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A Simulation Analysis and the Impact of Grid Extensions[1]

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Abstract:

Given the ambitious, politically-driven wind energy agenda in some U.S. States (e.g., California and Texas) and in Europe (e.g., Germany and Spain), adequate regulatory instruments are needed that provide incentives for additional generation capacity and transmission expansion. This paper analyzes the impact of wind energy extension scenarios in 2020 on the European high voltage grid, using a nodal pricing mechanism and assuming expanded wind generation capacity. Our analysis is based on a DC Load Flow network model that is implemented in GAMS. The results show that the necessary network extensions mostly arise from existing congestion, particularly between countries, and that additional wind capacity can be integrated with relatively little effort. We conclude that the regulatory implications of additional feeding-in of wind energy are less critical than often asserted.

Key words: Electricity, Network Modeling, Wind Integration, Regulation, Europe
JEL-code: L94, L51, D61

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1 Introduction

"Greening the grid" is an often-stated objective in the present discussion about integrating renewable energy into the transmission network. Renewable energies, particularly wind, are considered to provide significant amounts of electricity in a lower-carbon world. Given the ambitious, politically-driven objectives for wind energy in some U.S. States, in Europe, and elsewhere, an adequate regulatory framework is required to provide the proper incentives for additional generation capacities and network expansion. Some instruments, such as uniform pricing of network access, simply do not provide adequate signals for investment and usage.

At first, the issue of additional wind generation was discussed in purely political terms. Proponents hailed it as a clean, sustainable resource, while opponents insisted on the infeasibility of integrating intermittent wind into regular dispatch of electricity. However, recent experience with feeding-in large amounts of wind has shown that the operational issues are manageable, and the resource can be addressed with less ideological pathos, since regulatory decisions mandate wind's role as a key player in the development of European electricity markets. Another aspect of the new debate concerns how additional wind capacities may be efficiently integrated. In the past, wind generation was decentralized and its impacts on the grid were generally quite minor. However, factoring in onshore and, more importantly, projected construction of offshore capacities, gives rise to questions about wind's growing impacts, especially whether the existing grid is still capable of reliably securing energy supply in the integrated network.

Regarding the functionality of liberalized electricity markets, the economic literature distinguishes primarily three issues. First, the literature on the efficient operation of the existing network analyzes how to set efficient electricity prices to reflect the potential scarcity of transmission capacity. It has become clear that realistic modeling includes coping with non-convexities which can produce ambiguous results. Schweppe et al. (1988) show that efficient prices differ by location and over time due to the network's physical characteristics and the different demand situations. Their seminal work defining nodal pricing or locational marginal pricing (LMP) has since then (???) become an essential ingredient. Based on Hogan's work (1992) on contract networks, LMP is used as a pricing tool for several types of market studies. Nodal pricing guarantees theoretically and practically the highest utilization of an existing grid because both generation and transmission constraints are considered when calculating electricity prices. Nodal pricing can be used to carry out economic analysis under technical grid constraints.[2] In Europe, the introduction of cross-border nodal pricing is somewhat tardy; greater market integration requires coordination from several sovereign countries that tend to emphasize national interests. Accordingly, Boucher and Smeers (2002) analyze the future organization of cross-border trade in the European market, concluding that the economic principles proposed by the European Commission in 2001 are insufficient. Ehrenmann and Smeers (2005) analyze Regulation

[2] Compare Green (2007) for England and Wales, Stigler and Todem (2005) for Austria, Leuthold et al. (2008a) for Germany and Northwest Europe.

1228/2003 and conclude that market integration is entirely possible, but that making allowances for political reasons will result in economic inefficiencies.

