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Chair of Energy Economics and Public Sector Management

Nodal Pricing of the European Electricity Grid - A Welfare Economic Analysis for Feeding-in Offshore Wind Electricity

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Abstract:

In this paper, we apply the theory of nodal pricing to a particularly urgent issue of energy and environmental economics: the integration of wind power in electricity systems. We use a nodal pricing model to analyze the impact of German wind power production on the North Western European power grid. Especially the Benelux countries are supposed to suffer from congestion due to unintended, yet inevitable cross-border power flows. The paper shows that economic modelling, taking into account physical and technical constraints, makes important contributions to the assessment and optimization of system configuration and operation.

Key words: electricity networks, nodal pricing, welfare, wind energy
JEL-code: L94, L51, D61

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Abbreviations

AC	alternating current
DC	direct current
DCLF	DC Load Flow model
DENA	Deutsche Energie-Agentur (“German Energy Agency”)
kV	kilovolts
MW	megawatts
MWh	megawatt hours
P	real power
Q	reactive power

Nomenclature

Symbols:

B	line series susceptance [1/Ω]
C	total costs of production [€]
d_n	demand at node n [MWh]
d_n^{ref}	reference demand at node n [MWh]
d^*	equilibrium demand [MWh]
d_n^*	equilibrium demand at node n [MWh]
G	line series conductance [1/Ω]
g_n	generation at node n [MW]
g_n^t	generation of plants of type t at node n (*) [MW]
$g_n^{t,max}$	maximum generation capacity of plants of type t at node n [MW]
L_{jk}	losses of real power [MW]
P_{jk}	real power flow between two nodes [MW]
P_i	real power flow at line i [MW]
P_i^{max}	transmission capacity constraint at line i [MW]
p_{ref}	reference price [€/MWh]
p^*	equilibrium price [€/MWh]
p_n^*	nodal price at node n [€/MWh]
p_u	uniform price [€/MWh]
R_i	line resistance [Ω]
$V_{j,k}$	voltage magnitude at a node [volts]
W	welfare [€]
X_i	line reactance [Ω]
X_m	line reactance for m circuits [Ω/km]
$\delta_{j,k}$	voltage angle at a node [rad]
ε	demand elasticity at reference demand
Θ_{jk}	voltage angle difference [rad]

Indices:

i	line between node j and node k
j	node within the network
k	node within the network
m	number of circuits
max	maximum
n	nodes within the network
ref	reference
t	type of generation plant

1 Introduction

With the fast extension of wind capacities especially in Northern Germany congestion management has become a serious issue in the North-Western European electricity grid. Due to power distribution through the entire European integrated network (UCTE grid) according to relative line impedances, Germany's neighbors to the North West, namely Benelux countries, are affected by unintended but inevitable cross border flows congesting their grids. With the intended expansion of offshore wind capacities in the German North Sea, this problem is bound to aggravate.

In this paper we assess the impact of German wind capacities on the Benelux using a nodal pricing approach. In recent years nodal pricing has developed from a mere theoretical approach to an efficient practical tool of transmission pricing and congestion management. Experiences in North America, namely PJM, Australia and the recent implementation in the UK have proven nodal pricing to be workable in large electricity networks. Instead of technical parameters, nodal pricing indicates congestion through price signals. Thus the impact of additional wind energy can be estimated by analyzing the price situations.

We present a model for nodal pricing in the electricity sectors of Germany and its neighboring states. We carry out a welfare-economic analysis, focusing particularly on the effects of implementing large-scale offshore wind power on the German and Benelux country power grids. We want to demonstrate how unintended cross border flows increasingly congest the North-Western Europe grid with growing German off shore capacity. Our hypothesis is that wind capacities cause congestion affecting the Benelux grid and therefore lead to price increases in times of high wind input. Additional wind capacities, especially offshore, will aggravate the situation.

The paper is structured in the following way: The next section provides an overview of the literature on nodal pricing and on congestion management in general. Section 3 describes the model and data that we use. We implement the DC load flow model as proposed by Schweppe, et al. (1988) and Todem and Stigler (2005), for the North West European high voltage network topology (including voltage levels from 380 kV down to 150 kV) and a data set on power generation and demand in the participating countries. Section 4 gives an overview of the scenarios that we compare: First nodal pricing is compared to uniform pricing and the impacts of cross border flows are examined for the German grid. Second the impact of wind energy on the Benelux grid is analyzed. After modeling the current situation, a future scenario with extended onshore capacities and 9.8GW offshore capacities is simulated. Moreover, the interdependence of Northern wind and Southern water energy is examined. Section 5 then provides the results of the scenarios and their interpretation. We find that nodal pricing is superior to uniform pricing and the neglect of cross border flows leads to distorted price estimation in certain parts of Germany. We conclude that in times of high wind input Belgium faces slightly higher nodal prices under present conditions. The planned extension of wind capacities in Germany will lead to price increases in the North of the Netherlands, if the grid is not properly extended. Furthermore we find that the price impact of wind and water energy is rather local. Note that the calculations are taken out for reference hours therefore neglecting time restrictions like start up times of fossil plants. Also reserve problems and reactive power issues are not considered.

2 Literature Review

The recent study from the German Energy Agency (DENA 2005a) analyzed the costs of integrating additional wind capacities in the German grid. Particularly the grid extensions due to emerging network bottlenecks would be cost-intensive. Leuthold et al. (2005) take up this problem and analyze the impact of additional offshore capacities when using a nodal pricing mechanism instead of the current uniform pricing in Germany. They conclude that when using nodal pricing additional 8 GW offshore wind capacities can be implemented without grid extension. The model neglects cross border flows and therefore the impact of German wind energy on the grid of neighboring countries.

Congestion management, in particular at the European level has become a relevant topic since liberalization of electricity markets is in progress. Boucher and Smeers (2001) analyzed the future organization of cross border trade in the European electricity market concluding that the economic principles as proposed by the European Commission in 2001 are not sufficient. Ehrenmann and Smeers (2004) analyze the regulation of cross border trade of electricity (Regulation 1228/2003) in terms of efficient congestion management. They conclude that market coupling - although its implementation is more complex - can path the way to a consistent system integrating the energy and transmission markets. Arriaga and Omos (2004) analyzed plausible congestion management schemes for the internal electricity market of the European Union. Taking a joint energy and capacity auction as benchmark they test two alternative approaches, an integrated transmission and energy auction and a coordinated explicit auction of transmission capacity followed by separate energy auctions at the different power exchanges. The authors propose the latter since it is relatively close to the actual market structures.

