The Optimal Share of Variable Renewables (How Much Wind Should We Build?)

How the variability of wind and solar power affects their welfare-maximal deployment.

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Comments welcome

Abstract

The fact that wind and solar power generation varies exogenously with the availability of the underlying primary energy sources crucially affects their social value. This paper determines the welfare-optimal market share of wind and solar power under different technology, price, and policy assumptions. Special focus lies on the role that variability has on optimal deployment. A numerical electricity market model with high temporal resolution is used to represent variability realistically, and empirical data are used to capture crucial correlations over time and across space. Results indicate that variability significantly limits the role that wind and solar power should play in a cost-optimal energy system. The optimal share of wind power in the current energy system is 7%, but in the long-run equilibrium it is 25%. If wind speeds were constant, the optimal deployment rate would be twice as high.

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1. Introduction

In many European countries electricity generation from renewable energy sources (RES) has been growing rapidly during the last years, driven by technological progress and deployment subsidies. 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 the potential of hydro power is already largely exploited and biomass growth is limited by supply constraints and sustainability concerns, much of the future RES growth will need to come from wind and solar power. Solar and wind power are variable renewable energy sources (vRES)[3] in the sense that supply is determined by non-economic parameters such as weather conditions, in contrast to "dispatchable" generators that vary output as a reaction to price changes. The social value of vRES, defined as the marginal welfare increase due to an additional unit of installed capacity, is affected by two intrinsic properties of vRES:

- The supply of vRES is *variable*. Electricity is not a homogenous good over time, because demand is variable and price-inelastic, the supply curve is upward sloping, and electricity storage is costly. Thus the value of electricity depends on the point of time it is produced.
- The output of vRES is *uncertain* until realization. The last possibility to trade on liquid markets is day-ahead, that is 12-36 hours ahead of delivery. Deviations between forecasted generation and actual production need to be compensated for by other generators or load adjustments. Coordination takes place on intraday and balancing markets. The effect of uncertainty on the market value depends on the size of the forecast errors and on these markets.

This paper provides a cost-benefit analysis of wind and solar power, focusing on their output variability. Specifically, the welfare-optimal market shares of these technologies are determined, taking their variability into account in a realistic manner. Then the effect of policies, prices, and learning curves on optimal deployment is assessed. The effects of uncertainty are beyond the scope of this paper.

The paper is structured as follows. Section 2 reviews the literature. Section 3 outlines an electricity market model that is applied in section 4 to derive optimal penetration rates of wind and solar power. Section 5 summarizes and discusses results and section 6 concludes.

2. Literature review

The welfare-maximal or cost-minimal technology mix for electricity generation has been and continues to be hotly discussed in academia and the policy arena. Three branches of the literature are discussed in the following: integrated assessment models and other multi-sector studies, investment models of the power sector that feature a fine temporal resolution but only model conventional capacities endogenous, and high-resolution models that optimize vRES capacities as well.

Large multi-sector models of the economy are often used to determine the optimal shares of wind and solar in the electricity generation mix. Recently, the European Comission's (2011) Roadmap 2050 finds optimal RES shares of 60-80% in their decarbonisation scenarios based on the PRIMES model. Integrated assessment models like REMIND (Leimbach et al. 2010), GCAM (Calvin et al. 2009), IMAGE (van Vliet et al. 2009), MESSAGE (Krey and Riahi 2009), TIAM (Loulou et al. 2009), MERGE (Blanford et al. 2009), or EPPA (Morris 2008) regularly estimate cost-optimal shares of wind and solar power

[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.

for given greenhouse gas mitigation targets. At an aggregated level, Edenhofer et al. (2011) gives an extensive overview of results. Short et al. (2003) focus on the U.S. power sector, using a more detailed representation of interconnection constraints and wind resources. Haller et al. (2011) provide a similar analysis for Europe. However, all these models lack the high temporal resolution that is needed to model crucial features of the electricity system. The hourly-scale variability not only of vRES, but also of demand in combination with the fact that electricity storage is very costly is *the* key characteristic that makes electricity different from other goods. In other words, electricity is not a homogenous good over time. This has major consequences for the industry, e.g. the existence of a broad set of technologies that differ in their fix-to-variable cost ratio but are used, and crucially affects the cost-benefit analysis of vRES. Multi-sector models usually use yearly or coarser time steps and are not able to capture the consequences of variability.

In the narrower field of power economics, several papers assess the optimal conventional generation mix for a *given* amount of wind and/or solar power. These models are able to model generation capacity endogenously, but do not provide optimal vRES shares. Krämer (2002) uses a linear dispatch and investment model with hourly resolution and German data to derive the cost-minimal capacity mix with and without wind. Similarly, Bushnell (2010) and Green & Vasilakos (2011) estimate the long-term equilibrium with and without wind power. Rosen (2007) and Nicolosi & Nabe (2011) generalize the long-term modelling by including a stack of existing plants. Instead of deterministic modelling, Nagl et al. (2012) use a stochastic dispatch and investment model to derive the optimal conventional capacity mix given certain wind and solar capacities. A closely related branch of the literature discusses the effects of vRES on storage, such Nagl et al. (2011) and Thohy & O'Malley (2011). Three major conclusions emerge from this literature. First, there is a shift from base load to mid- and peak-load technologies with the introduction of vRES. Second, total dispatchable capacity can only be slightly reduced, indicating that vRES has a small capacity credit. Finally, existing conventional generators' income is reduced due to lower running hours and reduced prices (compare Hirth & Ueckerdt 2012 for a more thorough account of the latter finding). However, in all these studies vRES capacity is taken as given and not modelled endogenously and is thus not optimal.

Somewhat surprisingly, only a handful studies derive optimal amounts of vRES capacity while taking the high temporal variability into account. DeCarolis & Keith (2006) derive the cost-minimal electricity mix for Chicago. Electricity can be either provided locally from gas-fired plants, or generated from wind power at five different sites in the Mid West and transmitted to the city. Modelling generation and transmission investments endogenously, the authors derive the cost-optimal capacity mix for different levels of CO_2 pricing. They find that wind investments at the best sites require a carbon price of 150 \$/t and that at 300 \$/t wind investments take place at all sites. All sites are used despite significantly differences in full load hours because geographical dispersion helps levelling out fluctuations. While being an important methodological contribution, generalizing the findings of this case study is not straightforward, given how stylized the electricity system is modelled. Olsina et al. (2007) derive the optimal capacity mix of an entire country, Spain. They find that at investment costs of 1200 €/kW virtually no wind power is installed, but if the costs drop to half that amount, about 20 GW should be installed. A major drawback of this work is that wind profiles (hourly wind generation) are simulated and do not capture correlations across space realistically. Also, the electricity system is modelled in a merit-order approach only, not taking into account must-run constraints, storage, or international trade. In a seminal contribution, Lamont (2008) provides a number of crucial insights into the economics of vRES. Applying a long-term equilibrium model, he finds that no wind power should be deployed if annualized fix costs are 120 \$/kW. If costs drop to 85 \$/kW, a third of total capacity should be wind power. Focusing on the U.S., Brun (2011) finds that under current cost assumptions, wind power should optimally have a share of 6% of installed capacity, with higher shares of up to 20% in the North Central, Mountain, and Pacific regions. A carbon price of 15 \$/tCO_2 increases the optimal share to a swift 37% on average. Doherty et al. (2006) apply a simple linear investment-dispatch model to Ireland, finding the optimal amount of wind capacity strongly dependent on the price of CO_2 and gas. They also find that wind power reduces the long-term volatility of electricity prices that is induced by fuel price volatility. All five papers model the long-term equilibrium, which is a green-field approach that assumes there is no sunk capital stock. Thereby they necessarily ignore the effect that the existing infrastructure has during their remaining life-time. In contrast, Denny & O'Malley (2007) conduct a short-term analysis, assuming conventional capacity as given and not allowing for endogenous investments. Using a linear dispatch model and accounting for wind forecast errors, they estimate benefits and costs of wind power in Ireland. However, instead of maximizing the net benefit they calculate the "critical" amount of wind power, where the net benefit equals zero. Their results indicate that net benefits are highly non-monotonic and peak at around 2 GW installed capacity.

This work belongs to the latter branch of the literature, optimizing vRES capacities endogenously using a model with hourly time steps. It contributes to the literature in three ways. First, it combines endogenous investment modelling with an existing stack of power plants, hopefully making the results more relevant to policy decisions. Second, a model is developed that incorporates a number of crucial features of the electricity system, like must-run constraints of combined heat and power plants, spinning reserve requirements, transmission constraints, and electricity storage. Six North-European countries are modelled using historical wind speeds to capture correlations across space and over time realistically. Both the existing plant stack and these technical features are shown to crucially affect the level of optimal vRES deployment. Finally, the influence of fuel and CO_2 prices, policies, and vRES learning curves on the optimal amount of vRES deployment is assessed. One the one hand, drivers and barriers to vRES deployment are identified and quantified. On the other hand, the sum of parameter changes gives an indication of the uncertainty range of optimal vRES deployment.

