The Effects of Stochastic Electricity Market Modelling on Estimating Additional Costs of Intermittent RES-E Integration

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Abstract

In this paper a stochastic fundamental electricity market model is developed. The model's principle is cost minimization by determining the marginal system costs mainly as a function of available generation and transmission capacities, primary energy prices, plant characteristics and electricity demand. In order to obtain appropriate estimates of the costs of intermittent renewable energy sources for electricity production (RES-E) notably reduced efficiencies at part load, start-up costs and reserve power requirements are taken into account. Since hydro storage is of high relevance when analysing intermittent resources, time-coupling constraints are considered. The system is considered to adapt on increasing RES-E over time by endogenous modelling of investment decisions in conventional power plants. To explicitly account for intermittent electricity production the fundamental modelling approach is extended by introducing a stochastic recombining tree. Exemplary results are presented for a German case study. It is shown that the costs of wind's intermittency are underestimated in deterministic models. The proposed stochastic model, however, can give far more realistic estimates as e. g. the decreasing capacity credit with increasing installed wind capacities can sufficiently be modelled.

Key words: Cost minimization, Electricity market, Fundamental model, Stochastic programming, Value of wind.

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1 Introduction

Within the European Union large amounts of intermittent renewable energy sources for electricity production (RES-E) are expected to be integrated in the electricity markets in the coming years. By their fluctuating nature these RES-E influence the performance of the whole system and hence add costs to the overall system operation. This leads to a strong scientific and public interest in models for estimating these additional costs of intermittent RES-E integration. As wind energy is today's most important intermittent RES-E the following discussion is primarily based on the integration costs of intermittent wind energy in an existing electricity system.

Debates on integrating large-scale intermittent RES-E mainly focus on (i) how to estimate the costs of RES-E's intermittency and (ii) how to apportion the costs between RES-E generators and system operators. These aspects are subject to current research as may be seen with some recently published reviews (cf. Auer et al., 2004; van Werven et al., 2005; Gül and Stenzel, 2005). Within this paper a novel approach to determine the costs of RES-E's intermittency is presented based on estimating the difference between the marginal value of RES-E and the average system price using a stochastic fundamental electricity market model.

In general there is a broad diversity of methodologies to estimate the costs of RES-E's and especially wind's intermittency. Grubb (1991) presents an approach based on assessing the operation costs of a system by analysing the effects of variable sources on the load-duration curve. This statistical analysis considers the effects of variable sources on start-up costs and additional power systems reserve in a static system. Strbac (2002) discusses the additional costs related to the integration of large amounts of RES-E in the British electricity. The simulation approach used is partly based on Grubb (1991) and provides a detailed breakdown of additional costs that are related to distribution, transmission, reserve and unit-commitment. Thereby the system is assumed to be static and hence does not adapt to increased RES-E in the system over time. Hirst and Hild (2004) simulate a relatively small system of a utility in a given year and analyse the additional costs of wind integration. Thereby the costs related to reserve and unit-commitment are taken into account. Finally also DeCarolis and Keith (2005) simulate a small exemplary system in order to assess the costs of increased wind input in a carbon constrained world. Again the system is assumed to be static and next to wind only conventional thermal power plants are considered. Thereby estimates of the costs related to transmission, reserve and unit-commitment are given.

All of the above mentioned studies are somehow based on simulating a given electricity system bottom-up. Such models can generally be expected to be a good choice in order to estimate additional costs of intermittent RES-E, however, they neglect the uncertainties in predicting intermittent sources. Hence, so far research mainly focused on static simulation models or deterministic electricity market models in order to assess the additional costs of RES-E's intermittency. Stochastic effects can then be evaluated by calculating different scenarios. But this does not reflect the actual system operation as the diverse scenarios result in several sub-optima. Thus the question remains: What is the optimal system operation considering all possible states of the stochastic variable? A solution to this problem can be found with stochastic programming (cf. Birge and Louveaux, 1997) resulting in stochastic models.