Most European national markets are based on a domestic uniform pricing mechanism. Cross border transactions are carried out by separated auction mechanisms. Uniform pricing has the drawback that it works efficiently only in the absence of congestion. In the case of congestion it does not send adequate market signals as do nodal prices. Therefore uniform pricing is not able to ensure an optimal allocation of electricity and of transmission capacities in a situation of congestion (see Hogan, 1999, and Krause, 2005). Xingwang et al (2003) sum up this problem as the incapability of uniform pricing to achieve harmony between market liquidity and efficient pricing.

One attempt to solve incentive problems of the uniform pricing approach was to introduce zonal pricing, which is currently applied in Norway (since 1991), Australia (since 1998), and Denmark (since 2000). The California ISO used zonal pricing from 1998 to 2002 (Ding and Fuller, 2005). According to this approach, the market is divided into several zones depending on their respective congestion costs. Purchala et al (2005) discuss the feasibility of a zonal network model of the UCTE for congestion management purposes. By aggregating all nodes within a country to one node and substituting all cross border lines into equivalent border links the impact of zonal cross border exchanges on particular borders in the interconnected network can be estimated. They conclude that the accuracy of the model is sufficient for a broad number of scenarios. Krause (2005, p. 34) also claims the zonal pricing systems in Australia and Norway to work well (also see Johnsen et al, 1999, p. 1). However, Hogan (1999) rejects the model of zonal prices for a number of reasons, mainly due to the fact that it is "[…] an effort to treat fundamentally different locations as though they where the same […]" (p. 1). In addition, Alaywan and Wu (2004, p. 1), claim that the zonal market design of California had contributed to the energy crisis in 2000 and 2001.

A nodal price spot market with bid-based, security-constrained, economic dispatch as proposed by Hogan (2003, p. 2) reflects the actual situation in a grid more transparently than power markets based on uniform or zonal pricing and separated auction mechanisms for cross border trade. Nodal prices represent adequate allocation signals and are one of several important considerations in analyzing where to locate additional generation, transmission and load. The implementation of efficient congestion management methods on the basis of nodal pricing is crucial in coping with scarce transmission capacities and ensuring security of supply. This approach may also save costly investments in transmission lines (see Bower, 2004). Nodal pricing has emerged from a theoretical approach to an efficient tool of transmission pricing. It is implemented in New Zealand, parts of North America and has recently been introduced in the UK. Other markets like California are planning to introduce nodal pricing in the coming years.

Green (2004) shows that the introduction of a nodal pricing concept in England and Wales would raise welfare by 1.5% compared to the uniform model. For the Austrian high voltage grid, Stigler and Todem (2005) have analyzed the economic impact of a nodal price based congestion management. They suggest a division of the network into two pricing zones according to their congestion situation. The most efficient solution to overcome the congestion problem would be to build an additional 380-kV line – the so called 'Steiermark'-line. Leuthold et al. (2005) calculated a social welfare increase of about 1 % in a nodal pricing system for Germany, as compared to uniform pricing. Another 1,8% of additional welfare would result from increased use of offshore wind energy. Our study is the first approach to model the effects of nodal pricing in combination with increased wind energy on the North-Western European grid.

3 Model and Data[c]

3.1 Optimization problem

The optimization for all scenarios is based on a social welfare approach. In our partial equilibrium approach, welfare equals total consumer benefit minus the cost of generation needed to satisfy demand, which is identical to the sum of consumer and producer surplus. Optimal dispatch is determined respecting physical laws[d] and technical conditions, namely the energy balance and capacity constraints of lines and power plants:

$$\max \; W = \sum_n \left(\int_0^{d_n^*} p(d_n)\, \boldsymbol{d}d_n - \int_0^{d_n^*} c(d_n)\, \boldsymbol{d}d_n \right) \tag{1}$$

s.t.

$$\left|P_i\right| \le P_i^{\max} \qquad \text{line flow constraint} \tag{2}$$

$$\sum_n g_n = \sum_n d_n + L \qquad \text{energy balance constraint} \tag{3}$$

$$g_n^t \le g_n^{t,\max} \qquad \text{generation constraint (per type of plant)} \tag{4}$$

Total costs include only marginal costs of generation. Additional costs, e.g. those arising from network operation and maintenance, are not considered. Having the optimal dispatch for every node d_n^*, the corresponding market clearing nodal price p_n can be obtained from the inverse demand function:

$$p_n = p_n^{ref} + \frac{1}{\varepsilon} \cdot p_n^{ref} \cdot \left(\frac{d_n^*}{d_n^{ref}} - 1 \right) \tag{5}$$

In the case of a uniform pricing mechanism an additional constraint has to be considered in the optimization approach assuring price equality in each country respectively:

$$p_n - p_u = 0 \qquad \text{price equality constraint} \tag{6}$$

[c] This and the subsequent sections draw heavily on Leuthold et al. (2005)
[d] Namely Kirchhoff's laws and power distribution according to relative line impedances. Different outgoing lines act as current divider. For further information see relevant technical literature, e.g. Lunze (1987), Stoft (2002).

The optimization is carried out in GAMS. Power flows are obtained using the DC load flow model. The reference period referred to is one hour. Since the approach is time static, different scenarios are calculated to simulate changing external conditions. To take into account the (N-1)-constraint a transmission reliability margin of 20% is used, thus each line can be stressed up to 80% of its thermal limit.

3.2 The DC Load Flow Model

Calculations in electricity networks are highly complex due to the general characteristic of power flows in meshed networks and especially the occurrence of reactive power[e]. The DC Load Flow Model (DCLF) simplifies the modeling of electricity networks in case of symmetrical steady states. The DCLF focuses on real power flows, neglecting relevant reactive power issues[f]. Schweppe *et al* (1988) showed that the DCLF can be used as an instrument for an economic analysis of electricity networks particularly with regard to the fact that the main purpose of electricity networks is the transport of real power (Todem et al, 2005, p. 5). Overbye et al (2004) compared the DCLF with an AC model concluding that for the calculation of nodal prices the DCLF is adequate. Only in cases of high reactive and low real power flows the difference is significant (Overbye et al, 2004, p. 4).

