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A Time-Variant Welfare Economic Analysis of a Nodal Pricing Mechanism in Germany

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Abstract

Nodal pricing has emerged from a theoretical approach to a practicable and efficient tool for network and congestion mangement. Experiences from North America and New Zealand have proven nodal pricing to be workable without serious technical problems. Continental European electricity grids like the German one are still based on a uniform pricing mechanism. This study simulates to model a nodal pricing mechanism in the German high voltage grid to estimate the impacts on electricity prices, generation and consumption. In particular, the impact of varying wind energy is analyzed since none of the existing nodal pricing markets has comparable wind capacities. The model is based on reference days with a 24 hour scheme taking into account unit commitment decisions and partial load conditions. Power flows are calculated based on the DC Load Flow Model using a slightly modified version of the traditional approach (Schweppe et al., 1988, Stigler and Todem, 2005). The results show that a nodal pricing mechanism yields a higher social welfare than a uniform price. The impact of wind energy on a nodal pricing mechanism is within predictable boundaries. The results also indicate that nodal pricing is a sufficient tool for estimating necessary grid extensions due to offshore wind capacity implementations.

Key words: electricity, nodal pricing, welfare, Germany, wind energy
JEL-Code: L94, L51, D61

Abbreviations

AC	alternating current
BETTA	British Electricity Trading and Transmission Arrangements
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
DC	direct current
DCLF	DC Load Flow model
DENA	Deutsche Energie-Agentur (“German Energy Agency”)
DEWI	Deutsches Windenergie-Institut („German Wind Energy Institute“)
EU	Europan Union
ETSO	European Transmisssion System Operators
FERC	Federal Energy Regulatory Commission
GAMS	General Algebraic Modeling System
GDP	gross domestic product
GW	Gigawatts
ISO	independent system operator
kV	kilovolts
MW	megawatts
MWh	megawatt hours
NLP	non linear optimization problem
PSP	pump storage plants
TSO	Transmission System Operator
UC	Unit commitment
UCTE	Union for the Coordination of Transmission of Electricity
VDI	Verein Deutscher Ingenieure (“Association of German Engineers”)

Nomenclature

Symbols:

b_{jk}	line series susceptance [1/Ω]
d_n	demand at node n[MWh]
g_{jk}	line series conductance [1/Ω]
g_n	generation at node n [MW]
g_n^{max}	maximum generation capacity at node n [MW]
H	height [m]
L	losses of real power [MW]
ni	net input [MW]
P_{jk}	real power flow between two nodes [MW]
P_i	real power flow at line i [MW]
$P_{L\,jk}$	losses of real power between two nodes [MW]
P_i^{max}	transmission capacity constraint at line i [MW]
PSP_{up}	PSP upload [MW]
PSP_{down}	PSP generation [MW]
$PSP_{storage}$	storage amount [MW]
p_n	price at node n [€/MWh]
p_u	uniform price [€/MWh]
on^t	binary plant condition variable (on = 1, off = 0)
r_{jk}	line resistance [Ω]
$U_{j,k}$	voltage magnitude at a node [volts]
v	wind speed
W	welfare [€]
wi	wind input [MW]

x_{jk}	line reactance [Ω]	Θ_{jk}	voltage angle difference [rad]
z_{jk}	line impedance [Ω]		
z_0	roughness length		

Indices:

down	downward (generating)	ref	reference
i	line between node j and node k	storage	Storage
j	node within the network	t	time periode
k	node within the network	u	uniform
max	maximum	up	upward (storing)
n	nodes within the network		

1 Introduction

Germany's electricity sector faces serious challenges in the upcoming years. One of the main concerns is the integration of renewable energy sources, mainly wind energy, into the grid. But also the questions of necessary plant capacity investments, efficient competition within the network and the development of the European energy market, especially regarding spare cross border capacities, are urgent topics. In theory and more recently in practice nodal pricing has emerged as a tool for efficient network and congestion management. Nodal prices reflect the locational value of energy, which includes the energy cost and the cost of delivering it. High locational prices indicate an insufficient situation regarding generation and network capacities. Therefore it can also aid in the decision process where to extend the grid. Although working properly in the electricity markets of PJM and New Zealand, it is not used in any European market.

Leuthold et al. (2005) are among the first ones applying the nodal pricing approach in Germany. They analyzed the integration of offshore wind capacities under nodal pricing conditions. They conclude that an integration of 8 GW offshore in the existing grid without additional extensions and an integration of 13 GW with grid extensions are possible. As the underlying model is time static crucial aspects like varying demand and wind input are considered through different reference cases. Also, cross-border flows and unit commitment decisions are neglected. Within this paper, the approach is extended taking into account time as an additional parameter. Also, neighboring countries and therefore cross-border flows are part of the model. Load flows are calculated within the DC load flow model, i.e. neglecting reactive power flows. The model is based on reference days with a 24 hour schedule. Demand, reference prices and wind input are time variant. Optimal generation is calculated taking into account unit commitment, start-up costs and partial load conditions as well as pump storage plants. The model assumes a competitive market. Aspects of market power are not considered.

After giving an overview about the theoretical background the present study describes the extended model and summarizes the obtained results. Section 2 outlines the political and institutional framework and gives a literature review on the topic of nodal pricing. Section 3 explains the underlying model and its components. First, the welfare optimization as proposed by Schweppe et al. (1988) is examined and the necessary adjustments are explained. Second, the considered time constraints are reviewed including a short overview about specific aspects of wind energy integration into electric networks, the unit commitment problem and optimal dispatch as well as the simulation of pump storage plants. Finally, the implementation of the model in GAMS is shortly presented. Section 4 informs about the input data and its integration into the model including the generation cost functions for partial load and plant start-up as well as the wind input schedules. Section 5 describes the analyzed scenarios. We start with a base case comparison of nodal and uniform pricing with average reference values. Furthermore, the impact of varying wind energy is examined by calculating several reference cases with different load and wind schedules. Finally, the implementation of offshore wind capacities into the existing as well as an extended future grid are modeled. Section 6 presents and analyzes the obtained results. Section 7 concludes.

2 Background

The European electricity markets have faced serious changes over the last decade. With the EU directive of 1996 liberalization and competition were introduced to a market that was formerly characterized by regulated monopolies.[1] The directive intended to liberalize the national markets and to improve and extend cross-border trade. The aim is to develop a single European electricity market in the long run. In 2003, the second EU Electricity Market directive was adopted to accelerate market opening.[2] However, at present the European Electricity market if far from being integrated. The European Commission states that the main reason for the lack of market integration are the insufficient interconnection capacities between member states that lead to congestion and therefore to price differences between the member states (European Commission, 2005, p. 5). The Florence Process has been created to develop rules for a more efficient management of cross-border trade. In this context the question of how to manage congestion becomes increasingly important, in particular because the EU directive only sets general principles and does not dictate a certain mechanism.

Beside the question of efficient cross-border management electricity markets also face serious investment decisions in the upcoming years. In Europe about 300 GW of capacities have to be replaced or newly installed between 2010 and 2030 (Josefsson, 2005, p.7) with about 50 GW in Germany alone (Wustmann, 2006, p. 2). Although the main concern of investors is the plant type, the question where to site a new plant can have a significant influence on the overall system situation. Another significant change in the recent years has been the extension of renewable, decentralized generation. Especially the further increase of wind capacities from about 34 GW in 2004 to 72 GW in 2010 is one of the main elements of this process (EU, 2006). To cope with this upcoming generation structure the grids will have to be extended. Both decision processes can be supported by a nodal pricing mechanism as price spikes and price differences yield clear signals where grid or capacity extensions are necessary.

This paper picks up the problem of congestion management and analyzes the actual situation in Germany's electricity system. The focus is on the impact of wind energy and the integration of offshore wind capacities while cross-border trade issues are not considered in detail. The analysis is based on a nodal pricing approach. The basic concept of a spot based electricity market was developed by Bohn et al. (1984) and Schweppe et al. (1988) and has been adopted in several studies since then. Further seminal contributions especially with respect to investment and transmission contracts were made by Hogan (1992, 1998, and 2003). Beside theoretical papers empirical studies based on nodal pricing have been provided for England/Wales, Italy, California, Austria, and Germany. Green (2004)

[1] EU Directive 96/92/EC
[2] EU Directive 2003/54/EC

developed a thirteen node model of the transmission system in England and Wales to analyze the impact of different pricing mechanisms concluding that the introduction of a nodal pricing mechanism would lead to a general welfare increase of 1.5 %. Ding and Fuller (2005) analyzed the distribution of consumer and producer surplus under different pricing mechanisms for a stylized Italian high voltage grid. They show that uniform and zonal pricing lead to perverse incentives for generation expansion.