3. Model description

To derive optimal vRES market shares under different prices and policies, and in a medium-term model as well as the long-term economic equilibrium, a stylized numerical model of the North-Western European electricity market was developed. The model minimized total costs with respect to investment, production and trade decisions under a large set of technical constraints. Assuming perfect competition, total cost minimization is equivalent to profit-maximization of decentralized agents. The model is linear, deterministic, and solved at hourly resolution for a full year. This section discusses crucial features verbally, outlines model equations and input data, and presents back-testing results. A graphical model representation can be found in the appendix (Figure A1).

4.1 Overview

Generation is modeled as eleven discrete technologies with continuous capacity: two variable renewables with zero marginal costs, wind and solar, seven 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 pump hydro storage. vRES generation is given by exogenous generation profiles. Dispatchable plants produce when the price is above variable costs. Storage is optimized endogenously under turbine, pumping, and storage volume constraints. An energy-only market is modeled. Curtailment is possible at zero costs, which implies that the electricity price does not become negative. The existing power plant fleet is included as sunk investment. New investment is possible in all generation technologies as well as storage and will be done if plants earn a return on investments of 7%. Existing plants are decommissioned if they do not cover their quasi-fixed costs.

Demand is given exogenous by hour and thus assumed to be perfectly price inelastic at all but very high prices, when load is shed. While abstracting from price-elasticity is a standard assumption in dispatch models, it is somewhat problematic with respect to the investment decision, which takes place at longer time scales. However, the average electricity price does not vary dramatically between model runs. Hourly demand as well as wind and solar generation factors are derived from real data of the same year. This ensures that crucial correlations across space, over time, and between parameters are captured.

Combined heat and power (CHP) generation is modeled as a must-run load by technology. That means that a certain share of the heat-providers lignite, hard coal, CCGT and OCGT are forced to run even if prices are below their variable costs. The remaining capacity of that technology is freely available for optimization. Investment and disinvestment in CHP generation is possible, but the total amount of CHP capacity cannot be reduced.

Cross-border trade is endogenous and limited by net transfer capacities (NTCs) while within regions transmission capacity is assumed to be not binding. Endogenous investment in interconnector capacity is possible and done if capacity and generation cost reductions exceed annualized investment costs for interconnectors.

The model is linear and does not feature any explicit integer constraints such as start-up cost, minimum load or minimum downtime conditions. Thus, it is not a unit commitment model. However, start-up costs are parameterized to achieve a more realistic bidding behavior: Baseload plants bid an electricity price below their variable costs in order to avoid ramping and start-ups. Ancillary services are not explicitly modeled. However, it is attempted to proxy their effects on dispatch and investment through a must-run constraint for dispatchable generators, and a proxy for income from reserve markets.

The most obvious caveat of the model is the absence reservoir hydro power. In Nordic, France, Spain, and the Alps significant capacities of long-term reservoir hydro power are available that offer intertemporal flexibility and hence will help keeping up value factors of vRES. For that reason only thermal systems are modeled and results do not apply to hydro systems; French hydro is proxied by reducing demand during peak hours.

The model is calibrated to North-Western Europe and covers Germany, Belgium, Poland, The Netherlands, and France. Back-testing shows that crucial features of the power market can be replicated fairly well, such as price level, price spreads, interconnector flows, peak / off-peak spreads, and the capacity and generation mix.

4.2 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 fix generation costs $C_{r,i}^{fix}$, variable generation costs $C_{t,r,i}^{\mathrm{var}}$, and investment costs into storage C_r^{sto} and transmission $C_{r,rr}^{trans}$ over all generation technologies i, regions r, and time steps t:

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

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 pump 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 $\delta_{r,rr}$, specific annualized investment costs per MW-km c^{NTC}. Investment and generation are decision variables while costs and $\hat{g}_{r,i}^{0}$ are parameters. Hats denote capacities that constrain the respective flow variables; all Roman letters except costs and initial capacities denoted with uppercase zeros are endogenous variables while Greek letters will denote parameters. There are eleven technologies, five regions, and 8760 times steps modelled. Note that (1) does not contain a formulation for distribution grid costs, which in reality is a significant share of household electricity costs.

4.3 Supply and Demand

The energy balance (2) is the central constraint of the model. Demand $d_{t,r}$ has to be met by supply during every hour and in every region. Supply is the sum of generation $g_{t,r,i}$ minus the sum of net exports $x_{t,r,rr}$ plus storage output $s_{t,r}^{o}$ minus storage in-feed $s_{t,r}^{i}$. Storage efficiency is given by η. The electricity price $p_{t,r}$ is defined as the shadow price of demand and has the unit €/MWh (3). Note that (2) features an inequality, implying that supply can always be curtailed and that 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 spot price as being implanted in many deregulated wholesale electricity markets. Since demand is perfectly price-inelastic, cost minimization is equivalent to welfare-maximization.

$$d_{t,r} \leq \sum_i g_{t,r,i} - \sum_{rr} x_{t,r,rr} + \eta \cdot s_{t,r}^{o} - s_{t,r}^{i} \qquad \forall t,r \qquad (2)$$

$$p_{t,r} \equiv \frac{\partial C}{\partial d_{t,r}} \qquad \forall t,r \qquad (3)$$

Generation is constraint by available installed capacity. Equation (4) states the capacity constraint for the vRES technologies j, wind and solar power. Equation (5) is the constraint for dispatchable generators k, which are nuclear, lignite, hard coal, CCGT, and OCGT as well as load shedding. Note that technology aggregates are dispatched, not individual blocks or plants. Renewable generation is constraint by exogenous generation profiles $\varphi_{t,r,j}$ that captures both the availability 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 $c_{r,k}^{dec}$ to save on quasi-fix costs, while vRES capacity cannot. Both generation and capacities are continuous variables. The value factors are defined as the average revenue of wind and solar relative to the base price (6).

$$g_{t,r,j} = \hat{g}_{r,j} \cdot \varphi_{t,r,j} = \left(\hat{g}_{r,j}^{0} + \hat{g}_{r,j}^{inv}\right) \cdot \varphi_{t,r,j} \qquad \forall t,r,j \in i \qquad (4)$$

$$g_{t,r,k} \leq \hat{g}_{r,k} \cdot \alpha_{t,r,k} = \left(\hat{g}_{r,k}^{0} + \hat{g}_{r,k}^{inv} - \hat{g}_{r,k}^{dec}\right) \cdot \alpha_{t,r,k} \qquad \forall t,r,k \in i \qquad (5)$$

$$v_{r,j} \equiv \sum_t g_{t,r,j} \cdot p_{t,r} \Big/ \sum_t p_{t,r} \qquad \forall r,j \in i \qquad (6)$$

Minimizing (1) under the constraint (5) implies that technologies generate if and only if the electricity price as defined in (3) is equal or higher than variable costs. It also implies the electricity price equals variable costs of a plant if the plant is generating, but 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 a proof see Hirth & Ueckerdt 2012).

4.4 Power System Inflexibilities

One of the main ambitions of this model 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. Both heat and ancillary services are goods that are produced jointly with electricity and that limit the flexibility of producers to react to electricity prices. These inflexibilities in conjuncture with subsidies vRES generation are the reason for electricity prices to become negative at times in practice.

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. Most importantly, 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 (7) guarantees that generation of each CHP technology h, 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 $\kappa_{r,h}$ 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 (8). Furthermore, the current total amount of CHP capacity in each region γ_r has to remain at least constant (9). Investments in CHP capacity $\kappa_{r,h}^{inv}$ as well as decommissioning of CHP $\kappa_{r,h}^{dec}$ are possible, but only to the extent that total power plant investments and disinvestments take place (11), (12). Taken together, (8) – (12) allow fuel switch in the CHP sector, but do not allow reducing total CHP capacity. For both the generation constraint (3) and the capacity constraint (5) 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 heat supply.

$$g_{t,r,h} \geq g_{t,r,h}^{min} = \kappa_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,h} \qquad \forall t,r,h \in k \qquad (7)$$

$$\kappa_{r,h} \leq \hat{g}_{r,h} \qquad \forall r,h \qquad (8)$$

$$\sum_h \kappa_{r,h} \geq \gamma_r = \sum_h \kappa_{r,h}^0 \qquad \forall r \qquad (9)$$

$$\kappa_{r,h} = \kappa_{r,h}^0 + \kappa_{r,h}^{inv} - \kappa_{r,h}^{dec} \qquad \forall r,h \qquad (10)$$

$$\kappa_{r,h}^{inv} \leq \hat{g}_{r,h}^{inv} \qquad \forall r,h \qquad (11)$$

$$\kappa_{r,h}^{dec} \leq \hat{g}_{r,h}^{dec} \qquad \forall r,h \qquad (12)$$

$$p_{r,t}^{CHPgene} \equiv \frac{\partial C}{\partial \varphi_{r,t}^{chp}} \qquad \forall r,t \qquad (13)$$

$$p_r^{CHPcapa} \equiv \frac{\partial C}{\partial \lambda_r} \qquad \forall r \qquad (14)$$