Based on the assumption that real power P flows according to the differences of the voltage angles (Θ_{jk}) between two nodes, one can model the real power flow by focusing only on voltage angle differences. The paper of Stigler and Todem (2005, pp. 114-115) explains the basic equations that are described by Schweppe et al in detail[g]:

$$P_{jk} = G_i \left|\underline{V}_j\right|^2 - G_i \left|\underline{V}_j\right| \left|\underline{V}_k\right| \cdot \cos\Theta_{jk} + B_i \left|\underline{V}_j\right| \left|\underline{V}_k\right| \cdot \sin\Theta_{jk} \tag{7}$$

$$\Theta_{jk} = \delta_j - \delta_k \tag{8}$$

$$B_i = \frac{X_i}{X_i^2 + R_i^2} \tag{9}$$

$$G_i = \frac{R_i}{X_i^2 + R_i^2} \tag{10}$$

Equation (7) is the basis for all further calculations. Moreover, two basic assumptions must be made (Schweppe, 1988, p. 314):

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[e] Since the reactance changes with changing power flows the grid topology has to be adjusted according to the actual line flows.
[f] The necessity or influence e.g. of investments in compensation facilities cannot be modeled considering DC flows only.
[g] For a more detailed explanation of the DCLF please refer to Schweppe et al (1988) and Todem et al (2005).

1. The voltage angle difference Θ_{jk} is very small, hence one can assume that $\cos\Theta_{jk} \approx 1$ and $\sin\Theta_{jk} \approx \Theta_{jk}$.
2. The voltage magnitudes $\underline{V}$ are standardized to per unit calculation. Hence, they can be considered to be equally one at each node ($\underline{V}_j \approx \underline{V}_k$).

This yields a linear equation for the lossless line flows:

$$P_{jk} = B_i \cdot \Theta_{jk} \tag{11}$$

The second step is the estimation of losses occurring along the line. Losses are important as they cause the sum of generation not to equal the sum of demand. Thus, transmission lines are stressed by demand plus losses[h]:

$$L_{jk} = R_i \cdot P_{jk}^2 \tag{12}$$

Based on equations (11) and (12), the real power flow within an electricity grid can be calculated and the impact of changing demand and generation examined, thus forming the framework for the calculation of the necessary technical constraints (2), (3) and (4).

3.3 Data

The model is based on the UCTE extra high voltage grid (UCTE, 2004) of Denmark, Germany, the Netherlands, Belgium, Luxemburg, France, Switzerland and Austria. The basic model consists of 1270 substations (nodes) and 1844 lines. Three voltage levels are considered, 380kV, 220kV and 150kV. Two variations of this network are used, a slightly extended grid with 12 additional lines[i] and a reduced version consisting only of the German grid.

Three line parameters are needed for the DCLF: thermal limit, line resistance and line reactance. For each voltage level a reference line type was chosen, thus neglecting impacts of the wide range of different lines. For 380kV four cables per wire, for 220kV two cables per wire and one cable for 150kV were assumed. The thermal limit[j] is 1700MVA for 380kV, 490MVA for 220kV and 140MVA for 150kV (Fischer, Kießling, 1989, p. 2). In our model these maximal allowable power flows are multiplied by two when using a double circuit and are three times larger in case of a triple circuit. In addition, we assume that each line can only be stressed to 80% of the given values because of the

[h] For an explanation how to obtain losses in a DCLF please refer to Schweppe et al (1988) and Todem et al (2005).
[i] For a detailed overview about the gird extensions see Annex 1.
[j] Values are for apparent power *S*.

reliability margin. Realistic values for the resistance and reactance of high voltage circuits are subject to empirical experience. Fischer and Kießling (1989, p. 2) give a satisfactory approximation for reliable values (Table 1).

Number of circuits	**Voltage level [kV]**	**Resistance [Ω/km]**	**Reactance [Ω/km]**
Single circuit (in a double circuit system)	380	0.030	0.26
	220	0.059	0.32
	150	0.100	0.38

Table 1: Values for reactance and resistance

Source: Fischer and Kießling (1989, p. 2).

Generation capacities are based on VGE (2004). Eight types of conventional power plants are classified and each plant was assigned to one class according to the main fuel type (Table 2). Wind capacity information is based on several sources. For Germany, a map of the distribution of wind energy capacities (ISET, IWET 2002) was used to obtain a pro rata distribution for the nodes in each federal state. Based on the report of the German Wind Energy Association on installed wind energy capacity (DEWI, 2005) actual values for the installed capacities at each node are calculated. For other countries the wind capacity distribution is based on the available information, mainly on state base[k].

Fuel	**Installed capacity [GW]**	**Fuel**	**Installed capacity [GW]**
Coal	57.4	Natural gas	25.5
Lignite	22.3	Fuel oil	22.4
Nuclear Power	89.6	Water	29.6
CCGT	10.9	Pump storage	12.1
Wind	21.8	***Total***	***291,4***

Table 2: Power plant capacities

Source: VGE (2004), own calculations.

3.3.1 Generation costs

The node specific generation costs are calculated on a marginal cost basis, including fuel costs, but not accounting for operating and service costs. Wind power generation costs are based on an estimation of impacts on the power plant fleet, mainly from balancing and response power costs. Since these types of costs are not considered in the model itself they have to be taken into account over the price for wind energy according to cost estimations in the DENA study (DENA, 2005b, p. 14). Pump storage is

[k] EMD (2005), EWEA (2005), IG Windkraft (2005), Wind Service Holland (2005)

assumed to store in the night hours (8p.m. to 8a.m.) by purchasing electricity on the stock exchange. The average price during the night time in 2003 is about 21€ for all relevant European power exchanges[1]. Assuming an efficiency of 75%, the marginal cost for pump storage amount to 28€/MWh. Marginal costs of conventional plant types were taken from Schröter (2004, p. 7).

Fuel	**Marginal costs [€/MWh]**	**Fuel**	**Marginal costs [€/MWh]**
Nuclear Power	10.00	Natural Gas	40.00
Lignite	15.00	Fuel oil	50.00
Coal	18.00	Running water	0.00
CCGT	30.00	Pump storage	28.00
Wind	4.05		

Table 3: Marginal costs of power generation per fuel

Source: DENA (2005a), Schröter (2004), own calculation.

3.3.2 Demand

To obtain a node specific reference demand, the regional GDP (Eurostat, 2005) was used to obtain a regional demand for electricity. 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 was divided according to the GDP proportions. Within a province, the demand was distributed equally over all nodes.