Todem et al. (2004) analyzed the situation of the Austrian grid using nodal priced congestion management on the background of Austria's role as an electricity transfer country. They developed a model respecting unit commitment decision and the distinction regarding the large share of hydro plants in Austria. They show that the Austrian grid faces serious congestion leading to a price difference between the South and the North of the country. Todem et al. conclude that the best way to overcome this problem would be the construction of an additional 380 kV line. Leuthold et al. (2005) took up the problem of integrating large scale offshore wind projects as presented in DENA (2005) and developed a model to implement a nodal pricing mechanism in Germany. They demonstrate that nodal pricing is superior to uniform pricing and conclude that when using nodal pricing 8 GW offshore wind capacities can be implemented without grid extension and additional 5 GW if the North West German grid will be extended. As this approach is time static important aspects of electricity markets have been neglected. This paper is mainly based on the approach as presented in Todem (2004), especially regarding the DC Load Flow Model, and Leuthold et al. (2005).

Nodal pricing is theoretically proven to be superior to other network management mechanisms, but additional equipment is necessary to maintain a properly working electricity market. To reduce the risk involved with varying nodal prices, an efficient hedging system for transmission costs has to be established as this is not a component of the nodal pricing mechanism itself. The problem of sufficient liquidity at each node will be diminished in practice when several trading hubs appear at which the bids and offers of different nodes are traded. Nodal pricing has proven its practical efficiency in North American and New Zealand. It has been implemented in the North-East American electricity market of PJM in 1998 and has also been adopted by the New York and the New England Independent System Operator (ISO). In recent years PJM extended towards the Midwest ISO, now covering 15 states and 164 GW generation capacities. In New Zealand nodal pricing has been introduced to the electricity market in 1996 covering a system with 244 nodes. However, European markets have not adopted the concept. In the UK the British Electricity Trading and Transmission Arrangements (BETTA) has been launched in 2005 introducing an independent system operator but no locational wholesale price mechanism. In Norway zonal pricing and in Sweden, Denmark and Finland counter-purchases are used as congestion management method (Bjørndal et al., 2002). Between continental European states many different trading mechanism are applied (ETSO, 2004), while at the national level uniform pricing mechanism with separate energy and transmission prices are used. The actual price system in Germany consists of a separate energy and a transmission market. The transmission tariff is a two stage tariff including a fixed component in relation to the peak load and a variable component for the energy amount. The tariffs differ for companies but are uniform within the company's grid area, therefore no real relation to specific grid situations, congestion or impact on the system is possible.

3 Model

3.1 Optimization problem

The optimization is based on a social welfare approach as presented by Schweppe et al. (1998) with respect to the necessary constraints if time is considered. In order to calculate welfare, demand and supply functions for each node have to be approximated. Based on reference values for demand, price and elasticity, a linear demand function has been calculated. The supply function is based on the marginal cost function of the plants located at a node. Under perfect competition conditions the price would equal the marginal costs of the last plant running. In the case of congestion it may not be possible to supply the requested amount of energy, since the actual generating plant has not to be attached to the demand node. If the grid capacity prevents the optimal amount of energy from being transported to the node, the price exceeds the marginal costs and the difference can be considered as congestion rent, lowering the welfare. This indicates inefficiencies and results in higher prices for consumers.

The welfare function is optimized respecting the power flows within the system, the energy balance, and the generation capacities:

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

s.t:

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

$$g + wi + PSP_{down} - PSP_{up} - d - ni = 0 \quad \forall n,t \qquad \text{energy balance} \tag{3}$$

$$on_n^t \cdot g_n^{\min} \le g_{n,t} \le on_n^t \cdot g_n^{\max} \qquad \text{generation constraint} \tag{4}$$

The cost function is a combination of an increasing stepwise function with a decreasing marginal cost function per step and additional cost blocks for start-up. Power flows within the system are calculated using the DC Load Flow Model as presented in Leuthold et al. (2005). The energy balance takes into account the varying wind energy input, which is given as an external parameter, and the pump storage facilities. Generation capacity restrictions are calculated for each plant at each node. To model the uniform pricing mechanism an additional constraint is introduced into the model ensuring that prices are equal at each node within Germany:

$$p_n - p_u = 0 \qquad \text{price equality constraint} \tag{5}$$

As the calculation is made for 24 hours, every single constraint has to be fulfilled at each hour and the welfare is then summed up. To simulate a realistic demand behavior the reference demand varies over time, following classical demand schedules with peaks during the morning, noon and evening hours.

3.1.1 Unit commitment and optimal dispatch

Since fossil plants are restricted by thermal conditions, they cannot be turned on- or offline within seconds.[3] According to the type of plant, start-up can take a few minutes for small gas turbines up to several days for large nuclear plants. Thus, it is necessary to decide on the status of a plant before the actual demand situation occurs. This process is called unit commitment (UC) and is essential for obtaining a cost minimal dispatch as well as securing system stability.

In the model, UC is solved within the social welfare optimization process. The optimal output for each plant is determined taking into account that a minimal output level has to be reached to turn a plant online and a certain time for starting up the plant has to be considered. This introduces a binary variable to the calculation process to determine whether a plant is online or offline. Following Takriti et al. (1998), a minimum online and offline constraint can then be defined:

$$on^{t} - on^{t-1} \le on^{\tau}, \quad \tau = t+1,...,\min\{t + L_i - 1, T\} \qquad \text{online constraint} \qquad (6)$$

$$on^{t-1} - on^{t} \le 1 - on^{\tau}, \quad \tau = t+1,...,\min\{t + l_i - 1, T\} \qquad \text{offline constraint} \qquad (7)$$

Since the time interval referred to is one hour, only the offline constraint has been used, assuming that each plant can be shut down after one hour of running. To further reduce the calculation effort, all plants are allocated into three groups following Voorspools (2003): the must-run units, the peak units and the test group for which the UC process is crucial. Nuclear and lignite fired plants are assumed to supply base load and therefore are must-run plants that cannot be shut down. All gas and oil fired plants are assumed to be able to go online within an hour. Therefore no separate constraints are necessary. The same is true for hydro plants.[4] Coal plants are the remaining ones where the start-up time has to be considered. As only one reference day is modeled the necessary information to decide on the correct start-up time may not always be available within the optimization. Therefore, and to reduce the model size all start-ups for coal plants are assumed to be warm ones. For the unconstrained group, all start-ups are assumed to be cold start-ups.[5] The start-up times are based on Schröter (2004, p. 39). Taking these constraints into account, the model calculates the status and the output for each plant in each hour.

Another restriction in the ability of a plant to alter its output is the so called ramping rate, defining the maximal change in output over a specific time interval. As the model interval is one hour, most of the plant types are able to completely change their output within the minimum and maximum capacity.

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[3] Electrical energy is generated transforming heat energy into mechanical energy. Before generation can start enough heat has to be built up to power the mechanical devices.

[4] As hydro pants have marginal costs of zero they will be running at maximal capacity whenever possible.

[5] This is irrelevant for the time constraint but important for the cost estimation.

Only for base load plants a limiting total amount has been chosen to obviate the use of large plants in case of drastic changing system conditions.

3.1.2 Pump storage hydro plants

The only way to store larger amounts of electricity is to use hydro pump storage plants (PSP). Within the model, PSPs can either demand electricity and fill their storage or use the stored energy and generate electricity. The plants start with an empty storage at 8 pm. If they run in pump mode, 75% of the consumed energy will be added to the storage. If they run in generation mode the according amount of energy is taken from the storage:

$$PSP_{storage}^{t+1} = 0.75 * PSP_{up}^{t} - PSP_{down}^{t} + PSP_{storage}^{t_0} \quad \text{storage equation} \quad (8)$$

$$PSP_{up}^{t} - PSP_{down}^{t} \leq g_{PSP}^{\max} \quad 1^{st} \text{ capacity constraint} \quad (9)$$

$$PSP_{down}^{t} \leq P_{storage}^{t} \quad 2^{nd} \text{ capacity constraint} \quad (10)$$

The pumped or generated amount is limited by the plant's capacity. The PSPs are not part of the demand function, as they are assumed to be price takers, but their consumption has an influence on the overall system situation. Since only one day is simulated, the storage behavior may not be properly modeled, as the storage process largely takes place at weekend nights.