In this paper such a stochastic fundamental electricity market model to analyse the electricity wholesale market based on a recombining tree is presented. The model is, however, not based on a simulation for a given year rather on an optimization of the cost minimal system operation over a given time horizon. Thereby the system is allowed to adapt on increasing RES-E integration and energy policy effects, i. e. increasing CO_2 allowance prices, by taking endogenous investments in conventional thermal power plants into account. In a case study this model is applied to highlight the effects of stochastic electricity market modelling on estimating the expected additional costs of large-scale intermittent wind integration in the German power system up to 2020. Next to the derivation of cost figures on intermittent RES-E integration the developed approach aims particularly at providing estimates of future electricity prices. Those may be used to assess the profitability of investments in RES-E technologies. At the same time the model allows analysing the interactions between the deployment of RES-E technologies and the development of the conventional electricity market.

The paper is organized as follows: In Section 2 the novel stochastic fundamental electricity market model is discussed in detail. In Section 3 the scenario parameters of an exemplary estimation exercise are presented. In Section 4 the effects of stochastic electricity market modelling on estimating the additional costs of wind's intermittency are analysed. Finally, in Section 5 conclusions and indications for further research are given.

2 Model description

The basic idea of fundamental models is to analyse power markets based on a description of generation, transmission and demand, combining the technical and economical aspects. These models (cf. e. g. Kreuzberg, 1999; Kramer, 2002; Barlow, 2002) often aim at explaining electricity prices from the marginal generation costs. One major assumption of these models is that the electricity spot market operates efficiently. This leads to consider an efficient system operation with minimal costs, satisfying all customer demands. If customer demand is taken as price inelastic, prices will equal to the marginal generation costs of the last unit needed to fulfil the given demand. Of course, this basic approach has to be extended into several directions in order to cope with the reality in electricity markets. In this paper the innovative element is that the intermittency of RES-E is represented by a recombining tree following a stochastic programming approach.

In the following first the general modelling approach is discussed. Based on this discussion a deterministic version of the fundamental electricity market model is described in detail. This is followed by a description of an extension of the model by stochastic programming applying a recombining tree. Figure 1 gives an overview of the symbols used.

2.1 General approach

For the practical implementation of any fundamental model, especially if the additional costs of intermittent RES-E integration are to be estimated, at least the following seven major challenges arise:

- data availability,
- existing capacities,
- unit-commitment,
- investments,
- time resolution,
- regional resolution and
- stochastic modelling.

Applying a fundamental model to represent the dynamics of a given system greatly depends on the data quality and availability. Depending on the market, more or less information on plant capacities and costs, demand patterns and transmission capacities may be available. This may hamper the applicability of a fundamental model and should hence be already taken into account at the beginning of developing such a model.

All fundamental electricity market models greatly depend on the representation of the power plant portfolio of the considered system. Besides often focused thermal power plants (cf. e. g. Kramer, 2002; DeCarolis and Keith, 2005), hydro power plants play a considerable role in many electric power systems, including the European one. At least three cases have to be distinguished: run-of-river plants, hydro storage plants and hydro storage plants with pumping facilities (pumped storage plants). Notably, the storage plants require a modelling approach that encompasses several time steps and possibly stochastic inflow. The number and types of power plants represented in a fundamental model may however vary according to the considered regions and time horizon. With respect to the restricted computing time it may then be necessary not to model all plants separately. One attractive solution is to group the plants to classes according to the main fuel and vintage.

It has been discussed above that in order to cope with the intermittency of RES-E the operation of other units in the power system may change. Thereby the value of flexibility of plant operation to maintain a constant reliability margin may increase. This implies that modelling the unit-commitment is of great importance in order to accurately estimate the additional costs of RES-E's intermittency. Thus important aspects to be considered are start-up and shut-down costs and times as well as part-load efficiencies. In unit-commitment models those are typically modelled using binary variables (cf. e. g. Kagiannas et al., 2004; Yamin, 2004, and the references therein). But this is hardly feasible when modelling a regional or even supra-regional market. Thus in this paper an approximating approach for dealing with part-load efficiencies and start-up costs presented by Weber (2004) is considered that will briefly be discussed below.