Electricity systems require a range of measures to ensure stability across different dimension. These measures are called ancillary services. Many ancillary services can only be supplied by generators while producing electricity, such as 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 (15), similar to Denholm and Margolis (2007): An amount of σ_r of dispatchable capacity has to be in operation at any time. σ_r is set to 20% of the annual peak demand of that region. CHP generators cannot provide ancillary services, but pump hydro storage can provide them while pumping and generating. For a region with a peak demand of 80 GW, at any point of time 16 GW of dispatchable generators or storage have to be online. Note that with a pump capacity of 8 GW this condition could be fulfilled without delivering any electricity to consumers. The shadow price of σ_r, $p_{t,r}^{AS}$,is defined as the price of ancillary services, with the unit €/KW$_{\text{online}}$a (16).

$$\sum_k g_{t,r,k} - \sum_h \kappa_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,h} + \eta \cdot s_{t,r}^o + s_{t,r}^i \geq \sigma_r = 0.2 \cdot \max_t \left(d_{t,r}\right) \qquad \forall t,r \qquad (15)$$

$$p_r^{AS} \equiv \frac{\partial C}{\partial \sigma_r} \qquad \forall r \qquad (16)$$

Finally, thermal power plants have limits to their operational flexibility, even if they don't produce other goods besides electricity. Physical constraints on the temperature gradients of boilers, turbines, and fuel gas treatment facilities and thermodynamic laws imply that increasing or decreasing output (ramping), running at partial load, and shutting down or starting up plants are costly. In the case of nuclear power plants, the physics of nuclear reactions related to Xenon-135 sets further limits on ramping and minimal down time of plants. These multitudes of constraints are proxied in the present framework by forcing certain generators to produce below variable costs. This is implemented as a "run-through premium" for nuclear, lignite, and hard coal plants. For example, nuclear plants' variable cost is reduced by 10 €/MWh. In order to not decrease full costs, fix costs are increased by 87600 €/MWa in turn.

4.5 Flexibility options

The model aims not only at capturing major inflexibilities of existing power technologies, but also to model important flexibility options. Transmission expansion and electricity storage are major possibilities to make electricity systems more flexible and are discussed in the following.

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 (17). Equations (18) and (19) constraint electricity trade to the sum of existing interconnector capacity $\hat{x}_{r,rr}^0$ and new interconnector investments $\hat{x}_{r,rr}^{inv}$. Equation (20) 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 centres of markets.

$$x_{t,r,rr} = -x_{t,rr,r} \qquad \forall t,r,rr \tag{17}$$

$$x_{t,r,rr} \le \hat{x}^{0}_{r,rr} + \hat{x}^{inv}_{r,rr} \qquad \forall t,r,rr \tag{18}$$

$$x_{t,rr,r} \le \hat{x}^{0}_{rr,r} + \hat{x}^{inv}_{rr,r} \qquad \forall t,r,rr \tag{19}$$

$$\bar{x}^{inv}_{rr,r} = \bar{x}^{inv}_{r,rr} \qquad \forall r,rr \tag{20}$$

The only electricity storage technology applied commercially today is pump hydro storage. Thus storage is modeled after pump hydro. Other storage technologies such as compressed air 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 captured in the model. The amount of energy stored at a certain hour $s^{vol}_{t,r}$ is last hour's amount minus generation $s^{o}_{t,r}$ plus in-feed $s^{i}_{t,r}$ (21). Both pumping and generation is limited by the turbines capacity $\hat{s}_r$ (22), (23). 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 (24). Hydrodynamic friction causes 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).

$$s^{vol}_{t,r} = s^{vol}_{t-1,r} - s^{o}_{t,r} + s^{i}_{t,r} \qquad \forall t,r \tag{21}$$

$$s^{i}_{t,r} \le \hat{s}_r = \hat{s}^{0}_r + \hat{s}^{inv}_r \qquad \forall t,r \tag{22}$$

$$s^{o}_{t,r} \le \hat{s}_r = \hat{s}^{0}_r + \hat{s}^{inv}_r \qquad \forall t,r \tag{23}$$

$$s^{vol}_{t,r} \le \hat{s}^{vol}_r = \left(\hat{s}^{0}_r + \hat{s}^{inv}_r\right)\cdot 8 \qquad \forall t,r \tag{24}$$

The model 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 solving time on a personal computer is about half an hour per run with endogenous investment and a few minutes without investment.

4.6 Input Data

Two types of data are inputted to the model: time series data for every hour of the year, and scalar data. Hourly information is used for each region's demand, the heat profile, and the generation profile of wind and solar power. Real data from the same year is used in order to preserve empirical correlations across space, over time, and between variables. Sensitivity tests indicate these correlations are crucial to estimate value factors accurately. For example, the high correlation of 0.94 between German and French wind generation affects strongly the effect of transmission expansion between these countries. Load data were taken from various TSOs. Heat profiles are based on ambient temperature. Historical wind and solar generation data are only available from a few TSOs, and these series are not representative for large-scale wind penetration if they are based on a small number of wind turbines: At higher penetration rate, a wider dispersed wind power fleet will cause the profile to be smoother. Thus vRES profiles were estimated from historical weather data using empirical estimated aggregate power curves. Wind load factors in all countries are scaled to 2000 FLH. Data from 2010 were used for this paper. Table 5 reports coefficients of correlations for a number of time series. Note that wind is quite well correlated with demand, mainly due to seasonality. Note also that solar is highly correlated with demand within days, but not over seasons. Seasonality is so strong that demand and solar generation are negatively correlated in France. Wind in-feed is highly correlated between countries, and even more so if correlations are not calculated from hourly values, but longer time periods. Wind and solar generation are negatively correlated. For an example of generation profiles see Figure A2.

Table 5: Coefficients of correlation between hourly wind profiles, solar profiles, and demand in different countries (2006-11).

	wGER	wFRA	wNLD	wPOL	sGER	sFRA	dGER	dFRA
wGER	1							
wFRA	.44	1						
wNLD	.84	.49	1					
wPOL	.61	.18	.39	1				
sGER	-.12	-.14	-.13	-.12	1			
sFRA	-.08	-.13	-.10	-.08	.95	1		
dGER	.19	.14	.18	.16	.21	.25	1	
dFRA	.14	.17	.16	.18	-.10	-.07	.70	1

Fixed and variable generation costs are listed in Table 6. Availability is 0.8 for all technologies. Summer 2010 NTC values from ENTSO-E were used to limit transmission constraints. CHP capacity and generation is from Eurelectric (2011b). An interest rate of 7% was used for all investments, including transmission and storage and vRES. Transmission investment costs are one million Euro per GW NTC capacity and km both for AC and DC lines. Screening curves and full cost curves of these technologies are displayed in Figure A3.

Table 6: 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		Nuclear*	4000	40	2	3	-	0.33
Dispatchable	CHP Technologies	Lignite*	2200	30	1	3	0.45	0.38
Dispatchable	CHP Technologies	Lignite CCS*	3500	140	2	3	0.05	0.35
Dispatchable	CHP Technologies	Hard Coal*	1500	25	1	12	0.32	0.39
Dispatchable	CHP Technologies	CCGT	1000	12	2	25	0.27	0.48
Dispatchable	CHP Technologies	OCGT**	600	7	2	50	0.27	0.30
Dispatchable		Load shedding	-	-	-	***1000	-	1
vRES		Wind	1300	25	-	-	-	1
vRES		Solar	2000	15	-	-	-	1
		Pump 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 (e.g. regulating power).
***This can be interpreted as the value of lost load (VOLL).

4. Results

The model introduced in section 3 is now used to estimate the cost-minimal (or welfare-maximal) share of wind and solar power. The first set of runs is based on best-guess long-term ("benchmark") assumptions regarding energy system parameters. These parameters are then systematically varied to understand their impact on the optimal wind and solar market share. The benchmark assumptions are:

- CO_2 price of 20 €/t
- hard coal price of 12 €/MWh_t (130 €/t) and gas price of 24 €/MWh_t
- interconnectors have today's NTC values (endogenous investment is possible)
- today's amount of pump hydro storage is available (endogenous investment is possible)
- spinning reserve and CHP must-run constraints hold
- the current plant stack is in place (endogenous investment is possible)
- all generation technologies are available for new investments

For this set of assumptions (and each set of changed assumptions) several model runs were conducted, where costs for wind and solar power were reduced simultaneously in several steps by up to 30% and 60%, respectively. Thus levelized costs of electricity (LCOE) for wind power dropped from 70 €/MWh to 50 €/MWh and solar LCOE from 200 €/MWh to 80 €/MWh. This analytical setup could be called a two-dimensional comparative statics approach, since both vRES generation costs and a second parameter are changed simultaneously. Results will be mostly presented as "market share curves" that show the optimal share of wind in total electricity consumption as a function of cost reductions.

5.1 Benchmark

Under benchmark assumptions and today's costs, in most countries the optimal penetration rate of wind power is zero (figure 1). Social costs are above social benefits, thus wind should not be deployed. In Belgium and The Netherlands however, the local wind profile is more beneficial than elsewhere, such that small amounts of wind power are efficient. If generation costs fall by 30%, wind should be deployed in all countries. Over North-Western Europe, the efficient market share is 7%. The optimal solar market share in all countries is zero, even if generation costs fall by 60% (figure 2). The overall generation mix is only changed slightly (figure 3).