3.2 Implementation in GAMS

The upper constraints are implemented as a non linear optimization problem (NLP) into GAMS[6] and several scenarios with different data sets are calculated. As binary variables are part of the model the problem becomes a mixed integer NLP. Due to solver restrictions the model has been implemented as a relaxed mixed integer NLP, allowing all binary variables to take values between 0 and 1. As no plant can go "partly" on- or offline, these values have to be transformed into fixed binary parameters. This process is carried out repeatedly for the mid-load and peak-load plants. Thus the calculated results are no pure optimal solutions, but are supposed to be rather close to an optimum and sufficient for estimating impacts of different pricing schemes and varying wind input.[7]

4 Data

The underlying grid system is based on the German extra high voltage grid consisting of 364 nodes, 9 additional country nodes as well as 50 cross-border nodes to model all surrounding countries (UCTE, 2004 and VGE, 2005). The model contains 281 220 kV lines and 291 380 kV lines as well as 6 lines with 110 kV. Reference characteristics for each line type are based on Fischer and Kießling (1989, p. 2). Security constraints are considered by a 20 % margin. In addition, 50 country lines with unlimited capacity have been included, connecting the cross-border nodes with the country node and

[6] General Algebraic Modeling System, a tool for the development, solution, and management of large scale optimization problems.
[7] Although the total welfare amount decreases with each calculation step, the total change has been smaller than 0.2%. In addition each modeled scenario has comparable changes, thus the impact is supposed to be the same for each scenario.

representing the grid of the respective country. Cross-border lines between countries are modeled according to their length and voltage level. Therefore, the power flow within a country is assumed to be unrestricted, but the power flow between countries is limited by the existing capacity limits. Generation capacities are mainly based on VGE (2004). Fossil plants are divided into six classes according to the main fuel type and complemented with hydro and pump storage plants.[8] Each plant is assigned to one node. In cases of unclear grid integration, the plant has been attached to the geographical closest node. Thereby, more than one plant can be allocated to one node.

In order to include the economic impacts of wind energy and varying demand behavior, the generation costs are separated into two parts: the actual costs of generation dependent of the output level and the necessary costs for starting up a plant. The actual generation costs are calculated on a marginal cost basis, taking into account partial load conditions. To estimate generation costs each plant class has reference marginal costs for optimal output (Table 1). If the output is lower, a mark-up is considered to take into account efficiency losses. Three mark-ups are defined: one for steam plants[9], one for Combined Cycle Gas Turbine[10] (CCGT) plants and one for gas and oil fired plants[11]. The mark-ups have been transformed into quadratic polynomials with partial load as free variable. The efficiency can be transformed into the specific heat consumption that shows the factor about which the input has to be raised in order to generate electricity (*Figure 1*). The impact is rather low for classical steam plants, but becomes important for peak load units like gas turbines and therefore is crucial in times of rapidly changing wind input conditions.

Additional costs occur if a thermal plant has to start-up or to go offline. The cool-down phase is assumed to be mainly affected by fixed costs parameters like general staff expenses and therefore not considered as the optimization is based on a marginal cost approach. The start-up costs are mainly caused by fuel consumption, as a certain amount has to be consumed before the heat level is high enough to start electricity generation. The cost estimations for start-ups are taken from DENA (2005, p.280). These costs are added as a cost block in the period of start-up. As base load plants are assumed to be must-run plants they have no start-up costs. That may lead to biased results in the long run, but should not influence the price and welfare calculation within the modeled reference time frame.

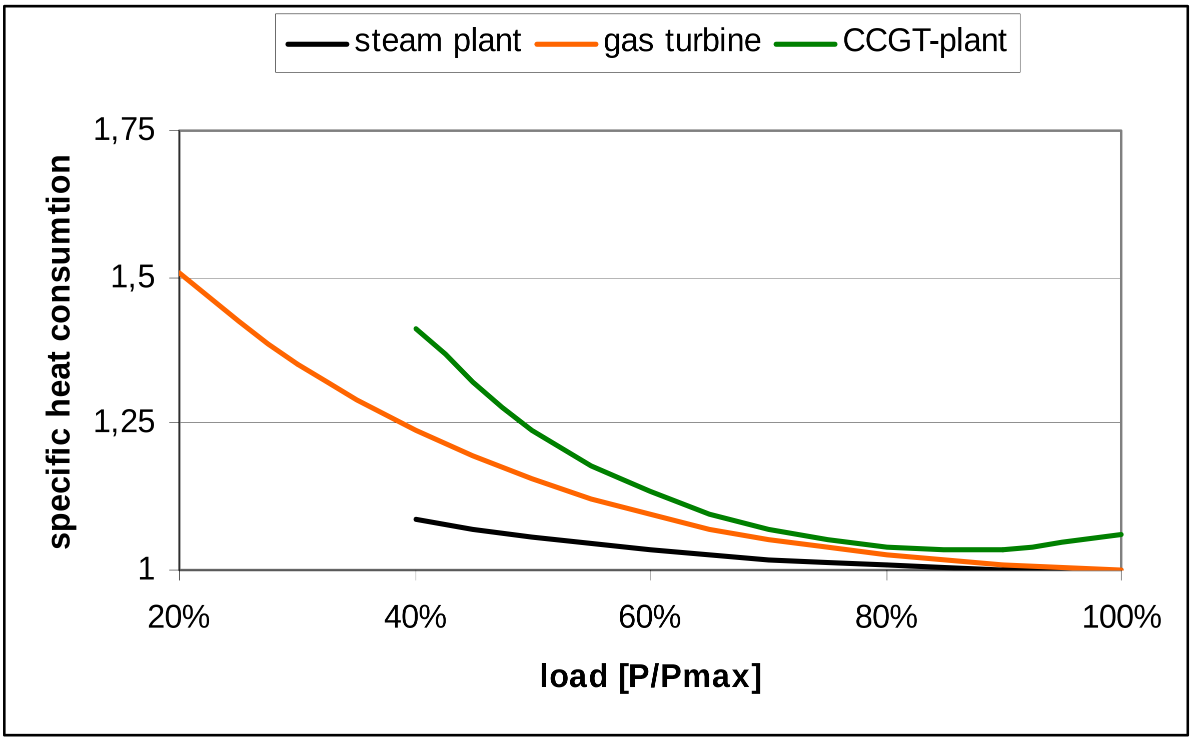
Table 1: Reference marginal costs at maximal output for fossil plants

Plant type	Marginal costs [€/MWh]	Plant type	Marginal costs [€/MWh]
nuclear	10	ccgt	30
lignite	15	gas fired	40
coal	18	oil fired	50

Source: Schröter (2004, p. 7)

[8] Nuclear plants, coal fired, lignite fired, CCGT-plants, gas fired and oil fired.
[9] Based on Baehr et al. (1985, p. 390) and Müller (2001, p. 257)
[10] Based on VDI (2000, p. 344) and (Müller, 2001, p. 264)
[11] Based on Kelhofer et al. (1984, p.4) and (Müller, 2001, p. 262)

Figure 1: Partial load efficiency



Source: own calculation

Wind capacity distribution is based on ISET, IWET (2002) while the capacity amount is based on reported figures for the first half of 2005 (DEWI, 2005) summing up to an installed wind capacity of 17.1 GW. To estimate a realistic energy input wind speed values of seven wind stations have been used to establish six wind zones within the model of Germany. The historic hourly wind speed values are transformed into energy amounts by using a reference wind turbine performance characteristic. The wind speeds in a reference height of 60 meters have been calculated following Hau (2003, p. 457):

$$v_H = v_{ref} \frac{\ln \frac{H}{z_0}}{\ln \frac{H_{ref}}{z_o}} \qquad \text{logarithmic height function} \qquad (11)$$

To obtain average values a roughness length of 0.2, representing farm land with trees and bushes but without surrounding buildings is chosen for all nodes. Wind input is calculated for each hour and node respectively and given as fixed external parameter. Thus, the feed-in guarantee is considered but the impact on the behavior of market participants due to the stochastic nature of wind is not.

In order to gain a differentiated demand schedule for Germany, GDP values for administrative districts and the annual energy consumption are used assuming that areas with high economic power also have a higher demand for electricity. Each district is allocated to the geographically closest nodes. The obtained reference demand is then transformed into a 24 hour demand schedule based on UCTE (2005). Thus, all nodes have the same load curve but with different absolute values. This simplification neglects demand differences between households, industry or commercial customers.

These reference demand values are transformed into a linear demand function using the according EEX spot prices and a demand elasticity of -0.25.

5 Scenarios

Within this paper five scenarios covering three thematic analyses are calculated. In a first analysis nodal pricing and uniform pricing are compared. The aim is to find out whether the nodal pricing mechanism is superior to a uniform pricing approach in terms of social welfare as Leuthold et al. (2005) have shown for a time static case. Two reference cases are calculated:

1. an average winter weekday situation: a high load level has to be satisfied and a moderate amount of wind energy is feed-in;
2. an average summer weekday situation: a relatively low night low level and moderate day load level has to be satisfied while only a limited amount of wind energy is available.

