGER	dFRA
wGER	1					
wFRA	.33	1				
sGER	-.12	-.11	1			
sFRA	-.08	-.12	.95	1		
dGER	.16	.11	.18	.21	1	
dFRA	.17	.19	-.14	-.13	.70	1

Table A2: Cost parameters of generation technologies.

			investment costs (€/KW)	quasi-fixed costs (€/KW*a)	variable costs (€/MWh$_e$)	fuel costs (€/MWht)	CO_2 intensity (t/MWht)	efficiency (1)
Dispatchable	CHP possible	Nuclear*	4000	40	2	3	-	0.33
		Lignite*	2200	30	1	3	0.45	0.38
		Lignite CCS*	3500	140	2	3	0.05	0.35
		Hard Coal*	1500	25	1	12	0.32	0.39
		CCGT	1000	12	2	25	0.27	0.48
		OCGT**	600	7	2	50	0.27	0.30
		Load shedding	-	-	-	***1000	-	1
VRE		Wind	1300	25	-	-	-	1
		Solar	2000	15	-	-	-	1
		Pumped hydro**	1500	15	-	-	-	0.70

Nuclear plants are assumed to have a life-time of 50 years, all other plants of 25 years. OCGT fuel costs are higher due to structuring costs. Lignite costs include mining.
* Base-load plants run even if the electricity price is below their variable costs (run-through premium).
**Flexible technologies are assumed to earn 30% of their investment cost from other markets (for example regulating power).
***This can be interpreted as the value of lost load (VOLL).

Transmission investment costs are one million Euro per GW NTC capacity and km both for AC and DC lines.

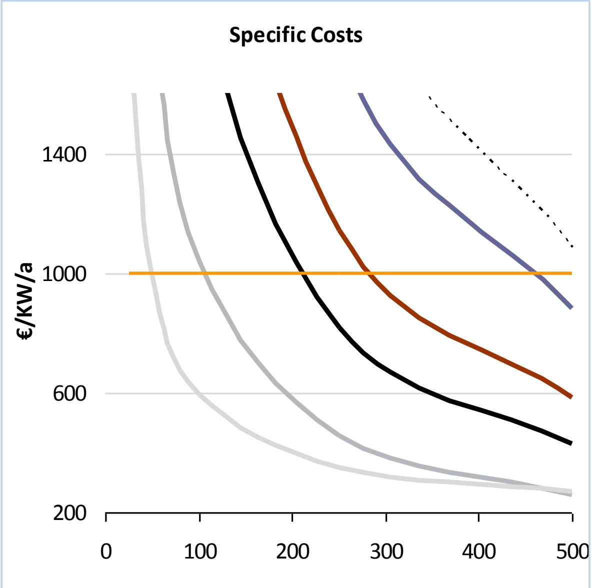

Figure A2a: LCOE of all technologies (peak load) as a function of FLH. Load shedding is the cheapest technology for up to 80 FLH.

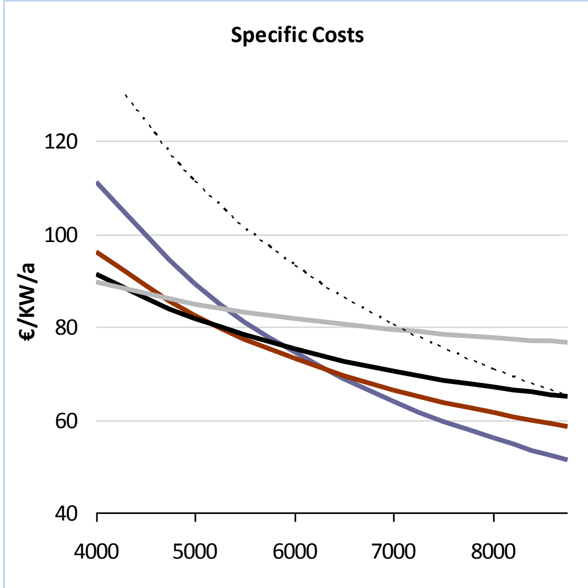

Figure A2b: LCOE of all technologies (mid and base load) as a function of FLH.

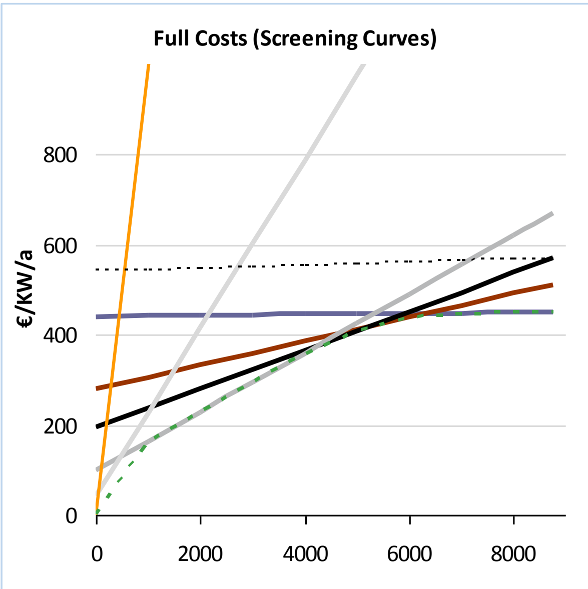

Figure A2c: Screening curves: Specific full costs (€/KW) as a function of FLH for different technologies.