What drives these results? The average electricity price (base price) is around 65 €/MWh in all countries, meaning that a constant source of electricity increases welfare by €65 for each produced MWh. Because wind speeds are positively correlated with demand due to their seasonality, its value is somewhat higher, about 68 €/MWh in Germany (figure 4), or 1.05 of the base price (figure 5). With levelized costs of about 70 €/MWh, wind power is not competitive and is not built. At 30% cost reduction, when full costs drop slightly below 50 €/MWh, wind becomes competitive in all countries – at least at small scale. However, with more wind capacity, electricity becomes less valuable during windy hours, leading to reduced benefits of wind generators. At a market share of about 7%, there is an equilibrium between wind benefits and costs, which is the welfare-maximal amount of wind deployment. In this equilibrium, the base price is reduced to 52 €/MWh, but the value of wind is reduced further to 48 €/MWh or 0.9 of the base price. The wind-weighted price relative to the base price is called value factor, which is a measure of the marginal value of wind compared to a constant source of electricity (Hirth 2012).

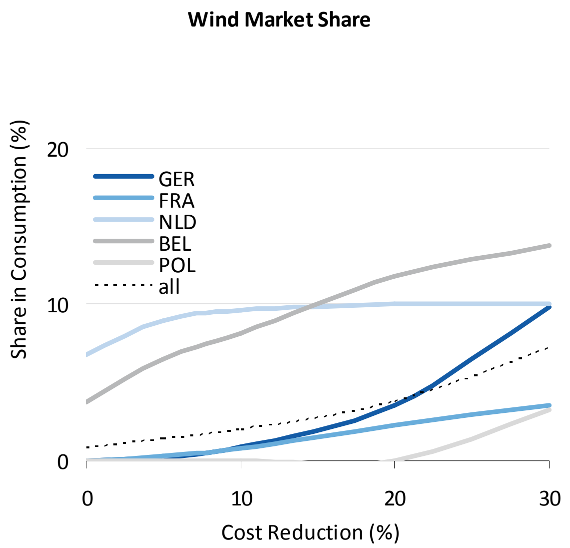

Figure 1: Optimal market shares under benchmark assumptions. In France the existing large inflexible nuclear fleet leads to lower optimal market shares.

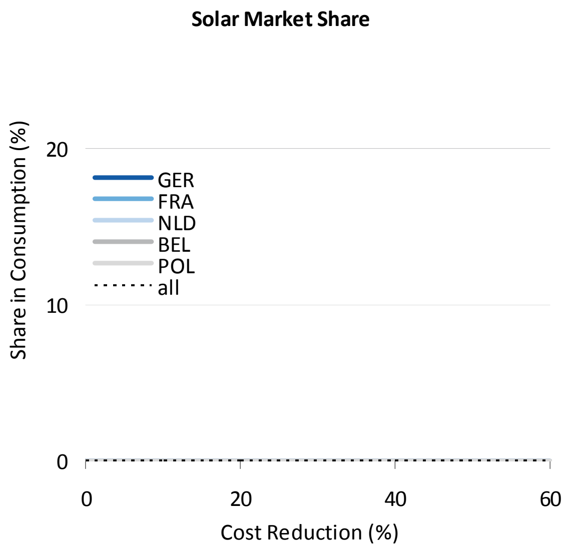

Figure 2: Even at 60% cost reductions, solar power is too expensive to be deployed in North-Western Europe.

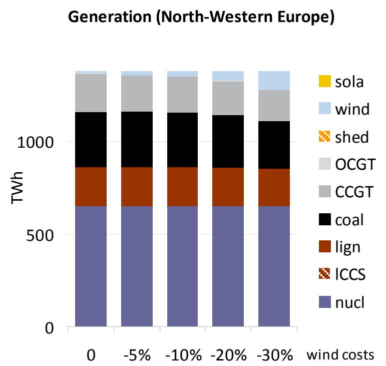

Figure 3: Optimal generation mix. Wind power holds only a minor share of total generation..

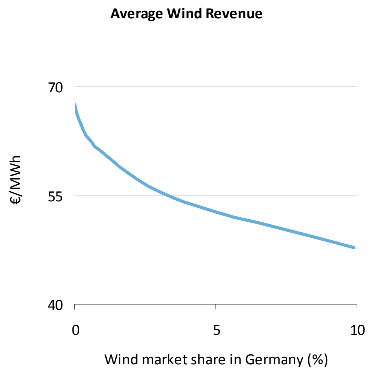

Figure 4: The value of wind power in Germany.

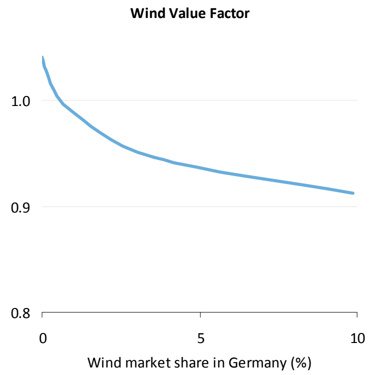

Figure 5: Wind Value factor in Germany (wind's value relative to value of a constant electricity source). Wind power becomes less valuable if more capacity is installed.

To illustrate the effect of wind's variability on its welfare-optimal deployment, the fluctuating empirical wind profile was replaced with a flat profile. At 30% cost reduction, if wind speeds were constant, twice as much wind power should be installed in Germany (figure 6). Results for the regions as a whole a very similar. Thus wind's variability reduces its optimal deployment by half. Figure 7 shows results for France, which are very different. Large amounts of cheap existing base load capacities result in an additional constant source of electricity having little benefit. The fluctuating wind profile, however, has a higher value due to its seasonality. These results highlight how the interaction of existing infrastructure with shocks can shape outcomes.

The main take-away from the benchmark results is that due to its variability, wind power should optimally supply only 7% of European electricity, even if costs fall by 30% from today's level. Solar cannot be efficiently deployed, even if costs are reduced by 60%. In the following paragraphs, the benchmark assumptions are changed one by one to assess the impact that individual factors have on the market value of vRES.

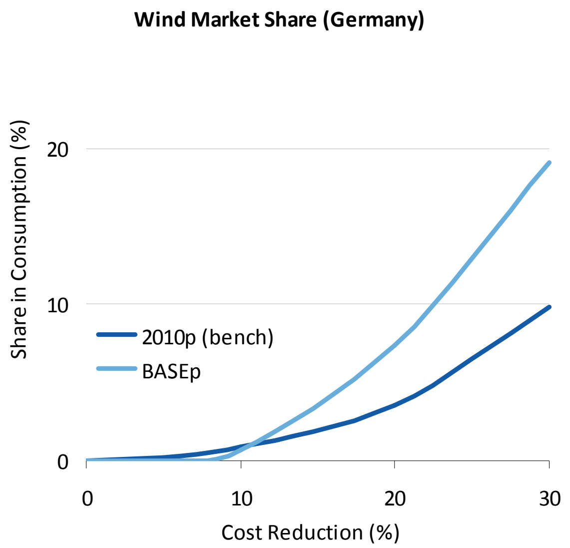

Figure 6: Fluctuating wind profile v. flat (base) profile in Germany. A flat profile is socially more valuable, leading to higher deployment.

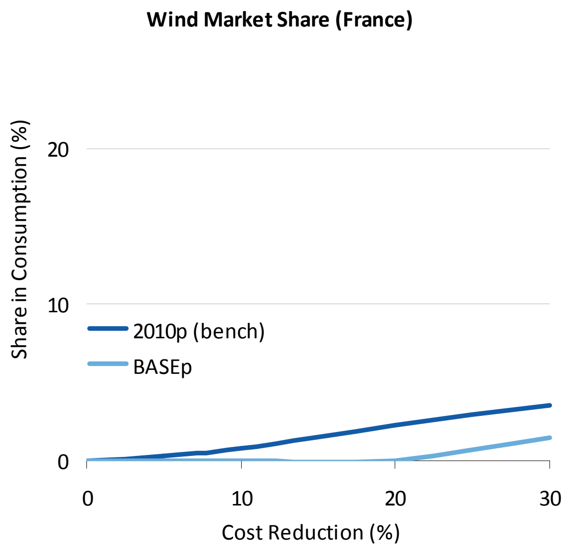

Figure 7: Fluctuating wind profile v. flat profile in France. With large amounts of nuclear power, a flat profile is valued less than the actual wind profile, which is positively correlated with demand due to its seasonality.

5.2 The effect of CO_2 pricing

One of the major drivers of change in the electricity during the last decade has been the introduction of CO_2 pricing, and climate policy will continue to shape the industry's development during the coming decades. Many observers suggest that CO_2 pricing will lead to a higher deployment of vRES. The effect of CO_2 pricing on vRES deployment was tested by changing the benchmark price of 20 €/t to zero, 50 €/t, and 100 €/t.