The second issue is efficient transmission expansion. There is a debate about who should carry it out: a regulated entity (centralized transmission planning, or CTP), or the market (merchant transmission investment, or MTI). The objective of a standard CTP approach is to maximize (expected) social welfare, whereas under MTI the investor should be incentivized by positive return on investment (ROI). Also, the investor should participate in the effect that the investment has in the light of network externalities and the question how to deal with the risk that comes with a transmission investment for both the new investor and the existing transmission owner is still unanswered. Bushnell and Stoft (1996) distinguish contracts for differences (CFD) to hedge temporal price risks and transmission congestion contracts (TCC) that pay the owner the locational price difference between the two nodes specified in the contract. Bushnell and Stoft base their analysis on a contract network regime as proposed by Hogan (1992) and find that in this case TCCs provide the correct incentives for network investments. Chao and Peck (1996) use the nodal pricing methodology and design tradable transmission capacity rights that are able to combine a competitive market for transmission services and a competitive spot market for electricity. They suggest a trading rule for these transmission capacity rights that combine a Coasian property right approach to transmission congestion and the Pigouvian principle to account for network externalities. Joskow and Tirole (2000), however, distinguish two types of tradable rights: financial transmission rights (FTRs)[3] and physical transmission rights. FTRs are financial instruments that entitle or oblige the holder to receive or make payments in case of congestion. Physical rights give the holder the right to transmit electricity even in congestion scenarios. The two authors find that in instances of loop flow effects physical rights can be withheld and thus are likely to be misused in order to exert market power. Thus, they favor FTRs where physical withholding is not possible.[4] On the other hand, Baldick (2007) argues that border flow rights (BFRs) make FTRs dispensable, and states that BFRs resolve the property-rights issues for existing and new transmission capacity arising from new investments. Brunekreeft and Newbery (2006) focus on the welfare effects of a must-offer provision of line capacity in the case of MTI. They conclude that the regulatory instrument of a must-offer provision, has positive short-term welfare effects but may lead to underinvestment in network assets. They do not recommend applying must-offer provisions. Other authors look at the risk associated with a MTI decision under uncertainty (Salazar et al., 2007; Saphores et al., 2004). Among the CTP approaches, Vogelsang (2001) analyzes transmission cost and demand functions assuming rather general properties, and adopts established regulatory adjustment processes based on a two-part tariff cap for transmission. Hogan et al. (2007) and Rosellón and Weigt (2008) extend this two-part tariff approach accounting for loop-flow properties of an electricity network. Sauma and Oren (2006) compare a three-period proactive network planning (PNP) model to a combined generation-transmission operation and investment planning as

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[3] According to Joskow and Tirole (2005), the terms TCC and FTR are interchangeable.

well as to a transmission-only planning model. They conclude that PNP can correct some of the shortcomings of the transmission- only planning and claim that it is a valuable economic assessment methodology. The expected social gains by the PNP methodology should be distributed to all market players through side payments (Sauma and Oren 2007).

The third research issue suggests joint treatment of congestion management and investments in an effort to identify a market design that is consistent with the requirements of the electricity sector and that captures all relevant aspects (e.g. Hogan 2002; Joskow 2007). Joskow and Tirole (2005) point out that transmission investment is influenced by congestion management schemes and the mitigation of market power issues, lumpiness of transmission investment decisions, stochastic elements of transmission networks, and the like. Looking at the compatibility of investment signals in transmission and generation, Pérez-Arriaga and Olmos (2006) propose to apply a locational transmission tariff in addition to LMP which should serve as long-term signal. Rious et al. (2008) analyze whether a two-part tariff is able to incorporate short- and long-run issues to manage electricity networks efficiently. Based on a two-node network, they find that a joint implementation of nodal pricing and an average participation tariff is favorable for combining generation and transmission investment. However, the optimal set of generation and transmission investments may not be utilized because of transmission lumpiness.

To date, the research on electricity networks and renewables emphasizes technical issues relating to network integration and expansion. A study from the German Energy Agency (DENA 2005) that analyzes the costs of integrating additional wind capacity in the German grid finds that extensions to resolve emerging network bottlenecks would be cost-intensive. Other technical studies with similar results look at Poland (PSE 2003), France (Verseille 2003), the Netherlands (Hondebrink et al. 2004), Austria (Haidvogel 2002), Denmark (Woyte et al. 2005) and Spain (IDEA 2005).

A characterization of the aforementioned economic literature is their focus on rather small two- or three-node networks. The above mentioned technical reports have a larger view. However, results from large-scale economic models on network investments have not yet been report to our knowledge. Rather than modeling two- or three-node networks, this paper considers the larger scale. We develop an economic model to calculate the optimal extension of electricity networks taking into account additional capacities of wind energy (onshore and offshore). We use the CTP approach and assume that a centralized network operator desires to maximize welfare under perfect competition. We suggest that nodal pricing is the adequate regulatory framework to facilitate the integration of wind, because it provides price signals and indicates potential congestion; thus, we can estimate the impact of additional wind energy by analyzing price situations. Strong price differences between neighboring nodes help to identify highly congested lines in different scenarios. A special grid-extension algorithm allows our model to extend the grid incrementally until an economically optimal grid status is identified that is capable of carrying the additional wind.