4 Scenarios, Results, and Interpretation

4.1 Scenarios

Three thematic scenarios were considered:

1. *Importance of cross border flows:* Since load flows follow physical instead of geographical or economic laws, the grid topology has an important impact on the obtained results. First, an welfare analysis based on the German grid is carried out and then compared to the results obtained when including neighboring countries.
2. *Impact of German wind on the Benelux:* German wind capacities are mainly located in the North and therefore lead to unwanted cross border flows into the Benelux grid. The impact on the price situation in the Benelux is analyzed based on the actual grid situation as well as on

[1] Spot market prices at APX, EEX, EXAA and PNX.

an approximated situation with increased on- and offshore wind capacities based on estimations for 2015.

3. *Interdependence of wind and water energy:* Wind and water energy are the cheapest energy sources in terms of marginal costs and both depend on external conditions. To estimate the price impact scenarios with high and low wind or water input were calculated.

4.2 Results and interpretation

4.2.1 Importance of cross border flows

We compute two possible price cases for each of the scenarios: uniform pricing and nodal pricing. As theory suggests, we always expect nodal pricing to be superior to uniform pricing in terms of efficiency, thus welfare. The analysis is first carried out for the German grid without neighboring countries, therefore neglecting cross border flows. In a second step, the grid is extended, now including Denmark, the Benelux, France and the Alpine countries Switzerland and Austria, to estimate the impact on the price situation in Germany. We expect that prices will differ for both cases since the neglecting of cross border flows disregards the opportunity of electricity import and export as wells as the impact of congestion in neighboring countries on the German grid.

All calculations are based on the existing grid and average 2003 demand. The reference price for each country is obtained by calculating the average price in 2003 – the same as for demand calculation – on the power exchange markets[m]. Wind input and availability of water capacities are set to values based on average full load hours.

Topology:	**Segregate German grid[n]**		**German grid and neighboring grids[o]**	
Pricing mechanism:	**Uniform**	**Nodal**	**Uniform**	**Nodal**
Welfare [Mio €]	4.411	4.413	11.50	11.59
Demand [GWh]	62.85	62.95	146.99	154.76
Generation [GWh]	63.62	63.65	148.95	157.06
Losses [GWh]	0.77	0.69	1.97	2.30
Average Generation Costs [€/MWh]	13.20	13.17	10.92	10.84

Table 4: Results for the impact of cross border flows

The results show that social welfare under nodal pricing is higher than under uniform pricing. Also the impact is rather small in the segregate German grid, whereas the surplus in a grid covering eight

[m] APX for the Netherlands, EEX for Germany, EXAA for Austria, Nordpool for Denmark, PNX for France and an average value of 30€/MWh for all countries without a power exchange.
[n] Hourly values, results refer to Germany alone
[o] Hourly values, results refer to all investigated countries

countries is noteworthy. A social welfare gain of 0.8% under average conditions is possible simply by implementing a nodal pricing mechanism in the investigated countries. Also a demand increase and a cost decrease can be observed (Table 4).

The uniform price in the segregate German grid is about 19.7€/MWh while the average nodal price is 19.1€/MWh. However prices in Southern Germany are higher under nodal pricing whereas prices in Northern and East Germany are lower. To estimate the impact of cross border flows these prices were compared to prices obtained in the grid covering all eight countries. The results clearly show that neglecting cross border flows leads to an overestimation of prices in Southern and Western Germany, mainly in Baden-Wuerttemberg and Bavaria (Figure 1). This is caused by the missing opportunity to import electricity from France, Switzerland and Austria. On the other hand prices in North-West Germany are slightly underestimated. This is caused by congestion in the Dutch grid limiting the amount of electricity that can be transported within North-West Germany. Even under a uniform pricing regime the integration of neighboring grids leads to a noticeable price reduction to 17.8€/MWh, which is a reduction of 10% compared to the situation in the segregate German grid.

Altogether the importance of cross border flows - namely the opportunity to import electricity and the impact of congestion in neighboring countries - is well illustrated. Furthermore, the hypothesis that nodal pricing is superior to uniform pricing can be affirmed.