With the integration of RES-E in an existing system the rest of the power system will co-evolve over time. All else equal, the costs of intermittency will be less if the generation mix is dominated by flexible plants, i. e. by gas turbines or hydro power plants. Hence, the consideration of intermittent RES-E may lead to a change in the macroeconomic cost-minimized investment behavior in the market. Following this discussion the estimation of integration costs needs to be based on a dynamic representation of the system. This leads to take investments in new power plants into account. However, most studies on integration costs are based on static representations of the considered system (cf. Grubb, 1991; Strbac, 2002; Hirst and Hild, 2004; DeCarolis and Keith, 2005). This paper, on the other hand, takes the dynamic development of the power system over time into account. With respect to the computing time again a mixed-integer representation, as e. g. proposed by Schwarz (2005), is avoided and a linear representation is chosen. This can significantly reduce the computing time but can not ensure that only whole plants and not, for example, half a plant can be build.

As this paper focusses on the additional costs of intermittency, the time resolution should be as detailed as possible. The modelling of seasonal hydro storage necessitates the modelling of a full year and the effects of intermittency on the unit-commitment of the overall system requires an almost hourly time resolution. On the other hand the evolvement of RES-E has to be considered over a reasonable time horizon. Hence, each year of the time horizon needs to be modelled subsequently and the restricted computing time leads to use load segments within a seasonally decomposed yearly model or to model typical days that comprise a defined set of typical hours. In the former framework the modelling of start-up costs is most difficult and thus modelling of typical days is chosen in this paper.

With regard to the integration of a possible high amount of wind power in future electricity system configurations, the consideration of transmission constraints is of high importance. A fundamental model may therefore be divided in different geographic entities. They should preferably represent today's transmission system in a way that possible transmission constraints can sufficiently be modelled. Some authors argue that, on balance, future electricity imports and exports will be more or less the same (cf. Hoster, 1996; Schwarz, 2005). Hence, a regional model without considering the transmission net may be sufficient to represent the future power system. This however neglects (i) the different evolvement of power systems over time and (ii) the spatial distribution of intermittent RES-E. The different evolvement is mainly due to local energy policies. Consider, for example, the nuclear policy in Germany and France. In Germany a phase-out has been decided on whereas in France investments in nuclear power plants are still possible. Hence, the relative supply curves of the systems may change. This may lead to higher imports of comparably inexpensive electricity produced by nuclear power plants in France to Germany. Hence, if connected electricity systems are modelled over a longer time horizon the future electricity transmission may not stay constant. The spatial distribution is another aspect that may lead to model the transmission net in greater detail. The German power system, for example, is defined by a high concentration of installed wind power in the coastal regions in the north. By contrast the electricity demand in these regions is rather low compared to the consumption in the south. Such aspects are, however, not taken into account within this paper to remain a certain degree of simplicity in the case study. Nevertheless, the effects of these simplifications will be discussed.

In general stochastic fluctuations are particularly relevant if the model is to be directly used for short-term predictions or to give an estimate of the additional costs of RES-E's intermittency. Within this paper a methodology to include stochastics in a long-term fundamental model is proposed in order to cope adequately with the integration of fluctuating RES-E. The stochastics considered are consequently mainly those related to wind power fluctuations. Thus, thorough analysis of the electricity market will allow to assess the impact of such stochastic fluctuations.

2.2 Deterministic model

The model determines the marginal generation costs (like most other fundamental models) as a function of available generation and transmission capacities, primary energy prices, plant characteristics and actual electricity demand.