In a second analysis the impact of wind energy on the German electricity system is estimated using the nodal pricing mechanism. In none of the existing electricity markets where nodal pricing is used a comparable generation situation can be observed.[12] Therefore no empirical studies are available analyzing the impact of "uncontrollable" wind energy on the price situation in a nodal pricing market. To estimate this impact three scenarios are analyzed:

3. a low load situation: a summer weekend day with the lowest system load throughout a year during the nighttime and a moderate demand level during the day;
4. a peak load situation: a classical winter weekday with a high load level throughout the whole day;
5. a shutdown of wind turbines during storm.

In a last analysis nodal pricing is used to define necessary grid extensions as price spikes and regional price differences yield signals where to extend the grid. To model the situation two scenarios based on estimations for 2010 are calculated. The results of the first calculation are used to determine the necessary grid extensions for the second calculation:

6. the actual grid with expanded wind capacities : using the planned wind capacity figures for 2010;
7. an extended grid with expanded wind capacities.

6 Results and Interpretation

6.1 Base case comparison of nodal and uniform pricing

At first the winter scenarios are reviewed. During winter the demand level reaches the year's peak load, also the demand level during off-peak time is relatively high resulting in a high grid load throughout the whole day. Additionally, wind input is relatively high. The average input amounts to

[12] Although the market of PJM is comparable in terms of size and demand, no other large market has an equally high amount of wind capacities.

18.5 % of the maximal input. The calculation yields a small welfare surplus of 0.06 % in the case of a nodal pricing mechanism (*Table 2*). In absolute numbers a gain of 0.29 Million Euro per winter weekday can be obtained. One has to take into account that all neighboring countries are part of the calculation. The influence of cross-border flows makes it impossible to determine the real welfare value for Germany alone. As all neighboring countries are only modeled via one single node, the difference between nodal and zonal pricing is supposed to be caused by Germany alone.

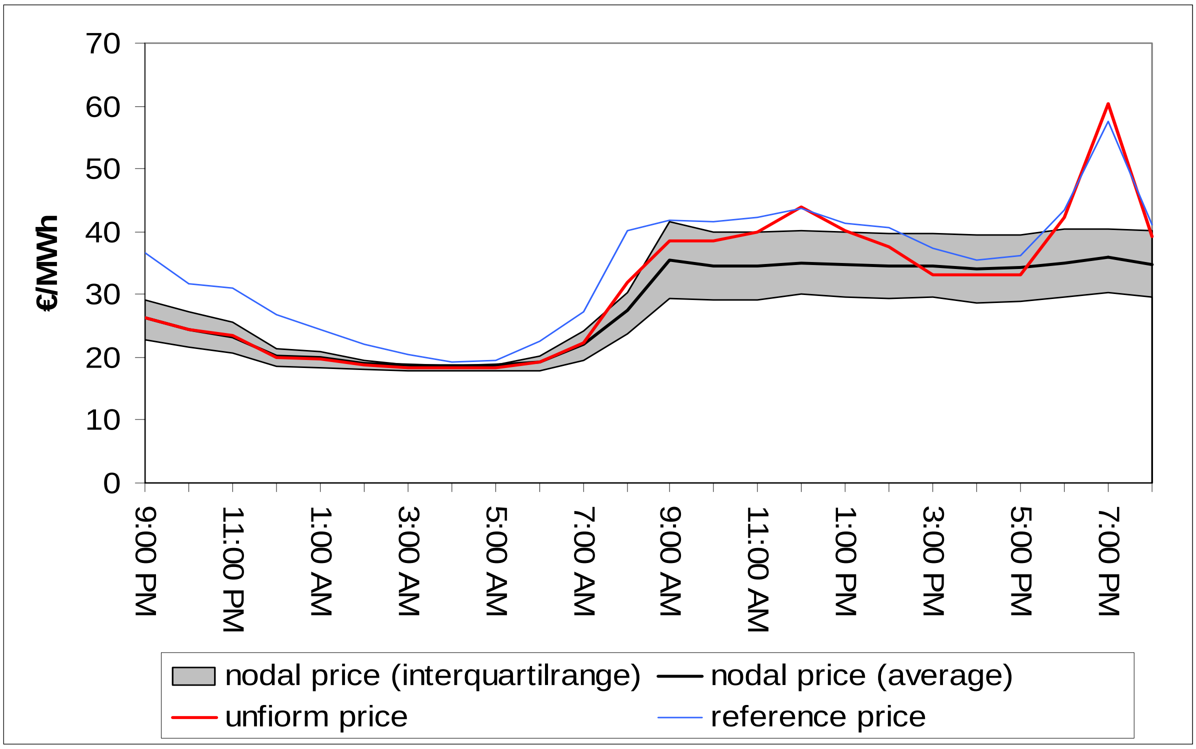
Table 2: Welfare comparison, scenario 1, winter

	Uniform Pricing	**Nodal Pricing**
Welfare [Mio €]	454.07	454.36 (+ 0.06%)
Consumer Surplus [Mio €]	378.39	381.36 (+ 0.79%)
Producer Surplus [Mio €]	75.68	72.99 (- 3.55%)
Losses [% of Generation]	0.35%	0.37%
Average Generation Costs [€/MWh]	11.94	11.93

Source: own calculation

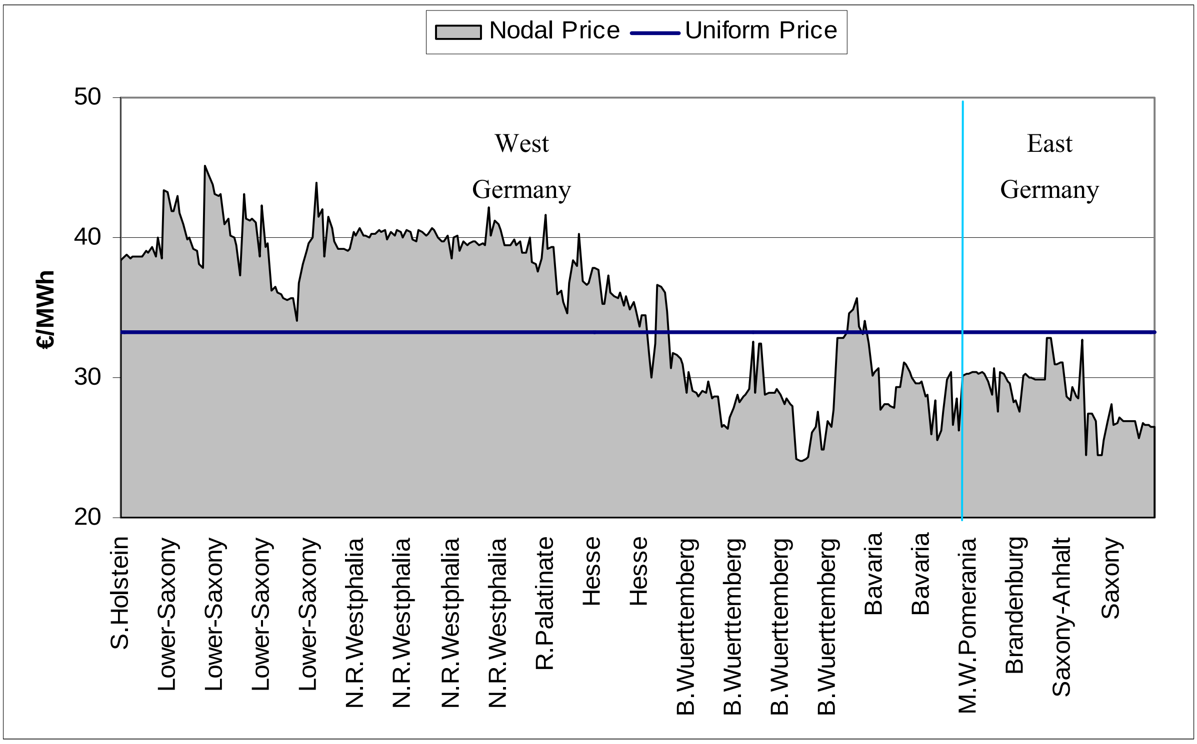
During night time the price difference between nodal and uniform pricing is rather low. During the day nodal pricing yields significant lower prices on average, especially during evening hours (*Figure 2*). The price range during the day is rather constant in case of nodal pricing while significant peaks can be observed under uniform pricing. This is due to the fact that the first congestion may define the price for the whole system while under nodal pricing this price peak is only local. The advantage of nodal pricing is greatest during peak times while in average or low load situations it is comparable to a uniform mechanism. The geographical price differences are rather low during the nighttime. Significant price spikes can be observed at the border to Luxembourg what can be explained with power flows caused by the large pump storage capacities that store water during the night. During the day a clear separation between East and West Germany can be observed (*Figure 3*). This is due to the fact that the former East German grid has only three line connections to the West German grid. As large parts of the Eastern grid are 380 kV lines the prices are rather homogenous in East Germany. West Germany on the other hand has a divergence between the Southern and Northern states which may be due to larger water capacities in the South. The comparison yields that for most of the hours the majority of the nodal prices are below the uniform price.