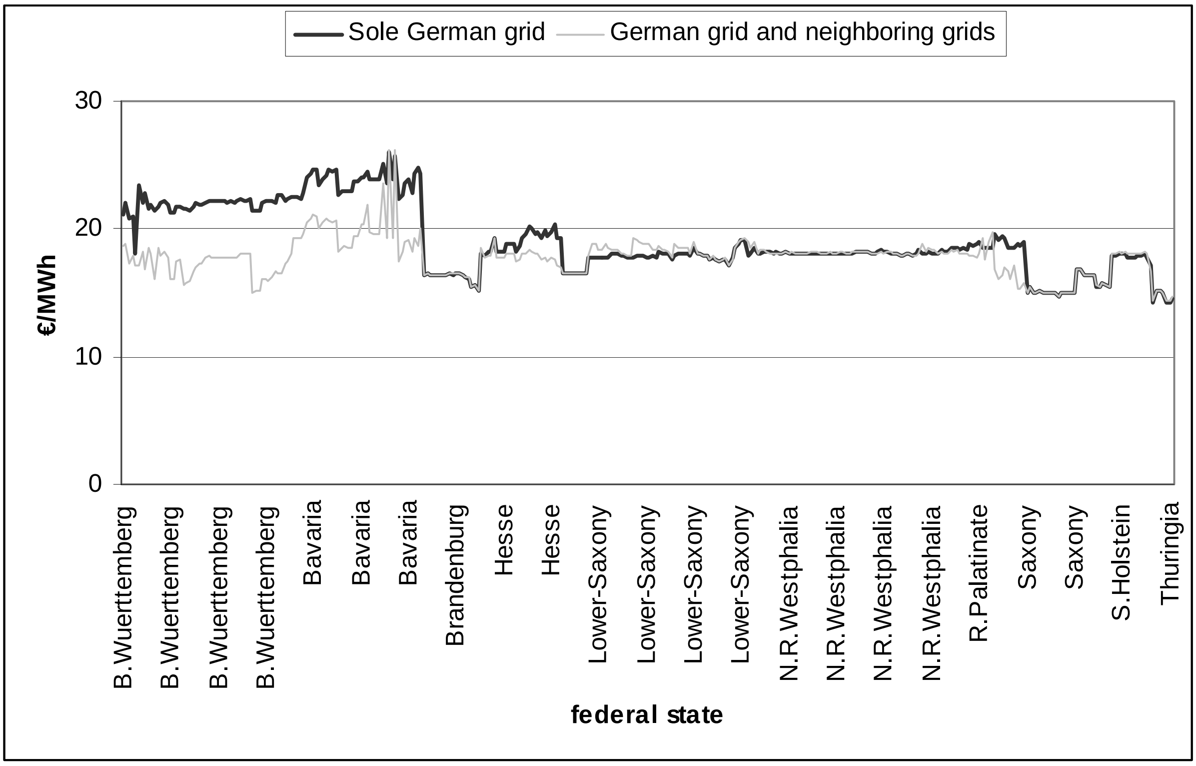

Figure 1: Comparison of nodal prices in Germany

4.2.2 Impact of German wind on the Benelux countries

In a next step the situation in the Benelux is analyzed. We want to find out if the German wind capacities lead to additional congestion and therefore to a price increase in the Benelux. Since power flows according to relative line impedances, additional wind energy can cause unintended but inevitable cross border flows, thus causing congestion. A nodal pricing mechanism is supposed to reflect congestion via price increases and price differences between nodes.

First, the existing grid is analyzed. Based on the same average assumptions for water availability, demand and reference prices as in the first scenario, a simulation for low and high wind input is carried out. In a second step, the grid is extended and additional wind capacities are installed to estimate the impact of the ambitious German offshore objectives. The grid extensions[p] are based on the annual reports of the system operators[q] as well as VGE (2004). This can be considered as the minimum extensions to come. The wind capacities are increased according to EWEA (2003) and DENA (2005). Since all assumptions for the fossil power plant mix, the demand and price situation are held equal to the first scenario, the analysis can be considered as an estimation of increased wind input in the actual grid situation and not as a future scenario for 2015. The aim is to find out if the existing grid (with already planned extension) can handle an increased wind input, especially at the German coast line, and what impact on the Benelux can be expected. The calculation is again carried out for a low wind input scenario and a high wind input scenario. Note that wind energy has a feed-in guarantee in the model. All calculations are based on a nodal pricing mechanism.

Topology:	**Existing grid**		**Extended grid**	
Wind input:	**Low**	**High**	**low**	**high**
Welfare [Mio €]	11.53	11.76	11.63	11.95
Demand [GWh]	154.6	155.0	154.1	158.7
Generation [GWh]	157.0	157.2	156.7	161.2
Losses [GWh]	2.34	2.13	2.52	2.49
Average Generation Costs [€/MWh]	11.22	9.74	10.50	7.91

Table 5: Results for the impact of German wind on the Benelux

The analysis shows a welfare gain in cases of high wind input for both the existing grid and the extended grid. This goes along with increased demand, reduced losses and reduced costs. Note that these results are calculated for the whole system and not separately for the Benelux. Also, an

[p] For a detailed overview about the gird extensions see Annex 1
[q] Elia 2004, for Belgium; Tennet 2004 for the Netherlands; APG 2005, for Austria

additional welfare increase of 0.9% in times of low wind input and 1.6% in times of high wind input can be obtained by increasing offshore and onshore wind capacities.

The comparison of prices in the Benelux shows no price spikes caused by high wind input in the existing grid (Figure 2). In fact, the price level in the Netherlands is lower in periods of high wind input because more local wind energy is available in the North and the area of Amsterdam. However, the Belgian consumers have to face slightly higher prices caused by the changed grid conditions. Although more energy is available in times of high wind input, the increased power flows from areas with large wind capacities cause a changed congestion situation resulting in price increases in certain areas. Also a clear price difference between the area of Amsterdam and the rest of the Netherlands can be observed, both in time of low and high wind input, indicating a general need for grid extension[r].

The extension of both grid and wind capacities yields different results. The already planned grid extensions[s] relax the situation at the French-Belgian border and lead to price reductions in Belgium. In case of high wind input - including 9.8 GW offshore in Germany - prices in Belgium will drop compared to the actual situation while in the Northern parts of the Netherlands a notable price increase occurs (Figure 3). This is caused by congestion at the Dutch-German border due to high wind energy supply in Northern Germany. Although the results differ, the impact of North-Western European wind capacities is obvious. In both the existing and the extended grid price increases in times of high wind input are observable.

In Northern Germany we even observe negative prices at certain nodes in the extended grid scenario. This is caused by the feed-in guarantee for wind energy. Since the grid is not capable of transporting the increased amount of wind energy, demand at the feed-in nodes has to increase until all wind energy is consumed. Note that the extended grid only includes minimal grid extension and the expected wind capacities in 2015 while demand, price and fossil capacities remain at actual values. The results therefore represent the need for grid extensions to prevent additional congestion.

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[r] Which is currently underway.
[s] Namely the upgrade of the 300kV line between Avelin and Avelgem to a double circuit system and the planned line between Aubange and Moulaine.