Additionally (and in difference to other fundamental models) the impact of hydro-storage and start-up costs as well as endogenous investment decisions are accounted for. The principle of the model is cost minimization in the considered power network. The deterministic objective function to be minimized can thus be written as:

$$TC = \sum_{r} \sum_{u} \sum_{t} d_t \, f_t \left(OC_{r,u,t} + SC_{r,u,t} + FC_{r,u,t} \right) \tag{1}$$

Thereby the total costs TC are minimized and are calculated by the sum of operating costs $OC_{r,u,t}$, corresponding start-up costs $SC_{r,u,t}$ and fix costs $FC_{r,u,t}$ subject to region r, unit type u and time segment t. This sum is weighted by the duration d_t of a time segment and its frequency f_t in the planning horizon.

The operating costs $OC_{r,u,t}$ are assumed to be an affine function of the decision variable of the plant output $Q_{r,u,t}$. Thereby the decision variable of capacity currently online $L^{\mathrm{onl}}_{r,u,t}$ is introduced (cf. Weber, 2005). The capacity online generally forms an upper bound and, multiplied with the minimum load factor, a lower bound to the output. This allows to describe the difference between part-load and full-load efficiency:

$$OC_{r,u,t} = fp_{r,u,t} \, hr^{\mathrm{m}}_u \, Q_{r,u,t} + fp_{r,u,t} \left(hr^{0}_u - hr^{\mathrm{m}}_u \right) lf_u L^{\mathrm{onl}}_{r,u,t} + oc_u \, Q_{r,u,t} \tag{2}$$

In this equation $fp_{r,u,t}$ gives the fuel price, hr^{m}_u the marginal heat rate between minimum and full load and hr^{0}_u the heat rate at the minimum load factor lf_u. The heat rates are assumed to be constant. If $hr^{\mathrm{m}}_u < hr^{0}_u$ the operators have an incentive to reduce the capacity online. Furthermore other variable costs oc_u, e. g. related to desulphurization of plant exhaust gases, are included.

Start-up costs may considerably influence the unit-commitment decisions of plant operators. In unit-commitment models they are typically modelled by binary variables for unit operation, start-up and shut-down (cf. e. g. Kagiannas et al., 2004; Yamin, 2004, and the references therein). However, this is hardly feasible when modelling a supra-regional electricity system. Nevertheless, an approximation can be done by applying the already introduced capacity currently online $L^{\mathrm{onl}}_{r,u,t}$. The specific start-up costs sc_u then arise, if the capacity online is increased, i. e. when the start-up capacity $L^{\mathrm{stu}}_{r,u,t} \geq L^{\mathrm{onl}}_{r,u,t} - L^{\mathrm{onl}}_{r,u,t-1}$ gets strictly positive. In order to avoid that units are always kept online, the efficiency at part load has to be lower than at full load. The total start-up costs $SC_{u,t}$ are then described by the relation:

$$SC_{r,u,t} = sc_u \, L^{\mathrm{stu}}_{r,u,t} \tag{3}$$

Contrarily to many other fundamental market models, especially with focus on additional systems operation costs, endogenous investments in new conventional thermal power plants are taken into account. This reflects that the system may change due to an increased share of RES-E on total production. Hence, for calculating the fix costs $FC_{r,u,t}$ the choice among different available investment alternatives with specific irreversible fix costs fc_u^{irr} and the decision variable of newly build capacity $L_{r,u,t}^{\text{new}}$ is endogenously modelled:

$$FC_{r,u,t} = a(i, lt_u)\, fc_u^{\text{irr}}\, L_{r,u,t}^{\text{new}} + fc_u^{\text{rev}}\, L_{r,u,t} \tag{4}$$

Thereby the investments are discounted by the annuity factor $a(i, lt_u)$ defined by the interest rate i and the lifetime lt_u:

$$a(i, lt_u) = \frac{i\,(1+i)^{lt_u}}{(1+i)^{lt_u} - 1} \tag{5}$$

Finally, also reversible specific fix costs fc_u^{rev}, e. g. the costs for personnel, for the total installed power plant capacity $L_{r,u,t}$ are taken into account. Note that the decision of investing in new capacity is not binary but continuous.