[4] The interaction between imperfect markets and investment decisions is also addressed by Borenstein et al. (2000) and Léautier (2001).

The remainder of the paper is structured as follows: Section 2 presents our model based on Schweppe et al. (1988) and Todem and Stigler (2005). The network topology, the data set and our scenarios are described in Section 3. Choosing Europe as the study area is based on data availability and the ambitious goals for wind expansion in many European countries, such as Germany, Spain, the UK, and France. Section 4 presents the results of the model runs, scenario analysis and interpretation. Our model is able to identify the socially valuable investment locations. Interestingly, most of the necessary line extensions are not due to the large increase of wind energy in the next decade but are necessary to overcome already existing bottlenecks particularly at the country borders. Overall the investment amount needed to cope with increasing wind energy is low compared to the resulting welfare gain. Furthermore, a more equalized increase of wind capacities in the European countries can help to cancel out current local network problems. The paper concludes in Section 5 that the efforts to prepare the European grid for large amounts of wind generation capacities appear rather modest.

2 Model

2.1 Assumptions

This paper examines the impact of wind energy on the grid for the forecasted scenarios in 2020. We assume that the conventional power plant fleet does not change from today to 2020 and simulate feeding the forecasted wind into the existing system. We also assume a feed-in guarantee for wind, which is the dominant scheme applied in Europe (e.g., Germany and Spain). An optimization problem is formulated that calculates the welfare for the electricity system regardless of country or state borders. We assume either a single entity managing the grid or perfect coordination between different entities, and neglect imperfect market functioning (i.e. a perfect competition approach).

2.2 Optimization problem

To calculate the scenarios we apply ELMOD, a model of the European electricity market as described by Leuthold et al. (2008b). The optimization for all scenarios is based on maximizing social welfare W that equals total consumer benefit minus the cost of generation needed to satisfy demand. Thus, welfare corresponds to the unweighted sum of consumer and producer surplus. We assume a liner inverse demand function $p_n(q_n)$ for each node where p_n is the nodal price at node $n \in N$ and q_n is the demand quantity at node n. Optimal dispatch is determined respecting physical laws and technical conditions, namely energy balance (equation 2), line capacity (equation 3) and maximum generation capacity (equation 4) constraints:

$$\max_{q_n, g_{nt}} W = \sum_N \left(\int_0^{q_n} p_n(q_n)\, dq_n - \sum_t c_{nt} g_{nt} \right) \tag{1}$$

$$s.t. \quad \sum_T g_{nt} - q_n - i_n = 0 \ \forall n \quad \text{energy balance constraint} \tag{2}$$

$$|P_l| \leq P_l^{\max} \ \forall l \quad \text{line flow constraint} \tag{3}$$

$$g_{nt} \leq g_{nt}^{\max} \ \forall n,t \quad \text{maximum generation constraint (per plant type)} \tag{4}$$

We assume constant marginal costs c_{nt} for each generation g_{nt} at a node *n* depending on plant type *t* ε *T.* Additional costs, such as those arising from network operation and maintenance as well as start-up costs and ramping conditions are not considered. Power flow P_l and transmission losses are obtained using the DC Load Flow network model (DCLF) described by Schweppe et al. (1988) and Stigler and Todem (2005). Transmission losses are included by splitting them between the start and end nodes of a line *l* as presented by Todem (2004). Hence, losses are represented within the net input i_n that defines the amount of energy that is injected or withdrawn from the network at node *n*. To account for the (N-1)-constraint, we use a transmission reliability margin of 20%; thus the P^{max} of each line *l* is 80% of the full thermal limit. The reference period is one hour. Since the approach is time static, we calculate different scenarios to simulate changing external conditions. The optimization is coded in GAMS and solved on an Intel Xeon CPU E5420 (8 cores) machine with 16 GB RAM.