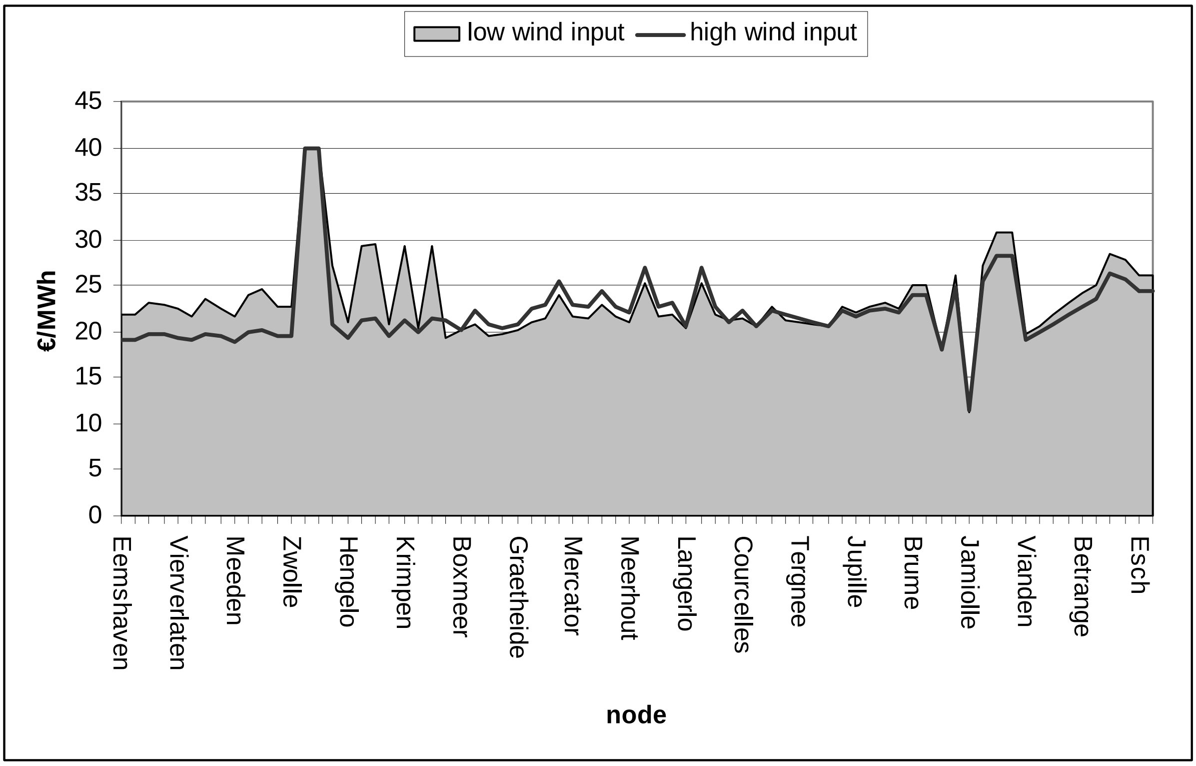

Figure 2: Comparison of nodal prices in the Benelux in the existing grid

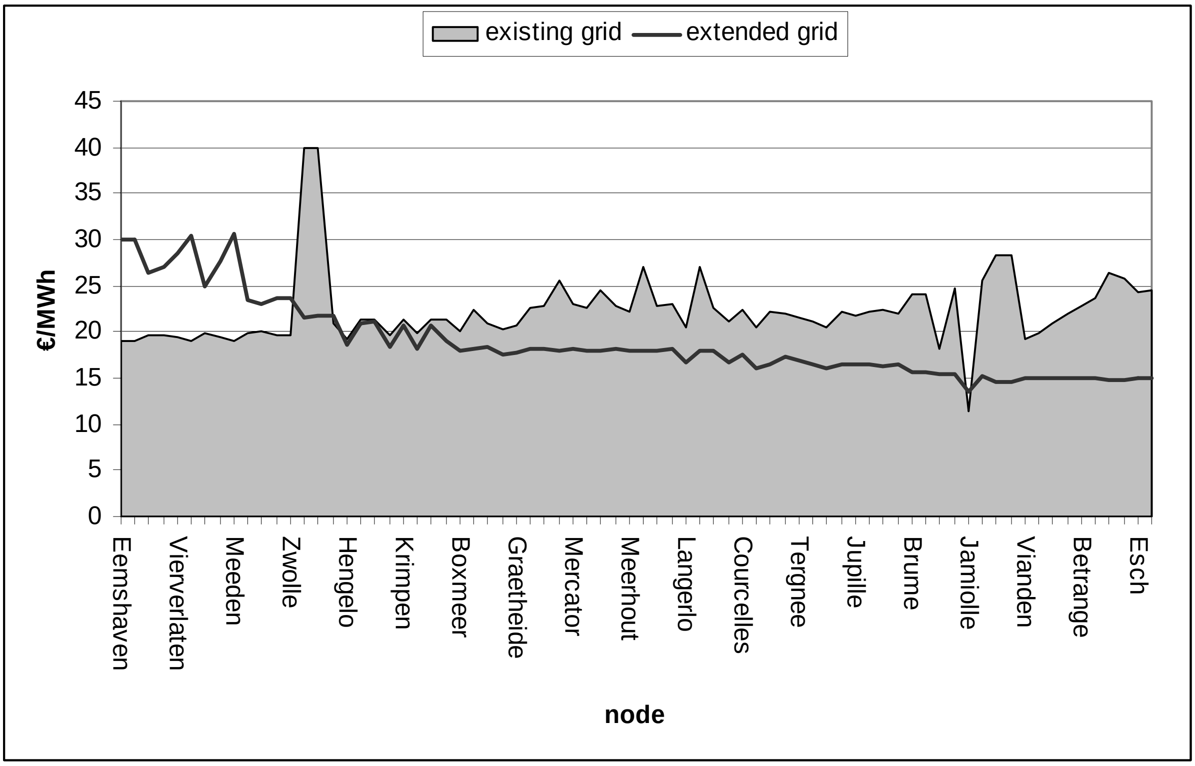

Figure 3: Comparison of nodal prices in the Benelux with high wind input

4.2.3 Interdependence of wind and water energy

In a third scenario the impact of both water and wind energy on nodal prices is investigated. Power generation from wind and water are both cheap in terms of marginal costs and both depend on external conditions. While water generation is concentrated in mountain areas, wind energy is concentrated at coast lines. Our aim is to find out how prices react to the availability of wind and water energy and to what extent these effects remain local. Our hypothesis is that because of congestion the price reducing effects of wind and water are limited to local points, leading to increased price differences in the system. In contrast to the other two scenarios a peak demand situation is assumed. Because of increased line flows as well as a higher price level local effects should be easier to detect. Reference demand is 30% higher than in the average scenarios and the reference price is based on the average price during daytime[t] in 2003. The calculations are carried out for high and low wind input and water availability respectively, resulting in four cases. Again all calculations are based on a nodal pricing mechanism.

Water availability:	**low**		**High**	
Wind input:	**Low**	**high**	**low**	**High**
Welfare [Mio €]	17.99	18.36	18.35	18.70
Demand [GWh]	18.89	19.24	19.30	19.79
Generation [GWh]	19.05	19.50	19.53	20.07
Losses [GWh]	1.63	2.54	2.19	2.81
Average Generation Costs [€/MWh]	13.93	12.25	12.30	10.85

Table 6: Results for the interdependence of wind and water energy

The results show a welfare increase with increased input of low-cost wind and water energy (Table 6). The comparison of an hour with low wind input and reduced water availability with the respective counterpart yields a welfare increase of 4%. The results for high wind input and low water availability and vice versa are nearly equal. Only in terms of losses, water is noticeably superior to wind. This may be caused by the fact that water capacities are geographically closer to demand centers in Southern Germany and France. Note that the general results are for the whole system and local effects are not observable.