The key constraint is that supply and demand have to be identical in every region r and at every time step t:

$$\sum_u Q_{r,u,t} + \sum_{r'} (E_{r' \to r,t} - E_{r \to r',t}) \geq D_{r,t} + \sum_u Q_{r,u,t}^{\text{pum}} \tag{6}$$

Thereby the demand is exogenously given by the energy demand $D_{r,t}$ and the decision variable of export flows $E_{r \to r',t}$, while supply is given by the supply of the power plants $Q_{r,u,t}$ and the decision variable of import flows $E_{r' \to r,t}$. As also pumped hydro plants are considered the decision variable of pumping energy for hydro storage $Q_{r,u,t}^{\text{pum}}$ need to be added.

The production $Q_{r,u,t}$ is constrained by the total installed power plant capacity $L_{r,u,t}$ multiplied by an availability factor $\rho_{u,t}$:

$$Q_{r,u,t} \leq L_{r,u,t}\, \rho_{u,t} \tag{7}$$

This production constraint may be formulated alike for the pumping energy $Q_{r,u,t}^{\text{pum}}$ and, as a transmission constraint, for the import flows $E_{r' \to r,t}$ as well as for the export flows $E_{r \to r',t}$.

As this paper specifically addresses the additional costs of RES-E's intermittency it is necessary to consider reserve power requirements within the model (cf. Meibom et al., 2003, for a detailed discussion of the German and Scandinavian markets for power system's reserve). The reserve requirements are included in the capacity balance equation of those plants able to provide them.

$$L_{r,u,t}^{\text{onl}} + L_{r,u,t}^{\text{res}+} - L_{r,u,t}^{\text{res}-} \leq L_{r,u,t}\, \rho_{u,t} \tag{8}$$

Thereby, incremental reserve capacity provided by a single plant is given by $L^{\text{res}+}_{r,u,t}$ and decremental reserve by $L^{\text{res}-}_{r,u,t}$. Besides these restrictions at the plant level also overall reserve restrictions have to be satisfied (cf. UCTE, 2004).

When considering hydro storage plants, storage constraints need to be considered. It is first necessary to describe the filling and discharging of storage. This may be obtained by constraining the decision variable of the storage level $H_{r,u,t}$, which is expressed for simplicity in energy units, not to be greater than the level at time step $t-1$ minus the production $Q_{r,u,t}$ and plus the exogenously given inflow $W_{r,u,t}$ for all hydro storage plants.

$$H_{r,u,t} \leq H_{r,u,t-1} - Q_{r,u,t} + W_{r,u,t} \tag{9}$$

For the pumped storage plants an even further extension of the framework is required. The already introduced pumping energy $Q^{\text{pum}}_{r,u,t}$ and a given cycling efficiency η^{cyc}_{u} is required to formulate the storage level constraints for pumped storage plants. The cycling efficiency is the fraction of the energy recovered when first pumping the water and then propelling it through the turbine again.

$$H_{r,u,t} \leq H_{r,u,t-1} - Q_{r,u,t} + W_{r,u,t} + \eta^{\text{cyc}}_{u}\, Q^{\text{pum}}_{r,u,t} \tag{10}$$

Finally, an adequate terminal condition has to be included for the water reservoirs. One attractive formulation is to require that the final and the initial reservoir level are identical, which can be expressed through the following initial cyclical condition for the hydro plants (thereby the first time step is indicated by $t = 1$ and the final time step by $t = T$):

$$H_{r,u,1} \leq H_{r,u,T} - Q_{r,u,1} + W_{r,u,1} \tag{11}$$

and for the pumped storage plants:

$$H_{r,u,1} \leq H_{r,u,T} - Q_{r,u,1} + W_{r,u,1} + \eta^{\text{cyc}}_{u}\, Q^{\text{pum}}_{r,u,1} \tag{12}$$

2.3 Stochastic model

The aforementioned equations need to be reformulated and extended in order to cope with the stochastics of intermittent RES-E. Instead of considering one operation mode of the system at one moment in time, one has to consider different alternative stochastic states depending on the actual wind power production and other stochastic factors. For the stochastic modelling two types of uncertainties have to be distinguished:

Short-term fluctuations: These comprise mainly the fluctuations in wind power production; but also PV output and electrical load are subject to impredictabilities and fluctuations, which occur in the short-term and where in the long-term a return to the average occurs.