2.3 Grid extension algorithm

The objective is to estimate the amount of necessary grid extensions to cope with increasing wind energy inputs. We apply an algorithm that gradually extends the grid (upgrading existing lines). In a first step the model calculates the weighted average nodal prices for each node out of four representative standard load and wind generation cases (low wind and low load, low wind and high load, high wind and low load, high wind and high load) for each extension scenario: high load corresponds to the average value of the highest 33% of hourly demand in 2006 and low load to the average level of the remaining 67%. High wind corresponds to a wind input level of 80% of available installed capacities and low wind to a level of 20%.

Next, the model identifies the most severely congested line (identifying the line between the two nodes with the highest price difference). This line is then extended by adding another circuit of the same kind at the same link, simulating a line extension in the form of adding one additional parallel line to an existing connection. We assume that this type of extension measure is possible on each circuit of the model. However, our model does not allow for more than four parallel circuits on one connection. If this constraint becomes binding, the line with the second highest price difference is extended and so on.

After each extension step *it*, the model performs a run and determines the new welfare value and the welfare change $\Delta W_{it} = W_{it} - W_{it-1}$. We then compare the welfare change to the investment effort required to implement the respective grid extension. If the costs are higher than the change of welfare, the line is not considered for further extensions. The model stops if no welfare gain is obtained for 50 extension steps.

2.4 Investment costs

We use the discounted value of the annual depreciation of the investment costs for the particular extension measure. The discounted annual depreciation value is calculated by multiplying the initial costs for the particular extension measure with the annuity factor *ANF*:

$$ANF = \frac{r \cdot (1+r)^k}{(1+r)^k - 1}$$

where r represents the weighted average capital costs (WACC) and k the given period. The WACC is calculated as:

$$r = \left(\frac{E}{TC}\right) \cdot r_E + \left(\frac{DC}{TC}\right) \cdot r_{DC}(1-s)$$

with E for equity, TC for total capital, r_E for equity yield rate, DC for debt capital, r_{DC} for interest on debt capital and s for tax rate. The rate r_E is determined using the Capital Asset Pricing Model (CAPM):

$$r_E = r_f + (\mu_m - r_f) \cdot \beta$$

with r_f for the risk-free rate of return, μ_m the market rate of return and β the risk factor. We choose a given period (k) of 12 years, 25% equity ratio (E/TC), = 6% interest on debt capital (r_{DC}), 40% tax rate (s), 3.5% risk-free rate of return (r_f), 13% market rate of return (μ_m) and 0.9 as risk factor (β). Based on these assumptions, the annuity factor *ANF* is 11.75%. According to DENA (2005), the investment required to upgrade a 150kV/220kV and a 380kV is 70,000 €/km and 120,000 €/km respectively. The capital expenditure for upgrades to be compared with the welfare increase is calculated by multiplying the specific price per km with the length of the upgraded line divided by 8,760 hours.

3 Data and Scenarios

3.1 Data

The model is based on the UCTE extra high voltage grid (UCTE 2004) of the European Union and Switzerland. It includes Portugal, Spain, France, the Netherlands, Belgium, Luxemburg, Denmark, Germany, Switzerland, Austria, Italy, Poland, the Czech Republic, Slovakia, Hungary and Slovenia. The basic model consists of 2120 substations (nodes) and 3143 lines. Three voltage levels, 380kV, 220kV and 150kV, are considered.

To apply the DC load flow model, different line parameters are required: voltage levels, thermal limits, line resistances and line reactances. For each voltage level we select a reference line type, neglecting impacts of the wide range of different lines. For 380 kV, four cables per wire, for 220 kV, two cables per wire, and for 150 kV, one cable per wire are assumed and the thermal limits are derived accordingly (Fischer and Kießling 1989). In our model these maximal allowable power flows are multiplied by the number of circuits, neglecting impacts of influence between multiple circuits. Values for the resistances and reactances of high voltage circuits are subject to empirical experience. We assume average values based on Fischer and Kießling (1989).

Generation capacities are based on VGE (2005). Eight types of conventional power plants are classified and each plant is assigned to one class according to the main fuel type (Table 1). Base case wind capacity information derives from several sources. For Germany we use a pro rata distribution for the nodes in each federal state based on ISET and IWET (2002). For other countries the wind capacity distribution is based on publicly available information, mainly from national wind energy associations.[5] For Italy, Portugal and the new European Union member states, apart from Poland, no such data is available. Hence, the regional allocation of existing wind energy capacity is approximated, taking geographical and meteorological conditions into account. For Poland, the Polish Wind Energy Association (PWEA 2007) provides detailed information about the locations of the existing 150 MW installed wind capacity.