The price comparison allows for a local analysis. As could be expected, high wind input significantly reduces prices in Northern Europe while high water availability reduces prices in the Alpine countries and large parts of France and Germany. With large amounts of water energy even small price reductions in Northern Europe can be obtained while high wind input only leads to additional price

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[t] 8 a.m. till 8 p.m.

reductions in the Alpine countries in case of high water availability. Although the general results for high wind input and low water availability and vice versa are nearly equal, the price comparison yields a local, strongly differentiated result (Figure 4). High water availability leads to lower prices in large parts of France, Southern Germany, Switzerland and Austria. High wind input leads to lower prices in Denmark and large parts of Germany. Northern France is nearly unaffected by water and wind input since no significant wind capacities are installed at the French coast. The Benelux counrties show a mixed price influence. While the Netherlands profit from high wind input, Belgium has to face a price increases. In case of high water availability Belgium faces reduced prices while the Netherlands have to compensate the decreased wind input with (costlier) fossil plants.

Altogether the analysis shows that the grid and the installed capacities are not sufficient to distribute cheap electricity in the whole system, therefore causing local price differences.

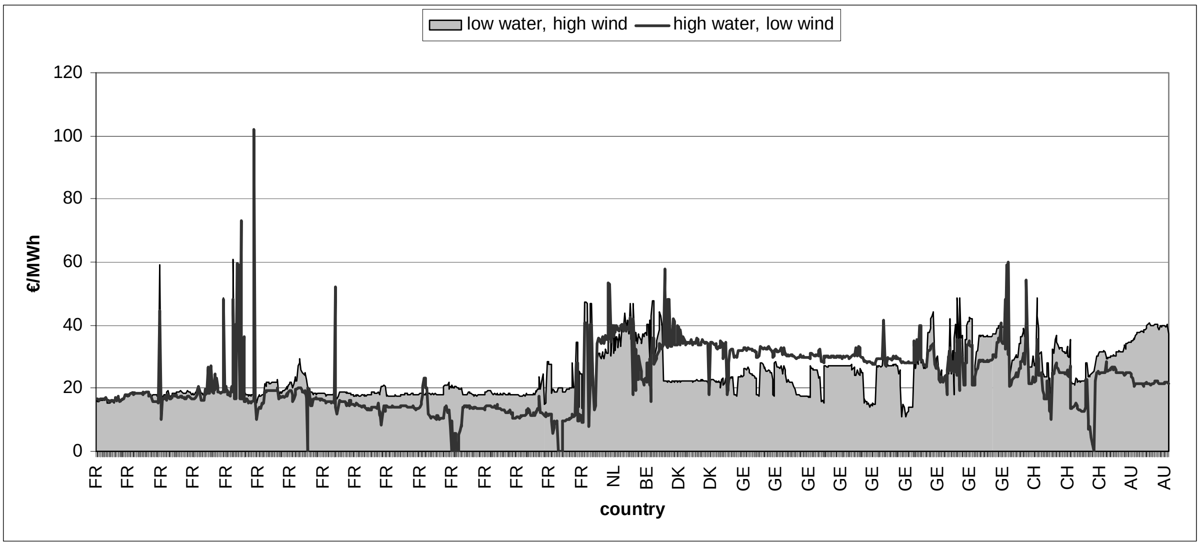

Figure 4: Comparison of nodal prices in times of high wind or water input

4.3 Comparison of all results

While the already existing wind capacities yield small price increases in the Benelux in average demand situations, in peak load situations parts of Belgium have to face notable price increases (Figure 5). Surprisingly, in the average scenario the Northern part of Belgium has to face higher prices while during peak load conditions Southern Belgium has a higher price level. Also, a clear difference in the price level between Northern and Southern Belgium can be observed during peak load, again indicating the need for grid extension. The Netherlands compensate possible wind congestion effects partly by own wind capacities that reduce prices compared to periods with low wind input in which fossil plants - mainly gas and oil fired - have to meet demand. Therefore the average nodal price in the Benelux countries decreases by about 5% during times of high wind input in both the average demand and the peak demand case. For Belgium alone the prices increase by about 0.9% in the average case and about 5.2% during peak load in times of high wind input, signaling a clear impact of wind input. The further extension of wind capacities in Germany - especially the ambitious goals concerning offshore wind - will cause additional congestion if no simultaneous grid extensions take place to transport these large amounts of electricity to the demand centers in Southern Germany.

Furthermore the analysis shows that the nodal approach is superior to uniform pricing. Based on the existing grid in Germany and its surrounding countries, an average welfare gain of 0.8% is possible. That sounds low in terms of percentage but amounts to a sum of 800Mio € per year for the investigated area. In times of high wind input additional welfare gains are possible (Figure 6). Also, additional welfare gains of about 0.9% to 1.6% can be obtained by the extension of wind capacities, offshore and onshore.