Long-term fluctuations: Especially hydro power exhibits significant yearly variations, which may be considered since they can have a strong impact on generation possibilities, security of supply and CO_2 emissions. Short-term fluctuations are of lower importance for hydro power.

For the stochastic representation a recombining tree is considered. Thereby each typical day t is subdivided in S stochastic stages $s \in \{1, 2, \ldots, S\}$ (that can be equal to the considered duration d_t of a typical hour or may comprise several such typical hours) and for each stage N stochastic states or nodes $n \in \{1, 2, \ldots, N\}$ are distinguished. Thereby the stages allow to reduce the resolution of the stochastic representation. This may be necessary as the stochastic formulation will lead to consider that all decision variables depend on the stochastic nodes. Hence, the number of decision variables increases with the power of N. To comprise several considered time steps to one stochastic stage may therefore significantly reduce the computational burden.

The recombining tree is depicted in Figure 2. Each node is characterized by the respective value of the stochastic variable and its probability of occurrence $\psi_{r,t,n}$ (here the index t is used as the time steps may be interpreted as a subset of the considered stochastic stages). It may be seen that each node n at stage s is coupled with each node n' at stage $s+1$. Thereby transition probabilities $\tau_{r,t\to t+1,n\to n'}$ need to be taken into account. They give the probability that a specific stochastic state is expected to follow a specific state on the proceeding stage. To be more specific: In this paper wind is assumed to be the only stochastic variable, hence the nodes represent different stochastic states, e. g. low, medium and high wind power generation, at a given stochastic stage, i. e. the wind power generation is assumed to be constant in the hours comprised by the stochastic stage. Additionally, at the end of each typical day the transition probabilities to a day of the same type and the probabilities of a shift from weekend to weekday and vice versa are taken into account.

Following this discussion the stochastic model's objective function is a straightforward extension of the deterministic approach in Eq. (1). The key point is that all decision variables are simultaneously indexed over time t and node n and that the different nodes enter the objective function with their probability of occurrence $\psi_{r,t,n}$:

$$TC = \sum_r \sum_u \sum_t \sum_n d_t \, f_t \, \psi_{r,t,n} \left(OC_{r,u,t,n} + SC_{r,u,t,n} + FC_{r,u,t,n} \right) \tag{13}$$

For the other static equations the general approach is to add the index for the different nodes. The capacity, reserve power and transmission equations are examples of such static equations, as may be seen with Eq. (7). However, for dynamic equations, which link different time steps, it is important to account for the transition probabilities $\tau_{r,t\to t+1,n\to n'}$ also. E. g. reservoir fillings at the beginning of a stochastic stage will be determined by the probability weighted average of the filling levels at all nodes of the prior stage.

Giving this formulation of the stochastic model the additional costs of intermittent RES-E integration can be assessed by calculating the difference of the marginal electricity price and the marginal value of RES-E's energy production in the given system. Thereby the marginal value is calculated as a weighted average of the estimated marginal electricity price, taking the RES-E's energy production as a weighting factor.

3 Case study

The description of the developed stochastic fundamental electricity market model has already shown that assumptions on the regional resolution, time horizon and discount rate, generation capacities and investments, electricity demand, energy policy and finally also on the considered stochastics are important parameters of the model. They may considerably influence the modelling results and are discussed for a German case study on the effects of stochastic electricity market modelling on estimating additional costs of intermittent wind integration in the following subsections.