The node-specific generation costs are calculated on the basis of marginal costs, including fuel costs, but not accounting for operating and service costs. Wind power generation is assumed to have no marginal generation costs. Thus indirect costs of stochastic wind input causing higher balancing and response power costs are neglected. Pumped storage is assumed to store during night hours (from 8 p.m. to 8 a.m.) by purchasing electricity on the stock exchange. Marginal costs of conventional plant types are adopted for two reference cases (see Section 3.2).

To obtain a node-specific reference demand, we use the regional GDP (Eurostat 2005) as proxy for electricity demand. We assume that provinces with high economic output – and, respectively, with a high share in the countries' GDP – have a high electricity demand. Consequently, the total electricity consumption is divided according to the GDP share. Within a province, the demand is distributed equally over all nodes.

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[5] EMD (2005), EWEA (2005), IG Windkraft (2005), Wind Service Holland (2005), and AEE (2007).

Table 1: Conventional power plant capacities in Europe

Fuel	Installed capacity [GW]	Fuel	Installed capacity [GW]
Coal	99.2	Natural gas	49.0
Lignite	44.2	Fuel oil	62.4
Nuclear Power	107.3	Water	36.0
CCGT	13.7	Pumped storage	23.3
		Total	***435.1***

Source: VGE (2005).

3.2 Three Scenarios

We consider three scenarios: Benchmark, WEO (World Energy Outlook), and WF12 (Wind Force 12). The Benchmark scenario uses 2006's installed wind energy capacity according to DEWI (2006). WEO applies the wind extensions according to the World Energy Outlook 2006 (IEA 2006) of 114 GW. WF12 includes the alternative wind extension scenario according to the study WF12 (GWEC 2005).

Although both extension studies analyze the energy developments on a global level and for different time horizons, it is possible to extract data for Europe. The studies use the same geographical sectioning, namely OECD Europe which includes the EU-15 countries as well as the Czech Republic, Hungary, Iceland, Norway, Switzerland and Turkey. The countries of OECD Europe that are not included in the UCTE grid are Finland, Sweden, Norway, Greece, Ireland, Iceland, Norway, Turkey, and the UK. Taking into account political, geographical and meteorological conditions, we assume that 22% of the forecasted wind energy capacities will be installed in the countries that are not in the UCTE grid (with a high amount being allocated to high wind resource countries, e.g., the UK and Scandinavia). The time horizon is not identical in both studies; WF12 projects to 2020 and WEO to 2015 and 2030. In the latter case we assume a linear growth in order to make a linear interpolation possible. In 2020, GWEC (2005) forecasts 180 GW total installed wind capacities and IEA (2006) forecasts 114 GW total installed wind capacities under the described assumptions. Since the forecast studies do not give detailed regional information but our model uses accurate regional wind capacities, we allocate the additional capacities to federal states or similar administrative areas. Table 2 shows the obtained wind capacities.

We do not consider changes in the demand or generation structure. Thus the approach is a ceteris paribus analysis. However, we assume two different generation costs cases with respect to the price of emission allowances (EUA): an average CO_2-price of 20 €/EUA and a high CO_2-price of 50 €/EUA. Since wind generation has assumed marginal costs of zero the welfare effect increases with higher costs for those fossil fuels that are replaced by wind input. Respectively, with higher CO_2 prices we expect to observe a larger amount of economic feasible grid extensions. Table 3 summarizes the applied generation costs.

Table 2: Wind generation capacities in 2020 forecasts

	Installed Wind Capacity [GW]		
Country/State	**Benchmark (by end of 2006)**	**World Energy Outlook**	**Wind Force 12**
Austria	1.0	5.2	8.0
Belgium	0.2	0.2	0.3
Czech Republic	0.0	3.3	5.0
Denmark	3.1	2.6	4.0
France	1.6	11.7	18.0
Germany	20.6	31.3	48.0
Hungary	0.1	6.5	10.0
Italy	2.1	9.8	15.0
Luxembourg	0.0	0.1	0.1
Netherlands	1.6	3.6	6.0
Poland	0.2	10.7	18.5
Portugal	1.7	3.3	5.0
Slovakia	0.0	1.3	2.0
Slovenia	0.1	0.7	1.0
Spain	11.6	24.1	40.0
Switzerland	0.0	0.1	0.1
Total	***43.9***	***114.5***	***181.0***

Source: IEA (2006), GWEC (2005), EWEA (2006), own calculations.