As one would expect, at a CO_2 price of zero, there is less wind deployment than at the benchmark value of 20 €/t (figure 8). The reason is that low variable costs of emitting plants in conjuncture with large investments in lignite and hard coal capacities (figure 9) reduce the value of wind power to around 47 €/MWh, way below wind LCOEs. A higher CO_2 price of 50 €/t increases wind deployment massively. The optimal wind market share increases to 20% in Europe and to almost 30% in Germany at 30% cost reductions from today. German wind deployment is more responsive to CO_2 pricing due to its high share of carbon-intensive lignite and hard coal. Here comes the surprise: An even higher CO_2 price of 100 €/t *reduces* wind deployment. At such a high CO_2 price, large investments in nuclear power take place. This inflexible base-load technology limits the value of vRES, such that the optimal wind share in Germany is reduced to 15%. In other words: At 100 €/t significant nuclear investments will be efficient. If those are taken, the benefits of additional wind power capacity are quite limited. These findings indicate how important it is to take all capacity developments into account when doing long-term analysis, and they show that policy can have highly non-linear or even non-monotonic effects. Without cost reductions, CO_2 prices of 50-100 €/t are not sufficient to trigger more than 5% market share in Europe. Even at 100 €/t, the solar market share remains around 1%.

While CO_2 pricing has a similar impact in most other countries and in the region as a whole, in France the situation is different (figure 10). Here the large stack of existing nuclear plants changes the impact of CO_2 pricing qualitatively. First, a higher CO_2 price as a much weaker effect on wind deployment: at 50 €/t and 30% cost reduction the optimal share is only 8%, a third of the German value. The reason is that existing nuclear capacity with very low variable costs limit the benefit of additional wind turbines drastically. However, a further price increase to 100 €/t increases wind deployment in France, where it had decreased it in Germany, because no further nuclear investments take place.

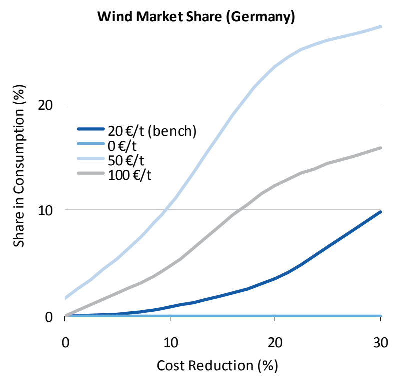

Figure 8: Optimal wind deployment in Germany at different costs of CO_2.

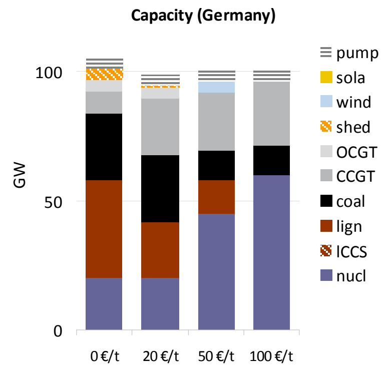

Figure 9: Capacity mix at different CO_2 prices. Wind is driven out of the system because all dispatchable low-carbon options are base load technologies, limiting wind's value.

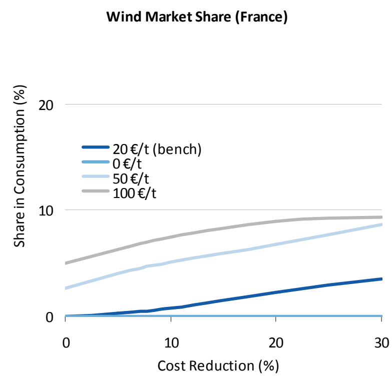

Figure 10: Optimal wind shares in France are lower than in Germany, but increase monotonically with higher CO_2 prices.

Figures 11 and 12 show in more detail the non-monotonic effect of CO_2 pricing on vRES deployment: The optimal wind share increases initially steeply with higher CO_2 prices, peaks at 70 €/t, and decreases afterwards (figure 11). The solar share remains almost flat beyond 60 €/t. This is driven by a dramatic shift towards low-carbon base load technologies (figure 12)

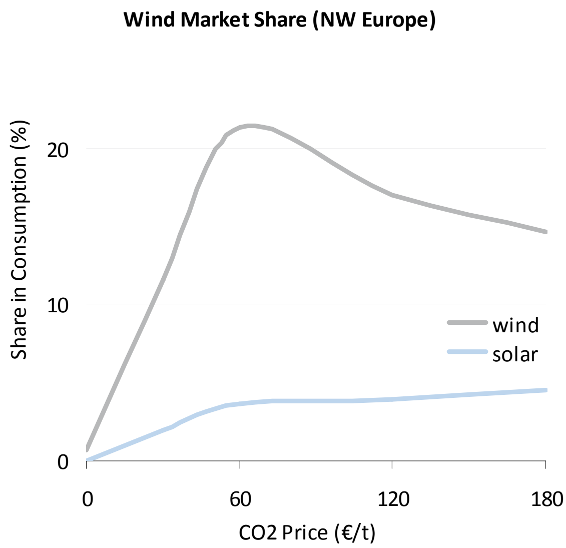

Figure 11: Optimal wind and solar shares at CO_2 prices between zero and 180 €/t.

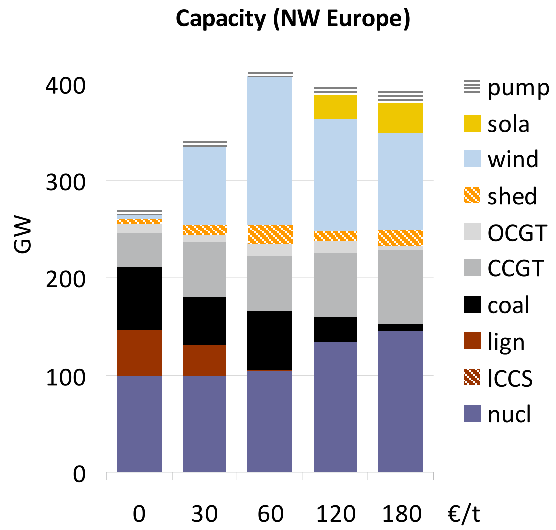

Figure 12: High CO_2 prices induce large nuclear investments, limiting the value of vRES.

These findings are crucially driven by the availability of nuclear as an investment option. Both nuclear and CCS face open questions regarding security, waste, proliferation, carbon storage, and acceptance, which could limit their use in the future. For this reason, in the following nuclear and CCS were not available for new investments. As expected, a high CO_2 price with nuclear and CCS being prohibited increases optimal wind share a lot. In that case, wind power provides 28% of electricity in the social cost-minimum, even without any cost reductions (figure 13). Lowering costs by 30% increases its deployment further to 33%, which would require 100 GW wind capacity in Germany. However, avoiding nuclear and CCS has drastic consequences: The electricity price increases by 12%, CO_2 emissions by 20%, and 10% of all wind generation would need to be curtailed. The solar share remains very low, even at a CO_2 price of 100 €/t, no nuclear power or CCS, and 60% lower solar costs than today (figure 14). The optimal amount of PV capacity in Germany under these extreme assumptions is 16 GW, more than what is already installed today.

Concluding, a CO_2 price higher than 20 €/t increases the optimal amount of wind deployment, but the effect is not monotonic: Very high prices can reduce the optimal amount of wind power. Furthermore, even high CO_2 prices imply an optimal wind share of not more than 20% and are not sufficient for significant amounts of solar power. Only excluding other low-carbon technologies at high CO_2 prices triggers very large amounts of vRES – but even then the vRES share in Europe remains below 30%.

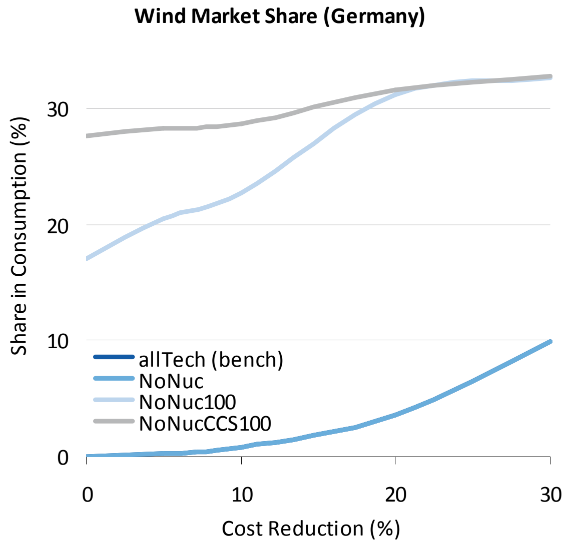

Figure 13: Optimal market shares absent low-carbon dispatchable technologies and with a carbon price of 100 €/t.

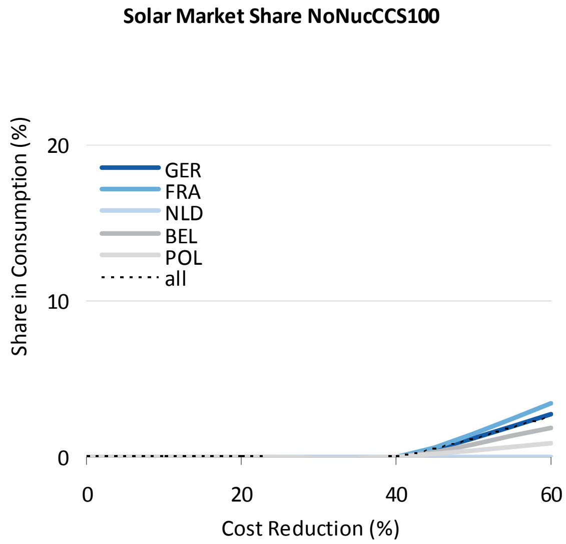

Figure 14: Optimal solar shores. Even at 100 €/t CO_2 and no nuclear and no CCS available, except in France the solar market share remains small.