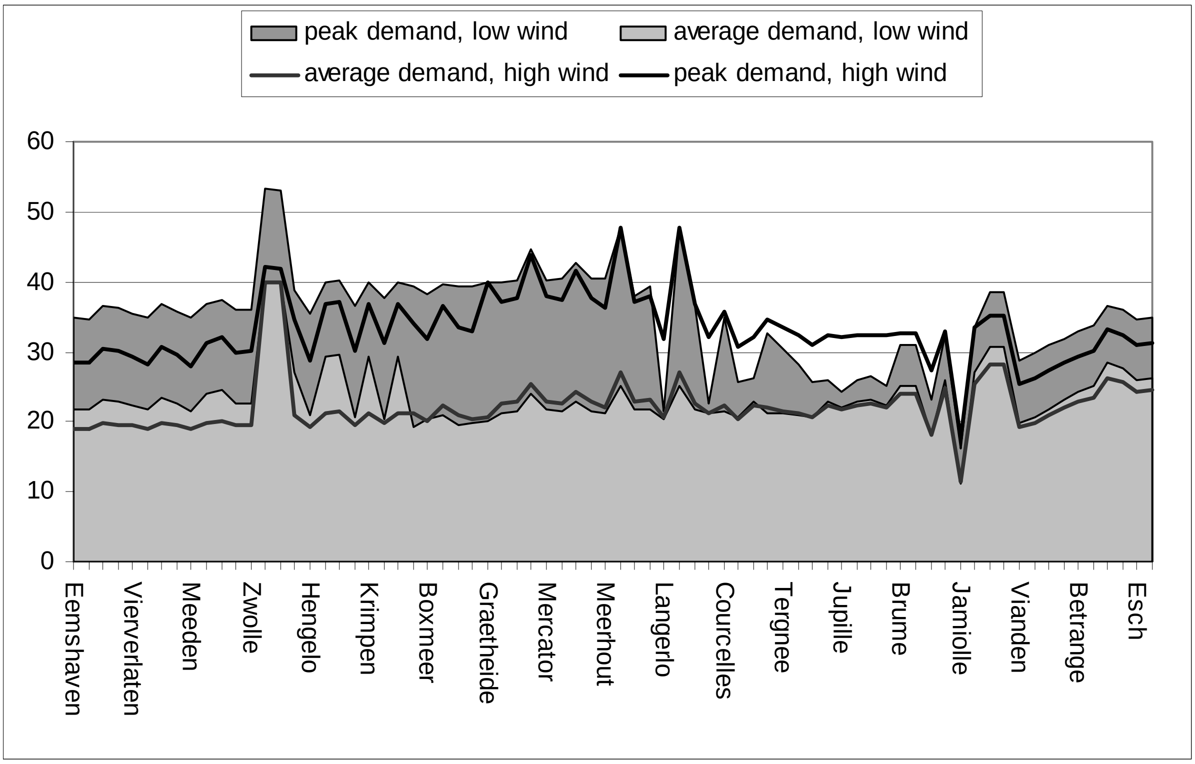

Figure 5: Comparison of nodal prices in the Benelux in times of average and peak load

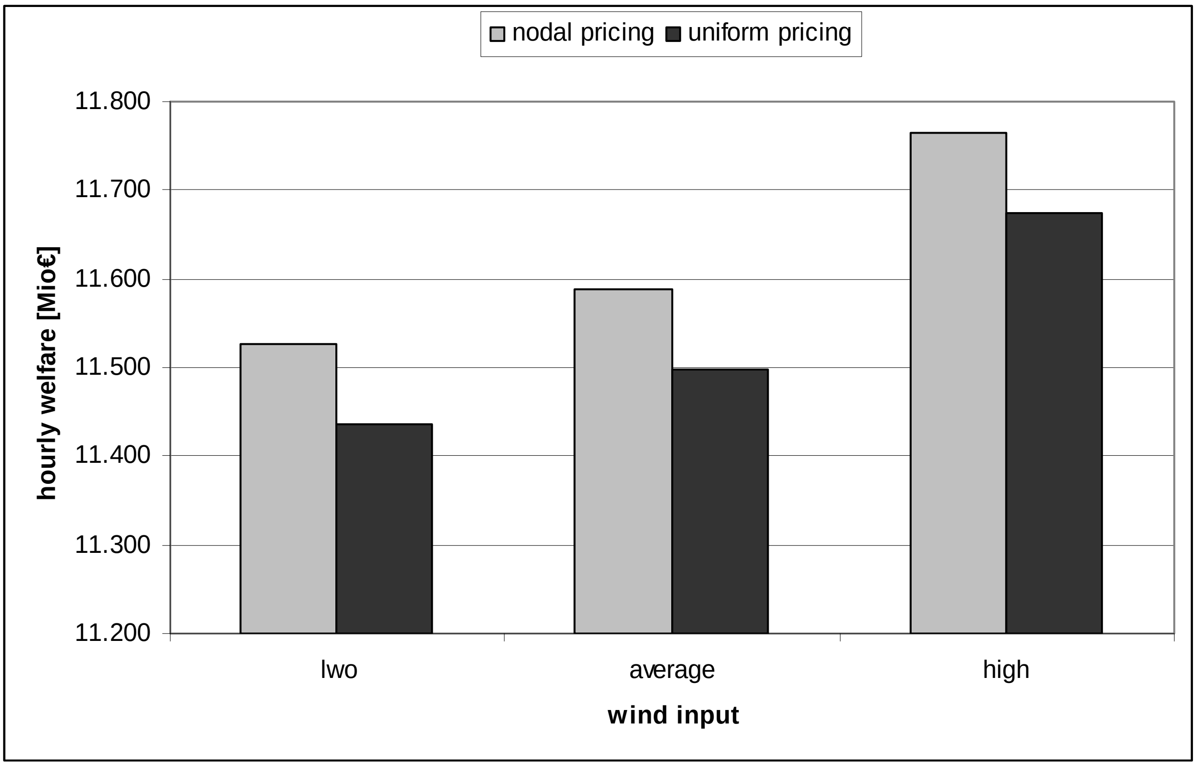

Figure 6: Welfare comparison in the existing grid

5 Conclusions

This paper has analyzed the impact of German wind capacities on the Benelux using a nodal pricing mechanism. While there is a notable impact, the price increase is rather low on average. In times of high wind input mainly Belgium and Southern parts of the Netherlands face slightly higher prices whereas the Northern and Western parts of the Netherlands profit from increased local wind input. During peak load situations high wind input tightens the situation in Southern Belgium while the Netherlands face a significant price decrease. The planned extension of German and European wind capacities changes the situation. In particular the Northern parts of the Netherlands will face price increases caused by high wind input in Northern Germany. Therefore grid extensions in Germany are urgent to prevent further congestion.

Moreover, we illustrate that there is a welfare increase of about 0.8% on average if the existing uniform pricing mechanism is replaced by a nodal pricing approach. This amounts to a gain of circa 800 Mio € per year in the investigated system - consisting of Denmark, Germany, the Benelux, France, Switzerland and Austria. In addition the price impact of wind and water energy is found to be concentrated locally. While Northern countries profit from times with high wind input, southern countries profit from a high availability of the installed water capacities.

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Appendix A: Grid Extensions for Scenario: Impact of German wind on the Benelux

Country	From	To	Line type	Extension type
Germany	Görries	Lübeck Herrenwyk	380 2x	build
	Lübeck Siems	Krümmel	380 2x	build
	Lübeck	Audorf	380 2x	build
	Wilhelmshaven	Conneforde	380 2x	build
	Emden	Diele	380 2x	build
Netherlands	Diemen	Velsen	380 2x	upgrade
	Velsen	Bleiswijk	380 2x	build
	Bleiswijk	Maasvlakte	380 2x	build
Belgium	Avelin	Avelgem	380 2x	upgrade
	Aubange	Moulaine	380 2x	build
France	Villarodin	Grande Ile	380 2x	build
	Chevalet	Argoeuves	380 2x	build
Austria	St.Peter	Tauern	380 2x	build
	Südburgenland	Mellad	380 2x	build