Table 3: Generation costs

Fuel	**CO_2 price: 20€/EUA**	**CO_2 price: 50€/EUA**	**Fuel**	**CO_2 price: 20€/EUA**	**CO_2 price: 50€/EUA**
Nuclear Power	15.15	15.15	Natural Gas	67.00	83.50
Lignite	37.14	67.14	Fuel oil	94.71	114.21
Coal	37.54	61.54	Running water	0.00	0.00
CCGT	42.64	53.14	Pump storage	40.00	40.00

Source: Bafa (2008), own calculations.

4 Results and Interpretation

4.1 Price results

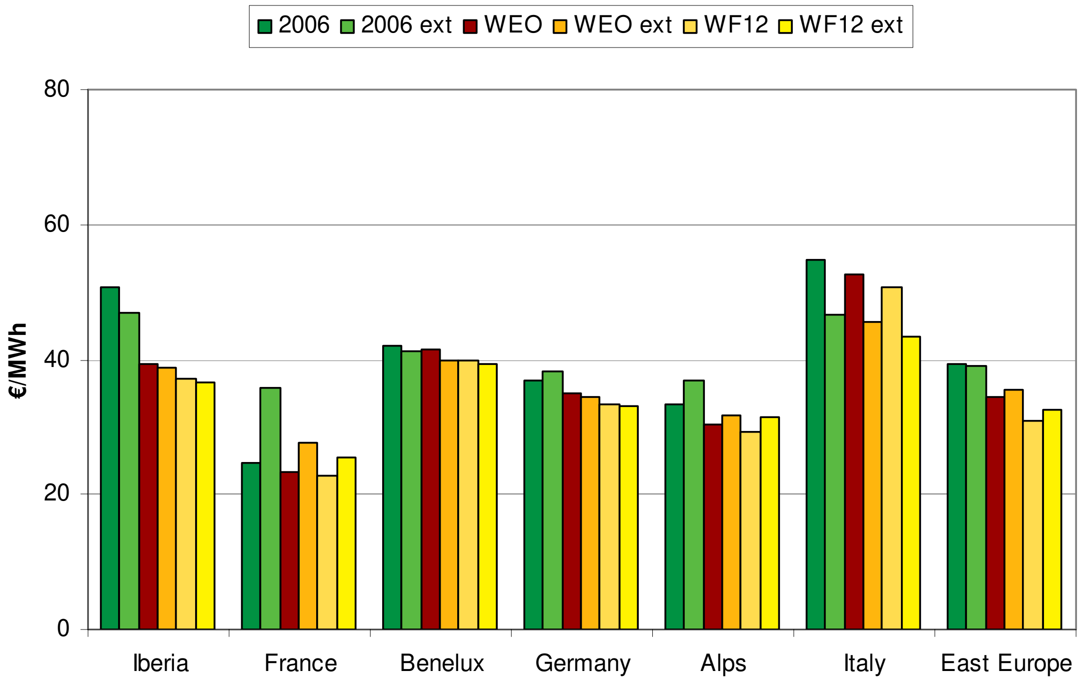
First, we present the results assuming an average emission allowance price of 20 €/EUA. Given the modeled situation of 2006 we observe an intermediate price level in Central and Eastern Europe, low prices in France due to the large share of nuclear generation, and high prices in Italy and the Iberian Peninsula. If the grid is extended we observe a general price convergence in Europe. However, now the low-price regions encounter higher prices, which is particularly striking for France (Figure 1). The first extension scenario WEO results in lower prices in Europe compared to 2006. On average the projected 115 GW wind capacities have a positive effect on electricity prices. We observe the highest benefit in the Spanish and Portuguese markets. After the grid extension we again observe a price convergence within Europe, although the price level in Italy stays higher. The same is true for the

WF12 scenario. We observe a small further price decrease compared to the WEO case and a price convergence in Central Europe.