5.3 The effect of fuel prices

It is sometimes argued that increasing prices for the globally traded fuels hard coal and natural gas are a reason for importing countries to switch to renewable sources, in order to limit import fuel bills. In this section, coal prices and gas prices are doubled separately and simultaneously to understand the effect of higher fossil fuel prices on efficient renewables deployment. As in the case of CO_2 pricing, results might be surprising to some.

At a given amount of renewables, doubling the price of gas and doubling the price of coal has about the same effect on the average electricity price. Higher prices indicate a higher value of electricity, which should make more wind power efficiently deployed. However, while a higher gas price has only modest effects on the optimal amount of wind, doubling coal prices has leads to much higher wind shares (figure 15). As in the case of CO_2 pricing, the reason can be found in capacity adjustments (figure 16). Higher gas prices induce investments in hard coal, which has quite low variable costs, reducing the value of wind power. In the case of 30% wind cost reduction, optimal wind deployment is even *reduced* if gas prices double. Higher coal price, in contrast, induce investments in gas, which, having high variable costs, reduces the value of wind much less.

In France, the picture looks very different (figure 17). Here, a higher gas price leads to increasing optimal wind market shares: In France there is already a large fleet of nuclear plants, and France does not have lignite resources. Thus in France, higher fuel prices do not trigger significant additional base-load investments. Instead, they lead to higher optimal wind deployment. These findings indicate how existing infrastructure and sunk capital stocks interact with price or policy shocks.

Solar power is not deployed in any country.

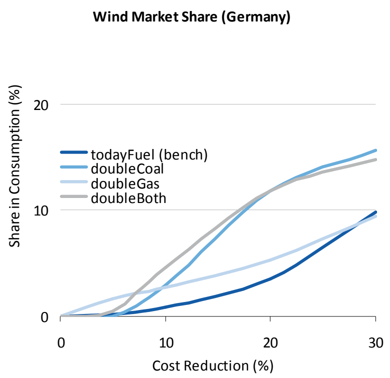

Figure 15: Optimal wind deployment in Germany. Higher fuel prices increase the electricity price, but also trigger investments.

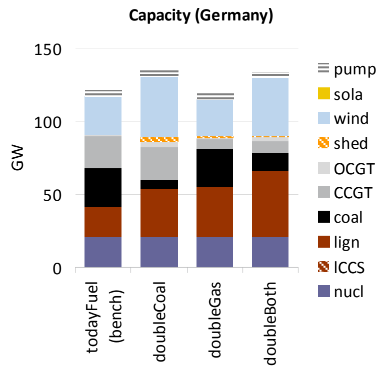

Figure 16: Capacity mix at different fuel prices.

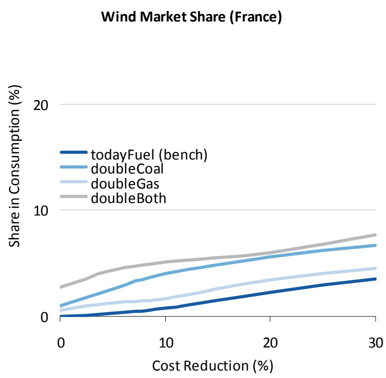

Figure 17: Optimal wind deployment in France is differently affected by CO_2 pricing, because there is a large fleet of existing nuclear plants, limiting the benefits of additional wind..

5.4 The effect of interconnector capacity

Higher long-distance transmission capacity helps to balance out fluctuations in vRES generation profiles. In the present model, international trade is limited by NTC values. To understand the effect of transmission expansion on optimal wind deployment, NTC values were set to zero, doubled from today's level, and set to infinity such that a perfectly integrated market emerges. Overall European optimal wind capacity increases by merely 10% if NTC capacities are doubled and by 50% if transmission was unlimited (figure 18). Furthermore, not all countries benefit. Wind shares in Germany do not rise (figure 19), since the Dutch and the Polish profiles are better correlated with demand, such that large volumes are installed in these countries and then imported to Germany instead of being generated locally. Notably, the optimal European wind market share remains below 10%, even if costs for onshore wind fall by 30% and transmission investments transform North-Western Europe into a perfectly integrated market. This is an important finding of this work: Market integration and transmission investment matter for the amount of efficient wind deployment, but even if they take place, wind's role remains limited.

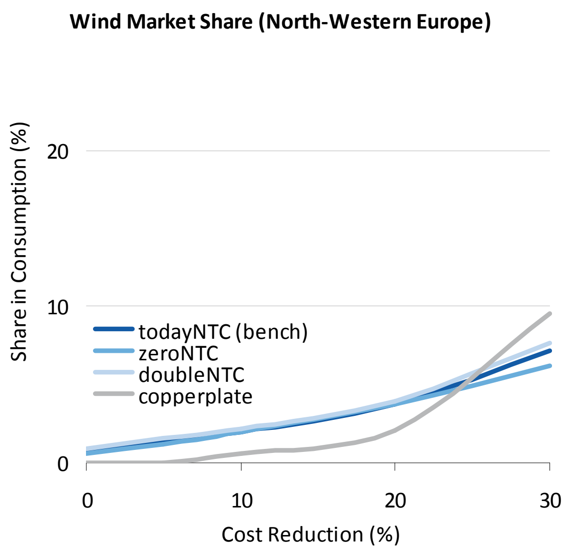

Figure 18: Optimal wind share in Europe. The effect of transmission expansion on the optimal share of wind is very limited. Doubling interconnector capacity increases the optimal share by less than one percentage point.

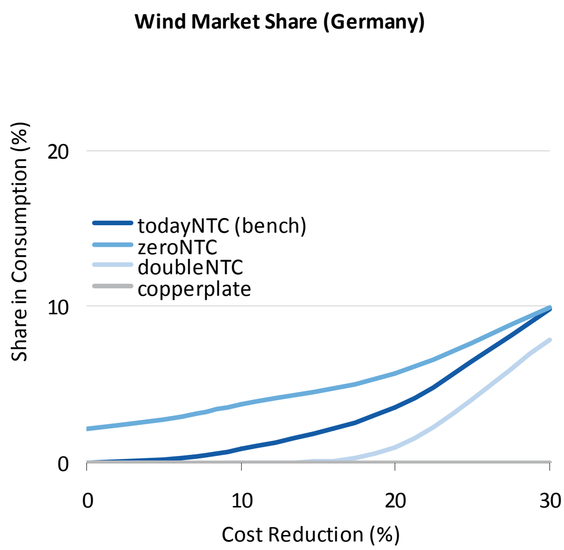

Figure 19: Optimal wind share in Germany under different interconnector assumptions. "Copperplate" means interconnector capacity is not binding at all.

5.5 The effect of storage

Electricity storage is widely discussed as a mean of vRES integration and a prerequisite of system transformation. Here it is tested how the socially optimal deployment of wind is affected by the availability of more or less electricity storage. For that purpose, the amount of pump hydro storage is exogenously set to zero and doubled from today's levels. The surprising result: Wind deployment is virtually unaffected. The reason, besides the limited size of additional storage compared to wind capacities, is that pump hydro is often designed to fill the reservoir in about eight hours while wind fluctuations occur rather on the scale of weeks. Solar power remains inefficient.

5.6 Very high cost reductions

Some observers believe that vRES generation costs could fall even further, driven by fundamental technological breakthroughs. While crucial model assumptions like constant cost parameters for conventional technologies seem to become very strong in the context of technological breakthroughs, indicative results are presented in the following.

If wind generation costs would fall by 60% to 27 €/MWh, wind power would efficiently supply 20% of European electricity (figure 20). If solar costs would fall by 90% to 20 €/MWh, it would supply 17% of electricity consumption (figure 21). For Germany, this corresponds to 75 GW of wind power and 135 GW of solar power. If both wind and solar costs fall that much, they should supply 14% and 11%, respectively (figure 22). These numbers are surprisingly low and indicate how much variability limits very high penetration rates of vRES. Interestingly, even if solar costs fall below wind costs, its optimal market share remains smaller, the reason being the "peaky" solar profile: generation is concentrated in relatively few hours. Once large solar capacities are installed, the social value of generating more electricity during those hours is small.

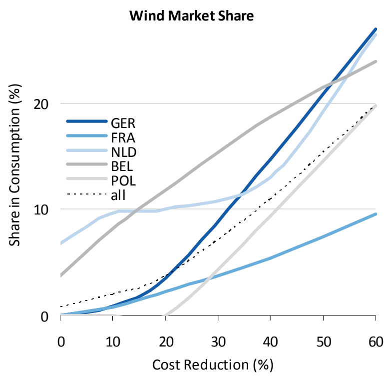

Figure 20: Optimal wind shares at 60% cost reduction.

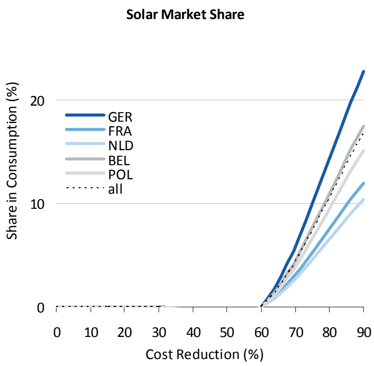

Figure 21: Optimal solar shares at 90% cost reduction.