Figure 2: Price comparison, scenario 1, winter



Source: own calculation

Figure 3: Comparison Nodal/Uniform Price, winter weekday 5 pm



Source: own calculation

The results for the summer scenario are comparable to winter results. The welfare change is slightly lower, while the increase in consumer surplus and decrease in producer surplus are higher. As during the summer time the load level is lower the resulting system conditions are not as tight as in winter times. Therefore, nodal pricing yields on average nearly the same prices as uniform pricing. Only during the peak load situation at noon a significant price reduction is observable. However, as within the model still the whole plant fleet is available while in reality the summer time is used to revise plants, the resulting prices – for both nodal and uniform pricing – may be underestimated. As the total generation capacity decreases the system conditions tighten. This leads to a higher potential of price reduction in case of a nodal pricing approach. The geographical divergences are comparable to the winter scenario with lower prices in East and Southern Germany.

6.2 Impact of wind energy on nodal prices

The second observed question is the impact of wind energy under a nodal pricing mechanism. Given the feed-in priority of wind in Germany the remaining fossil plants have to adjust their output according to the actual wind situation. This may cause additional price spikes during times with rapidly changing wind conditions. Another problem is the fact that most of the wind capacities are located in Northern and Eastern Germany while demand centers are in the Southern and South Western parts. Therefore the transportation of cheap wind energy through the grid may cause additional congestion and lead to increased price differences.

6.2.1 Low load situations

The German base load plants have a minimal capacity of 16.6 GW, adding the installed capacity of wind turbines a possible must-run generation amount of 33.8 GW can occur during high wind phases. The reference demand at the hour of lowest load is 32.5 GW. Since one has to take into account the local distribution of demand and generation a high wind phase may cause additional congestion, because generation greatly outnumbers demand in one area. To model this effect a reference summer Sunday demand curve and two wind schedules have been used, one based on a summer day with nearly no wind input[13] and one with high wind speeds during night hours[14].

The results show a decreased loss ratio[15] in case of high wind input. This may be a result of the increased decentralized wind generation which lowers the need to transport energy from large base load plants to all nodes. Comparing the transport volumes for both cases yield a 5 % higher transport value in case of low wind input.[16] The price comparison yields a surprising result. Although in most hours a general price reduction in case of high wind input is observable, in the late morning and noon hours a different situation occurs. Nearly all nodes face slightly higher prices in case of high wind

[13] 08.08.2002

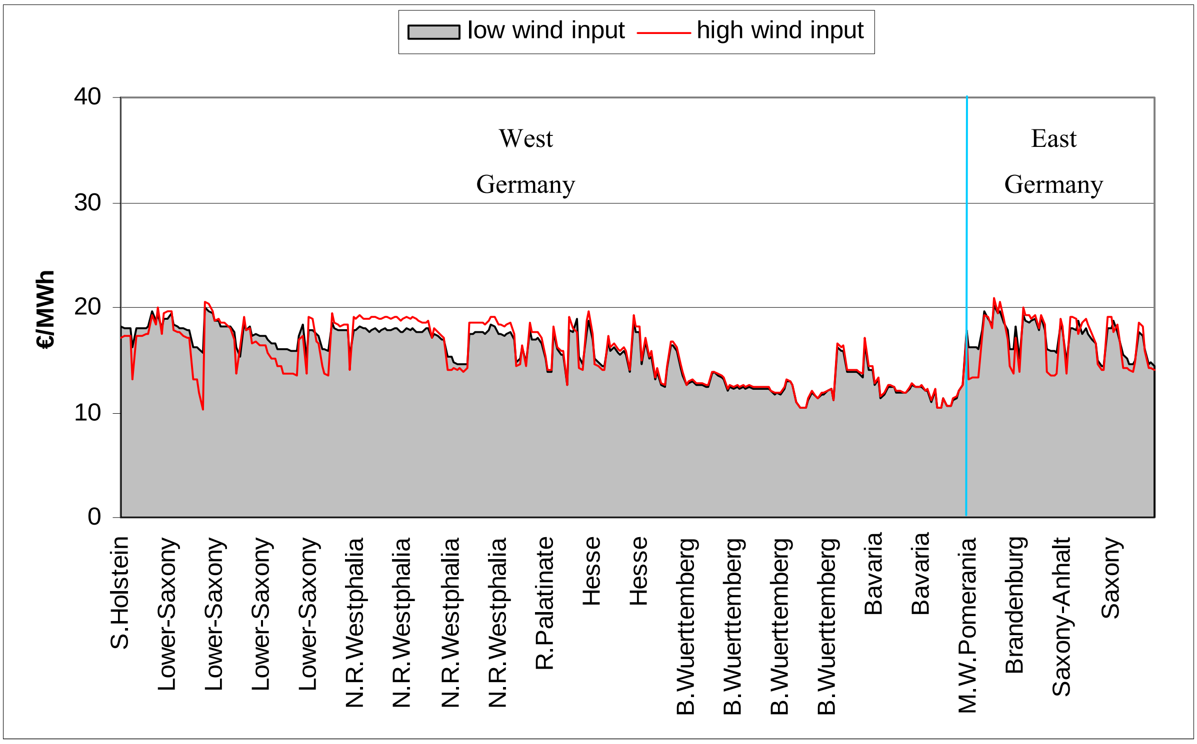
[14] 24.06.2004, The criteria of choice have been the wind speeds during the hours of lowest load.

[15] Total transmission losses in relation to the total generation amount.

[16] For the low wind input case the total line flows sum up to 4.6 TWh while for the high wind input case the line flows amount to 4.4 TWh.

input (*Figure 4*). This can be explained by a combination of wind input and demand level. As the demand increases during noon the base load and wind capacities are not sufficient to satisfy the demand. Therefore mid load plants have to start-up, but as the load level is rather low they only have to run a relatively short time. Thus the start-up costs have a significantly higher price impact than in the low wind input situations when the plants have to run for a much longer time period. In addition the plants are running at a lower partial load level thus having higher marginal costs than in the low wind input case.

Figure 4: Price comparison low/high wind input, summer weekend day 11 am



Source: own calculation

6.2.2 High load situations

In a next step the impact of wind energy in a high load situation is analyzed. For this purpose a winter week day schedule of December has been chosen. Again a high and low wind scenario are analyzed to determine the price impact. Since wind energy is, together with water, the cheapest energy source the TSO will try to satisfy as much demand as possible with these energy sources. That leads to an increased transport amount during high wind phases. As the load level is higher in this scenario the grid situation will be tighter, which may result in additional congestion if large amounts of wind energy have to be transported.