Second, we analyze the price developments, given a high price for emission allowances of 50 €/EUA. Starting with the modeled situation in 2006 we observe a similar price pattern as in the 20 €/EUA case. However, the absolute price level is about 10 to 20 €/MWh higher, corresponding to the increase in generation costs. After the grid extension the prices tend towards a more common level in Europe, although regional differences remain. In the two wind extension scenarios the price level further decreases particularly in Spain and Portugal, with a reduction of about 20 €/MWh. Also in East Europe a significant reduction is observable (Figure 2). The extended grid results are quite similar to the case with the lower emission price leading to further reduced prices in southern Europe and a more equalized price level in central Europe.

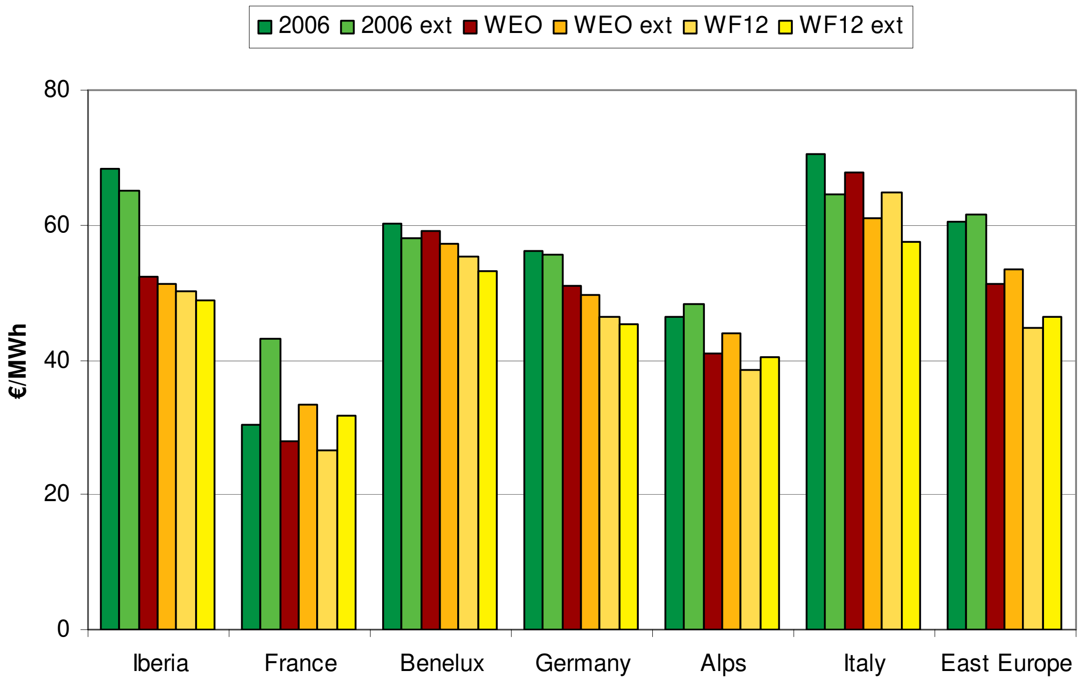
Given the price developments we can conclude that an increase of installed wind capacity in the years ahead leads to electricity price reductions as wind partially replaces conventional generation. This is of particular concern in Spain and Portugal where a doubling of the current installed wind capacity significantly reduced prices. We note that the benefits of increased wind are less striking in the remaining countries. However, grid expansion will not lead to a reduced price level in all European countries. The present situation is characterized by congestion at the borders and a market separated into several price zones. If increased network capacity removes some bottlenecks and brings prices closer together, formerly low-price regions (e.g., France) will likely encounter higher prices.

Figure 1: Average prices before and after the network extension, 20 €/EUA



Source: Own calculations.

Figure 2: Average prices before and after the network extension, 50 €/EUA



Source: Own calculations.

4.2 Comparison

The results of the scenario runs are presented in Table 4. We observe that the extension of wind capacities leads to a lower average electricity price. In the case of an average emission allowance price the reduction is about 5 to 8 €/MWh, depending on the installed wind capacity. If we assume a higher emission price, the positive price impact of wind increases to 18 and 22 €/MWh. However, as already noted, this does not mean that each region profits from increased wind input in a similar fashion.