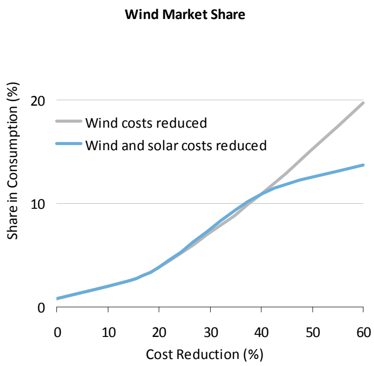

Figure 22: Optimal wind share if wind costs fall, and if solar costs fall as well. Cheap solar reduces optimal wind deployment.

5.7 The long-run equilibrium

Up to this point, the existing generation capacity was taken as given, but decommissioning as well as investment was possible, similar to the approach by Nicolosi & Nabe (2011). In economic terms, this can be labeled a "medium-term" perspective (MacCormack et al. 2010). The mid-term can be understood as the time frame following a shock to the system but before the existing capital stock has fully adjusted to the new long-term equilibrium. Shocks in this sense are both reduction of vRES costs as well as changing benchmark parameters. In a "long-term" view, existing plants have passed their technical life-time and are decommissioned, and all capacity is due to an endogenous investment decision. The outcome of such a long-term analysis is the long-run market equilibrium, where all generators earn their market-rate of return and there are no profits (Hirth & Ueckerdt 2012). Numerical long-term models are discussed in Lamont (2008), Bushnell (2010), Mills (2011), and Green & Vasilakos (2011). The following figures contrast the results from a mid-term (benchmark) run with those in the long-term equilibrium.

Under benchmark conditions, Europe's optimal market share of wind at 30% cost reduction is about 7%. Without existing capacities, it would be more three times higher, reaching 25% (figure 22). Today's capacity mix has a large share of base load technologies. These technologies have low variable costs limit the benefits of wind power, leaving it at a low market share in the social optimum. In the long run, once the existing capital stock has vanished, the optimal capacity mix is shifted towards mid- and peak-load technologies (figure 23). This transformation leads to an optimal market share of wind power of about a quarter. Note that both the mid-term and the long-term run deliver the cost-minimal amount of wind power. The only difference between both setups is that in the mid-term today's capacities are there, while in the long-term they are not. These findings indicate how much the time perspective drives results, and how important it is for studies to be explicit on their assumptions regarding sunk investments. Even at 60% cost reduction, solar power should not be deployed in the long-run.

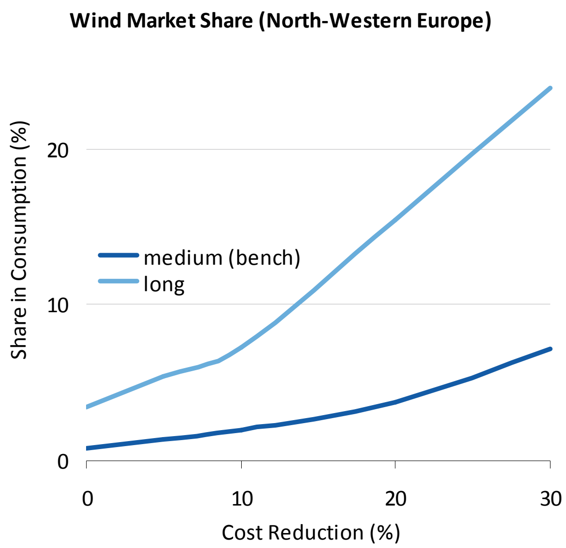

Figure 23: Optimal wind share in Germany with the existing plant stack (medium) and in the long-run equilibrium.

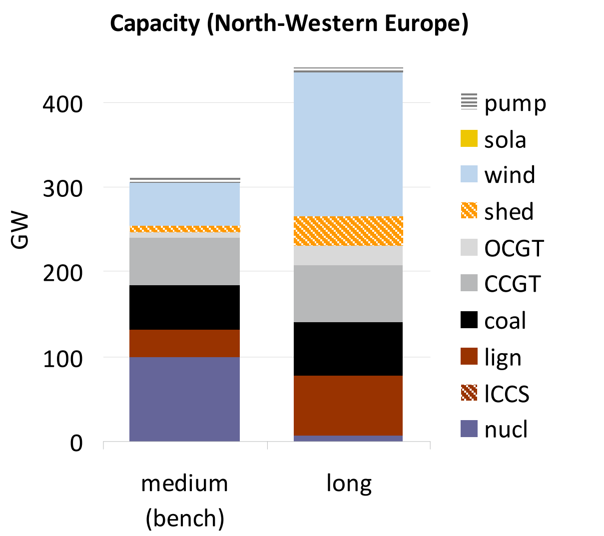

Figure 24: The long-term capacity mix at 30% reduced wind costs entails much less base-load technologies. Today's capacity mix is biased towards base-load technologies and limits efficient wind deployment.

5. Discussion

Figures 25 and 26 show the optimal share of wind and solar power in North-West Europe under all different assumptions used in section 4. While under benchmark assumptions, wind plays a limited role in the optimized generation mix, there are a number of cases where its share is significantly higher. In sharp contrast, solar power cannot be efficiently deployed under virtually all conditions.

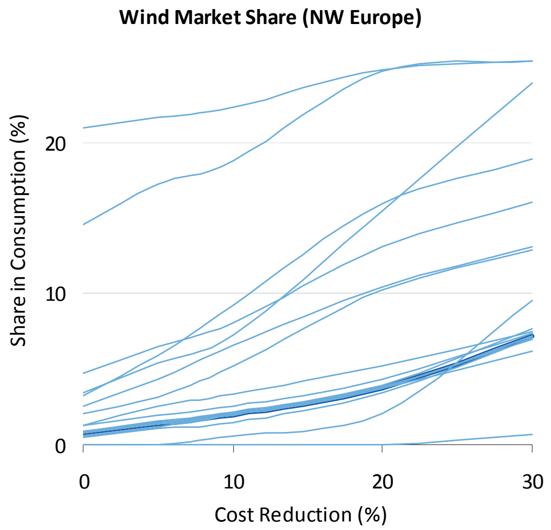

Figure 25: Optimal wind share in Europe in all model runs. Dark blue is the benchmark. The upper line is a CO_2 price of 100 €/t without nuclear or CCS as an investment option. The lowest line shows a CO_2 price of zero.

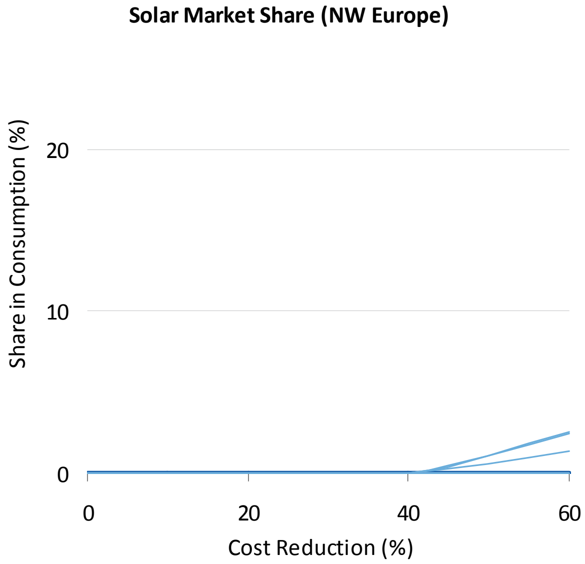

Figure 26: Optimal solar share in Europe. In virtually all parameter settings solar power is an inefficient technology that should not be deployed in North-Western Europe, even if costs decrease 60% from today's level.

6. Conclusions

In this work, a numerical model of the North-Western European electricity system was used to determine the welfare-optimal amounts of vRES technologies wind and solar power. Model results indicate that even at 30% cost reduction for onshore wind power, the optimal share of wind power in the European electricity mix would be below 10%. Wind variability and the existing base load-heavy capacity mix severely limit the benefits of wind power. The factor that most influences optimal wind deployment is CO_2 pricing in combination with the availability of dispatchable low-carbon generation technologies. CO_2 pricing alone, higher fuel prices, more electricity storage, or better interconnections have only limited affect on wind deployment. The time horizon of the analysis crucially drives results: In the long-run equilibrium, wind's market share is 25%, three times the optimal medium-term value.

An important conclusion from these findings is that a low-carbon peak-technology is needed to supplement vRES in the transition to a low-carbon electricity sector. Variable renewables alone won't do the job.