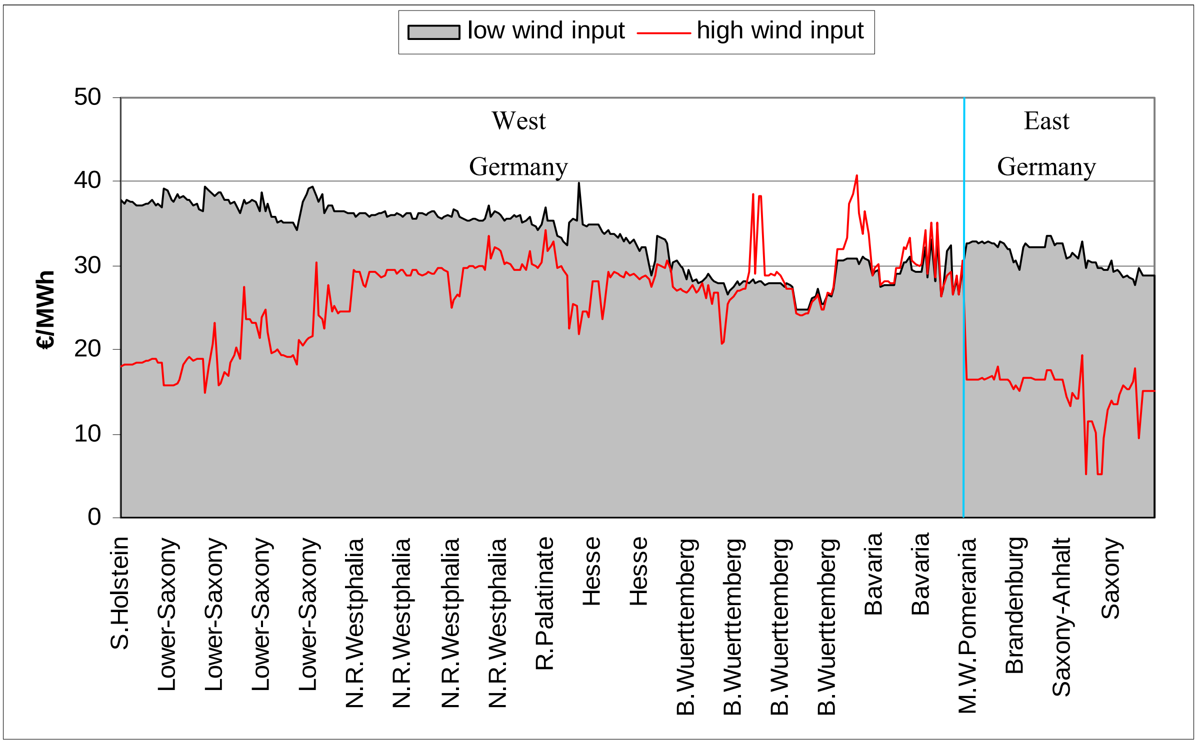
The analysis shows a significant increase in the loss ratio in case of high wind input. This can be explained by the circumstance that the grid load is much higher during the winter days. Since the impact of power flows on losses is quadratic the additional transport caused by high wind input leads to the observed significant loss increase.[17] The decreased need for PSPs may be caused by the reduced possibility to transport energy to the storage plants or the reduced need for energy due to large amounts of cheap wind energy. Analyzing the storage amounts yields an unusual upload in Thuringia at 7 pm in case of high wind input. This is caused by large amounts of wind energy that can not be transported due to congestion. The only possibility is to store the energy at the nearby Goldisthal PSP for later use.

A comparison of prices reveals a general price reduction in case of high wind input. During the night time the price differences start do decrease resulting nearly in a uniform price in the early morning hours. This shows that at a certain demand level wind input can help to relax the grid situation because the decentralized generation reduces power flows from large base and mid load plants to all nodes. On the other hand, large price differences between areas with and without wind capacities are observable during the daytime. Especially the differences between East and West Germany increase significantly. The high load level during winter days stresses the grid. Thus, additional wind input can rapidly lead to congestion. East Germany has a rather homogeneous price level with the exception of Thuringia, which faces the lowest prices. In contrast, there are higher observed prices than in the low wind input case in North Bavaria. This is caused by congestion on the line between Remptendorf in Thuringia and Redwitz in Bavaria. As one of the three connectors between East and West Germany it is a crucial line within the system. The increased wind input leads to a price difference between these nodes of 38.5 €/MWh in average during the day with a peak difference of 50.8 €/MWh at 7 pm. These results show a need for line extension in this area.

In West Germany mainly the Northern states profit from increased wind input as they have large installed capacities. The Southern states have no real advantage of increased wind input as they only have little installed capacities and the grid is not capable to transport the large amounts of cheap wind energy from the North to the South. The states in between face price reductions, however, less than in the North (*Figure 5*).

[17] The transport volume in the high wind input case is 3.5% higher than in the low wind input case.

Figure 5: Price comparison low/high wind input, winter weekday 4 pm



Source: own calculation

6.2.3 Shutdown in case of a storm

Wind turbines go offline if a certain wind speed is exceeded. This is comparable to a plant outage, beside the fact that if the wind speed drops below the limit a wind turbine can easily go online again.[18] As in the plant outage case the most critical point is the fast replacement of the output through reserve capacities. As the model is based on an hourly basis this can not be simulated. But beside short time impacts also medium term impacts can be expected. If a storm leads to large scale outages of wind turbines, fossil plants have to increase output or start-up to compensate the loss. This may cause a price increase as the start-up costs have to be regained in the relative short time of the critical wind speeds since afterwards the wind turbines will again be producing at maximum level. To model this situation a reference day with extremely high wind speeds has been chosen.[19] During the late afternoon wind speeds at the North Sea coastline exceeds the 25 m/s limit for 3 hours. Therefore the output of all wind turbines in Lower Saxony and Schleswig Holstein will drop to zero while the remaining states will have wind input near the maximum. As the outage has to be compensated with fossil plants the prices will increase. The objective is to find out whether the prices increase above the low wind input level in result of an increased need for plant start-up.

The calculation shows nearly the same results as for the high load scenario with high wind input. Minor differences can be observed which are caused by the slightly changed wind input schedule. In

[18] A fossil plant will have to rebuild heat and therefore it will take some time to reach former output again, while the wind turbine is at maximum capacity right after going online again.

[19] 26.02.2002

the critical hours a price increase is observable, especially in Northern Germany. But the prices are still below the low wind input case. Therefore, the outage can be compensated without additional disadvantages for the consumers. The analysis of the use of PSPs shows a slight shift in the generation figures. Amounts that are used in the evening hours in the high load scenario are now consumed earlier to help compensating the outage. While the Northern states have to face price increases the Southern states are nearly unaffected by the outage. The Western states face a slight shift in prices. The Northern states of East Germany surprisingly face slightly higher prices, although their wind input is not affected. Analyzing the line flow on the connector between Saxony Anhalt and Lower Saxony yields that in case of the outage the line flow changes direction. In the normal high wind input situation power flows from West to East Germany, while in case of an outage the flows reverse. Therefore, the prices in East Germany slightly go up keeping the price increase in North West Germany moderate. After the outage the prices go back to comparable levels as in the normal high wind input case.

6.3 Implementation of offshore wind energy in the grid and grid extension

The last scenario evaluates the problem of necessary grid extension to implement offshore wind capacities. Beside the replacement of nuclear capacities the extension of the grid to deal with an increased onshore capacity and implement and transport additional offshore capacities is the main future investment project in Germany’s electricity system. But the question which lines need an upgrade and where new lines have to be build still has not been resolved satisfactory. Nodal pricing is supposed to display the grid situation transparent via price information. Therefore, the model is used to simulate the situation of 2010 and estimate which impacts the additional wind capacities will have.

6.3.1 Estimating necessary grid extension

First, only the generation capacities are extended to simulate the situation of 2010. Therefore, the wind capacities are increased using estimations on a federal state basis and summing up to a total amount of 24.3 GW of onshore wind capacities. Furthermore, fossil plants are added, three nuclear plants are shut down, and offshore capacities are added to the model as they are a crucial part in the future.[20] To test whether the actual grid is capable to transport these amounts of wind energy and how the price situation will change, the first calculations are made without any change to the grid using the winter average and high wind input schedule.

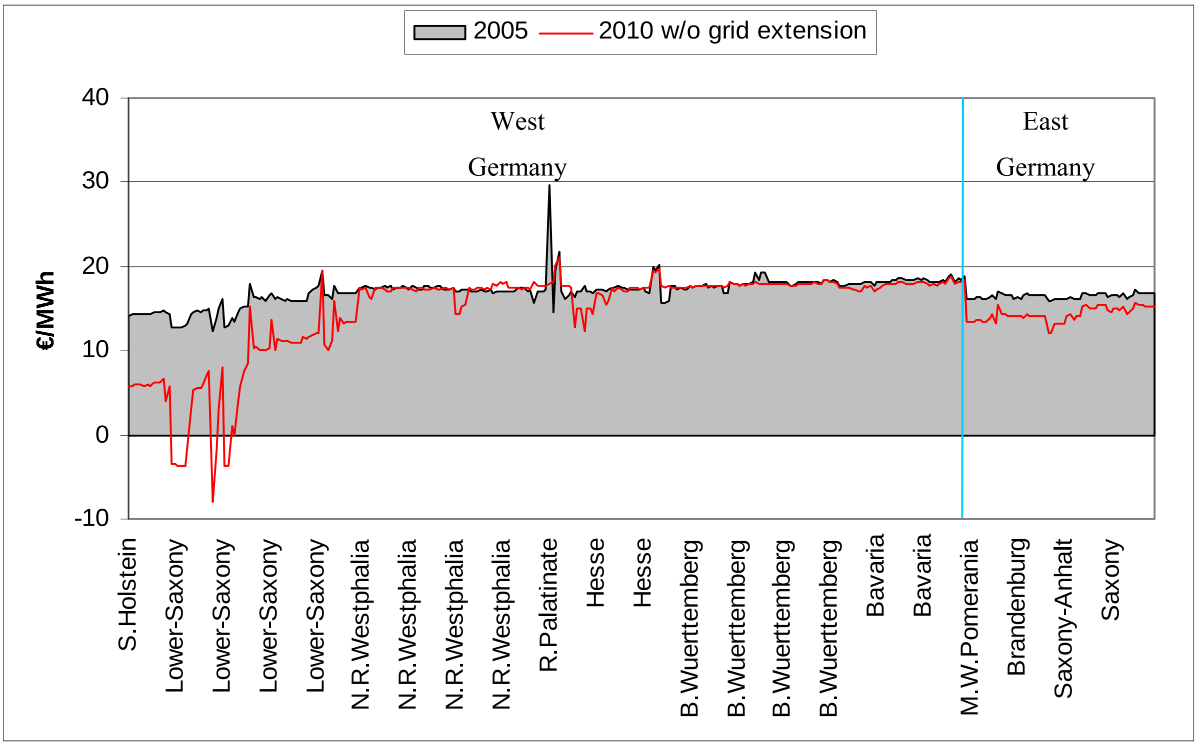
In the average case the results show no new congested situations. The price level decreases as the average wind input is higher in absolute numbers reducing the need for fossil generation. In the high wind input case the results change drastically. While the price differences between West and Southern Germany can be reduced, the price difference between East and West Germany is still significantly high during the daytime. The greatest change can be observed in North West Germany where the offshore capacities are connected to the grid. Here, the prices are on an extreme low level in several