One surprising outcome is that the benchmark model shows the highest amount of grid extension for both CO_2 price scenarios. One would expect that the increased wind capacities in 2020 lead to a greater need for grid extensions due to an increase in the transmission volume and unintended loop flows. However, given the model setting, we find the opposite. The current grid conditions already show a high level of congestion which makes an ambitious extension schedule necessary. The increase in future wind generation appears to support the overall power flow pattern. This may stem from the fact that in 2006 wind capacity clusters in Germany, Denmark, and Spain, whereas in the two 2020 scenarios France, Italy and Poland have significant installed wind capacity. Accordingly, the need for transporting wind might decrease. The model does not differentiate for wind speeds. Thus for the high wind input cases, wind generation is increased equally in all countries, leading to the possibility of counter injections (e.g., between France and Germany) reducing actual load. However, this benefit depends on the amount of wind capacity installed. In the WF12 scenario the total grid extension is similar to the benchmark case, while in the WEO scenario the amount is significantly lower. We note, therefore, that the positive effect of opposing wind injections may be offset by localized problems in the case of the large capacity increase in the WF12 scenario.

The welfare properties of the extensions are generally positive in all cases. Given the relatively low extension costs of about 500 million Euro (less than 0.5% of the total welfare) a significant welfare increase of more than 2.5 billion Euro per year is obtainable. Furthermore, a large fraction of this welfare gain is already achieved by the first extensions. In the benchmark case with 20 €/EUA, a welfare gain of 1 billion Euro is already achieved after 20 line extensions totalling less than 50 million Euro. The relatively low investment costs are a result of the model restriction to line upgrades and the assumption that each line can be upgraded to four circuits which may not always be feasible.

Another remarkable outcome is that in the case of higher emission allowance prices, the grid extension is lower. Given the higher costs for conventional power plants we would assume that an increase of wind reduces the need for expensive fossil fuels and thus increases the welfare gain by wind integration. Altogether, the resulting prices are higher because of the more expensive fossil plants that in turn lead to a lower demand in the entire system given the modelled linear demand function. Thus, there are less extension requirements as the transmission volume decreases. The important number in the high CO_2 price case is the welfare gain induced by grid extensions. Table 4 shows that the gain is higher as the price difference between the costs of wind energy and fossil production increase.

Our approach calculates the weighted average of four representative hours. The separated observation of one worst-case hour with very strong wind (all wind generation capacities produce maximum power) may lead to collapse even with grid expansion. Because this situation will occur rarely (less than 2 to 4% of time on average), economic considerations tend to accept this "threat" since the additional investment costs are not justified. Such extreme events should be managed with technical measures other than line upgrades, such as active wind farm management, extensive grid monitoring, etc.

Table 4: Results overview

CO_2 price:	**20€/EUA**			**50€/EUA**		
Scenario	**Bench mark**	**WEO**	**WF12**	**Bench mark**	**WEO**	**WF12**
Wind capacity [GW]	43.9	114.5	181.0	43.9	114.5	181.0
Upgraded circuits	159	139	138	124	100	116
Total length [km]	6220	5330	6440	5200	4500	5300
Additional line capacity [GW]	143	106	114	102	85	92
Total costs [mn €]	580	475	560	460	400	445
Average price [€/MWh]	40.1	34.6	32.7	65.2	47.0	43.4
Welfare [bn €/a]	230	238	242	218	229	235
Welfare gain due to extension [bn €/a]	2.9	2.6	2.9	3.9	3.2	3.9

Source: Own calculations.

5 Conclusion

From the perspective of economics, this paper shows that efforts to prepare Europe's high voltage grid for large amounts of wind generation appear to be rather modest. Developing the network at existing bottlenecks – mainly cross-border connections –should be encouraged by regulatory authorities. With a more moderate wind expansion of 114.5 GW, the optimal grid investments are smaller. However, if the additional wind capacity becomes too great (181 GW), the needed grid extensions will increase compared to the actual situation. "Greening the grid", i.e. enabling the integration of low-carbon technologies, appears feasible for wind energy. Further research should address issues of stochasticity, and apply similar analysis to other renewables, e.g., solarthermal and photovoltaic. A study of the transferability between Europe and U.S. experiences also appears fruitful. We suggest that other research might examine the relationship between fostering renewable energy production and the design of efficient contract networks, e.g., resolving issues of priority network access for renewables and transmission rights.

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