7. References

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8. Appendix

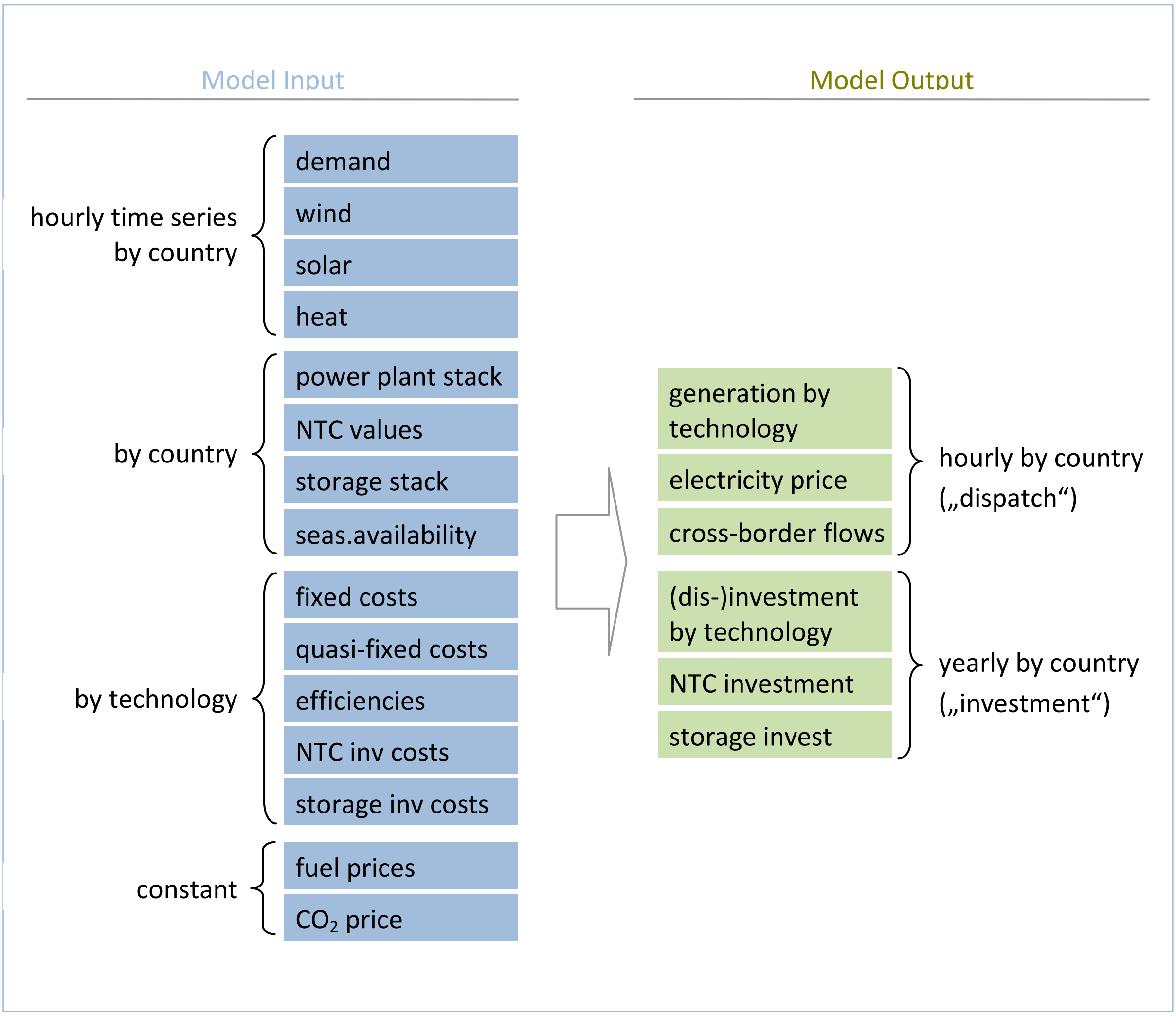


Figure A1: Graphical representation of the model.

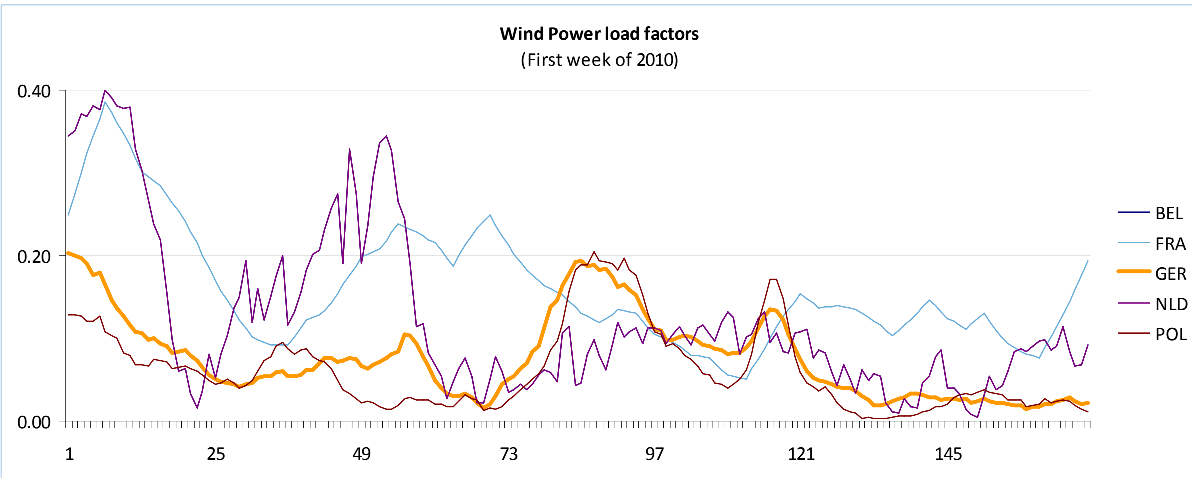


Figure A2: The wind profile for several countries.

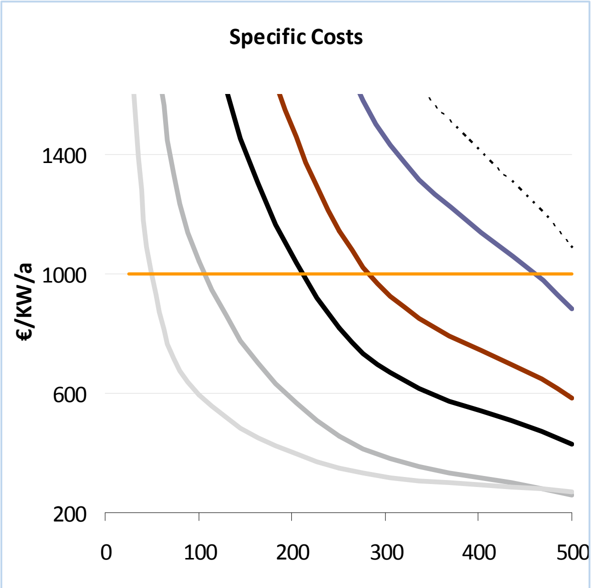


Figure A3a: LCOE of all technologies (peak load) as a function of FLH. Load shedding is the cheapest technology for up to 80 FLH.

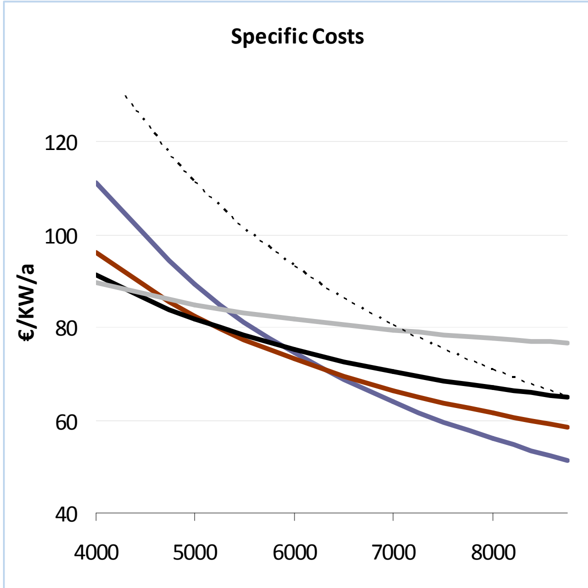
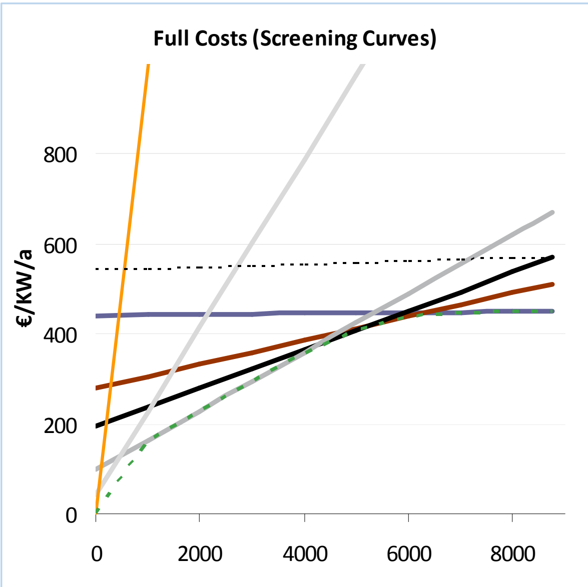


Figure A3b: LCOE of all technologies (mid and base load) as a function of FLH.



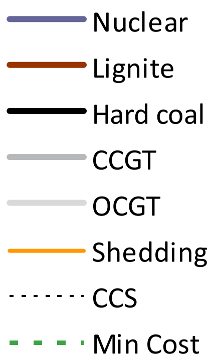


Figure A3c: Screening curves: Specific full costs (€/KW) as a function of FLH for different technologies.