[20] Annex I gives a detailed description of the modeled plant and wind capacity extensions.

hours. Also, negative prices can be observed (*Figure 6*). This is due to the linear demand function and the feed-in guarantee for wind energy. Since congestion prevents further transport of wind energy through the grid the only possibility to fulfill the energy balance constraint is to increase demand at the node. Consequently, prices can become negative if local demand exceeds a certain level.

These results show clearly that the modeled grid is not suited to transport such large amounts of energy. Therefore, the gained price information is used to determine possible grid extension measures. The analysis is focused on the North West of Germany to prevent biased results if additional grid extensions would be included like the obvious necessary extension between Thuringia and North Bavaria. The extension decision is based on the results for 1 am since in this hour the lowest price level can be observed. As the time horizon is rather short the extensions focus on existing lines that can be upgraded and require only short distance lines for new constructions.

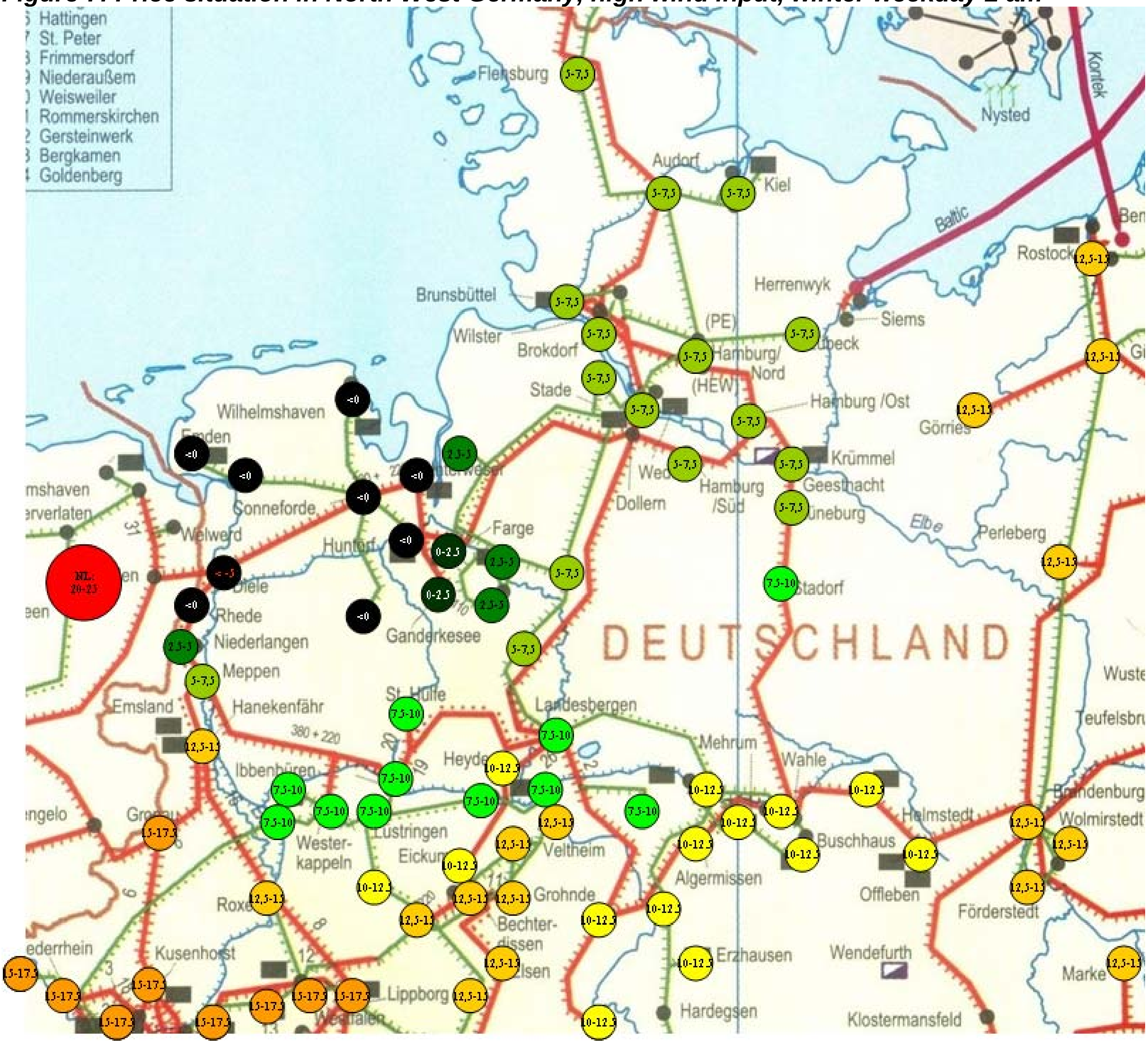
Figure 6: Price comparison high wind input 2005 and 2010, winter weekday 2 am



Source: own calculation

The price differences between the nodes clearly show that the border to the Netherlands is a critical system component regarding the transport of more wind energy to the South (*Figure 7*). On the relatively short distance between Diele and Hanekenfähr the price changes from –8 to +15.2 €/MWh. Therefore, this connection has been chosen to be upgraded from a single 380 kV to a double circuit. To increase the amount of energy that can be transported to the South an additional line will become necessary sooner or later. The chosen extension connects Cloppenburg and St. Hülfte as the price difference amounts up to 15 €/MWh while the distance is only about 40 km. Finally, the 220 kV line between Conneforde and Unterweser has been upgraded to a 380 kV line. Altogether three extensions have been made, but only one new line has been build which should be possible to realize till 2010.[21]

Figure 7: Price situation in North West Germany, high wind input, winter weekday 2 am



Source: own presentation, based on UCTE, 2004

6.3.2 Analyzing the grid extension

In a second simulation the extended grid was used to run the same scenarios. The aim of this scenario is to integrate the planned offshore amounts and not to relieve all congested lines in Germany. In addition the modeled measurements are based on few representative situations and not on a comprehensive analysis covering a whole year. Therefore the obtained results are supposed to reduce the price divergences but are not expected to yield significant welfare increase. The results approve this assumption: the increase in total welfare is only 0.02 % compared to the not extended grid in case of high wind input. Regarding the losses one finds a clear reduction in case of high wind input

[21] None of the lines has been checked for the ability to be upgraded. But it is considered to be easier, in terms of gaining a construction permit, to extend existing line constructions than build new ones.

compared to the actual grid situation. Additional gains due to the grid extension are not observable. The same is true for the average generation costs.

Table 3: Comparison, grid situation 2005 and 2010

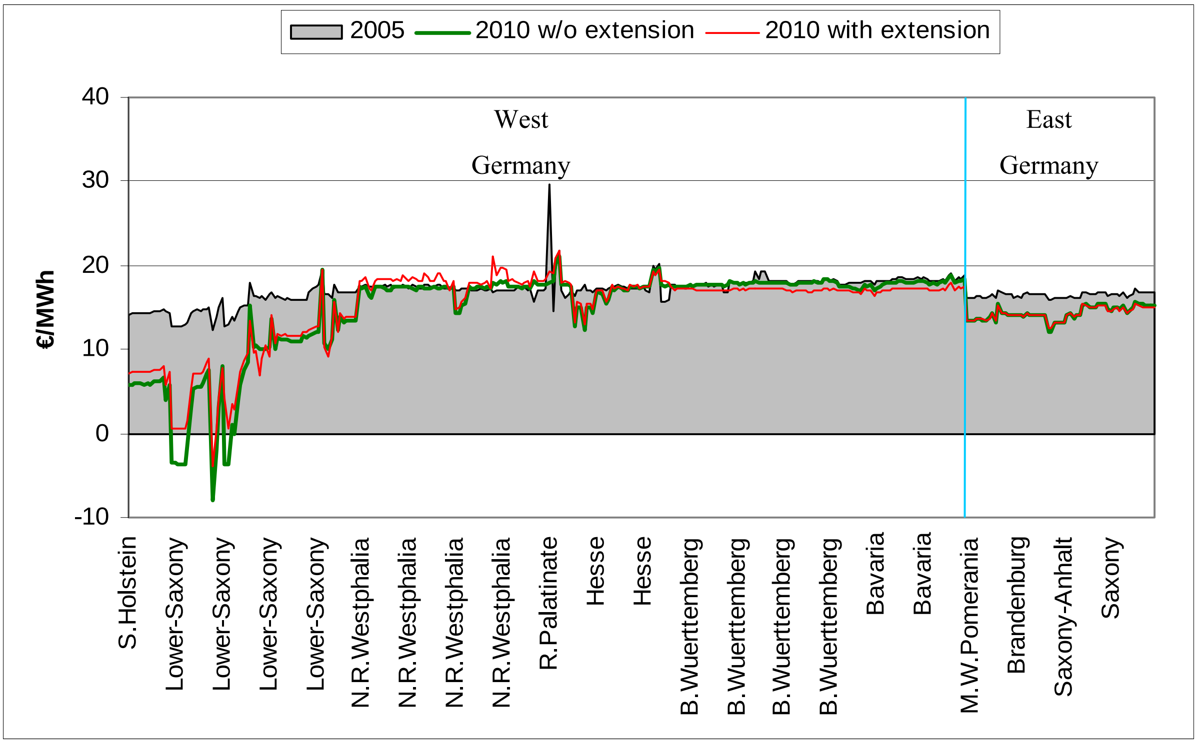
	2005 average	2005 high wind input	2010 average	2010 high wind input	2010 extended average	2010 extended high wind input
Welfare [Mio €]	454.36	465.69	456.09	466.79	456.10	466.88
Consumer Surplus [Mio €]	381.36	402.18	388.11	406.55	387.18	408.69
Producer Surplus [Mio €]	72.99	63.51	67.98	60.24	68.93	58.19
Losses [% of Generation]	0.37%	0.68%	0.39%	0.39%	0.39%	0.38%
Average Generation Costs [€/MWh]	11.93	10.90	11.81	10.23	11.80	10.21

Source: own calculation

Comparing the 2010 scenarios with the 2005 one shows the impact additional wind capacities will have. A significant welfare gain and a reduction of average generation costs due to the larger amounts of wind energy are observable (*Table 3*). However, the comparison of both 2010 scenarios yields only marginal changes. This hints to a general dilemma of grid construction: although the extensions are crucial for system security they have only little effect in general as they are fitted for rare system conditions. Therefore, the price comparison is supposed to reveal whether the chosen extensions were capable to cope with an increased transport of energy in case of high wind input. In general, slightly higher prices in North and West Germany and lower prices in South Germany can be observed indicating that more wind energy can be transported to the South. In the critical situation during the nighttime a significant improvement can be observed (*Figure 8*). Although not all negative prices could be prevented the results show that the undertaken extension can help to relax the grid situation. As the model uses a 20 % security margin the results do not represent critical line conditions at least as long as no line outage occurs. As all lines can be stressed beyond their capacity limits for short time periods it may be possible to transport the modeled amounts of wind energy in reality. But in case of a line outage the situation may become critical.

The analysis of the 2010 situation shows that the German grid will face a tighter congestion situation in the near future. Especially the connections between East and West Germany have to be upgraded and additional lines are needed. The planned extension of onshore and offshore wind capacities can yield problems in times of high wind input and a grid extension will become increasingly urgent to assure system security.

Figure 8: Price comparison: high wind input 2005, 2010 and 2010 extended, winter weekday 2 am



Source: own calculation

7 Conclusions

The study analyzed the current and upcoming grid situation in Germany under a nodal pricing mechanism taking into account varying demand and wind patterns as well as unit commitment and pump storage problems. First of all it could be shown that nodal pricing is superior to uniform pricing although the welfare gain is rather small summing to about 90 Mio € per year. Especially during peak load phases nodal pricing yields significant lower prices on average. Also, a significant increase in consumer surplus and a decrease in producer surplus can be observed which indicates that under nodal pricing the energy price is closer to the marginal costs of supply. The modeled uniform prices are close to the reference prices in the winter scenario indicating that the simulation yields realistic results. The difference between the model and the reference values in the summer scenario can be explained by the lack of plant revisions in the simulation.

Second, the impact of wind energy on the German grid has been analyzed using nodal prices. As none of the existing electricity markets that uses nodal pricing has comparable wind capacities this is the first study to test which impact large scale wind energy input has under a nodal pricing mechanism. The simulated scenarios predict a general price decrease in case of high wind input. However, price increases are observable under certain conditions. During low load phases the additional wind energy can help to reduce grid load due to decentralized generation. But in high load phases the additional energy can not be transported anymore resulting in congestions and increased price differences between areas with large wind capacities and areas without. Also, in low load phases price increases are observable as the large amount of wind energy reduces the running time of fossil plants. Consequently, their start-up costs have to be regained in a shorter time. In addition, they can only run under partial load leading to higher generating costs. Sudden outages of wind turbines due to storm cause price increases that are still below the price level in low wind input times. In both high and low load conditions additional wind input leads to a welfare gain of about 2.5 %.

In a last analysis nodal pricing has been used to estimate the impacts of additional on- and offshore wind capacities on the German grid and to determine where grid extension will become necessary. It could be illustrated that nodal pricing can help to identify critical points within the grid and therefore to send signals where extensions are necessary. Especially in the North West of Germany critical conditions can occur in times of high wind input making security measurement necessary. But also the price divergence between East and West Germany will increase if the connections will not be expanded properly. Especially at the border between Thuringia and Bavaria an extension would be advisable.

The experiences in North America show that nodal pricing is practicable even in large electricity markets. The paper approves the advantages of nodal pricing and shows that even large wind capacities will not yield unpredictable price spikes. Therefore, nodal pricing seems to be a proper tool especially as the congestion situation will increasingly effect the German grid in the future. Nodal pricing is not only capable to aid in efficient network management but can also be used to support upcoming investment decisions. As the general welfare increase seems rather small for Germany alone it is reasonable to implement nodal pricing on a larger scale covering at least several European countries. Especially with respect to the still ongoing debate about efficient cross-border trade management, nodal pricing could be a possible solution. An implementation of different systems in Europe or even within a country can lead to inefficiencies. A nodal pricing mechanism can be implemented to cover both the inner country electricity market and the international trade. Thus, the aim of the European Commission of a single competitive market could be achieved.

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Annex I, extension for the 2010 scenarios

Name	Company	Capacity [MW]	Fuel type
Duisburg-Wanheim	Stw. Duisburg	240	CCGT
Köln-Niehl	GEW RheinEnergie	400	CCGT
Ludwigshafen	BASF	440	CCGT
München-Süd	Stw. München	417	CCGT
Münster/Hafen	Stw. Münster	85	CCGT
Niederaussem	RWE Rheinbraun AG	940	Lignite
Nürnberg-Sandreuth	N-Ergie	180	CCGT
Würzburg/HKW	Stw. Würzburg	100	CCGT
Hamm-Uentrop	Trianel Power	800	CCGT
Herdecke	Mark-E AG	400	CCGT
Hürth-Knapsack	Intergen Power	800	CCGT
Neurath	RWE Rheinbraun AG	940	Lignite
Stendal	Vattenfall Europe Generation	750	Coal

Table 4: new fossil plants within the 2010 scenarios

Source: VGE, 2005

Name	Company	Capacity [MW]
Biblis A	RWE Power AG	1167
Neckarwestheim 1	GKN GmbH	785
Brunsbüttel	KKB GmbH	771

Table 5: offline nuclear power plants within the 2010 scenarios

Source: VGE, 2005 and BfS, 2005