3.1 Regional resolution

The model is developed to account for several regions (within one country or between neighboring countries) coupled by defined transmission capacities. In this case study, however, such interactions are not accounted for. Thus additional costs of transmission and distribution of RES-E integration are not considered and will hence not be part of the additional costs of wind's intermittency to be calculated in the application. Following this discussion the analysis is based on whole Germany as the only considered region in the model.

3.2 Time horizon and discount rate

In order to estimate the dynamic effects of integrating large shares of RES-E in the German power system a time horizon until 2020 is considered. Thereby each year is sequentially modelled, i. e. a myoptic modelling approach is taken. A complete description of a year would generally result in an hourly time resolution resulting in 8760 time periods per year. This would lead to high computation times. To limit the computation time each year is divided in typical days and each day (weekday and weekend) in typical hours to take the differences in load and price patterns into account. To capture seasonal effects e. g. in electricity demand, wind availability and water inflow, separate typical days for every two months period are considered. With this for every two months one typical weekday (Monday to Friday) and weekend (Saturday and Sunday) exists, i. e. twelve typical days are taken into account. As the integration costs of RES-E highly depend on the temporal fluctuations in their supply the days are further divided in a two-hourly time resolution.

For an appropriate choice of the discount rate to account for endogenously modelled investments the various risks associated with power plant investments have to be analysed. Following Weber (2005) notably the following elements will influence the selection of an adequate discounting factor:

- market interest rate for risk free assets,
- credit risk associated with the investor,
- share of own capital required for the investment,
- technical, financial and other project risks,
- market price risks and finally
- market quantity risks.

These risks result in the uncertainty of the economic competitiveness of the power plant investment in the longer run. Notably price changes for fossil fuels may lead to a situation, where a new build power plant cannot recover the full operation margin required to refinance the investment. Price risks related to RES-E fluctuations are explicitly dealt with in the proposed model. However, fuel price risks will not directly be covered. Within the methodology developed here, they may roughly be approximated by an increase in the applicable discount rate. Therefore in the following (and as usual in the literature cf. e. g. Hoster, 1996; Schwarz, 2005) the discount rate is assumed to be 8 %.

3.3 Generation capacities and investments

All fundamental models depend on the representation of the power plant portfolio of the considered system. Often technologies are grouped in order to reduce the complexity and the amount of computational work to a level that can be handled by the tools available. Thus, within this paper the power plants in Germany are grouped according to the main fuel used and the vintage. The characteristics of the considered thermal power plant classes, i. e. efficiency, availability, specific start-up costs, other variable costs and fixed operation costs, are given in Table 1. It may be noted that in the case study full- and part-load efficiencies are distinguished. Thereby part-load efficiencies are approximated linearly with an efficiency at minimum plant output and a constant marginal efficiency for any increase between minimum and maximum output, cf. Eq. (2). Additionally may be noted that in the case study distinct availabilities for the two months time periods are assumed, with higher availabilities in the winter months than in the summer months.

One further important characteristic of the considered power plant classes are the costs of generation. They can generally be divided into fixed and variable generation costs. Fixed generation costs are in particular expenses on depreciation, taxes, personnel costs, administration, assurance and regular maintenance. Fixed generation costs need only be considered if modelling a long time horizon and if investments in new capacities are endogenously modelled. The main investment opportunities considered in the model are given in Table 2. Variable generation costs are expenses on fuel costs, supply and disposal of materials, operational maintenance, and deterioration of materials with the greatest part determined by the fuel costs. The latter depend on the fuel prices and the efficiency of the respective power plant class. The development of fuel prices over time is assumed to be static, i. e. independent of investments in new power plants, and given in Table 3.

Besides the thermal power plants focused on so far, hydroelectric power plants play a considerable role in the German power system. Thereby three classes have to be distinguished: run-of-river plants, hydro storage plants and hydro storage plants with pumping facilities (pumped storage plants). In difference to the thermal power plants the costs of generation do not play such a significant role for hydro power plants. In case of run-of-river plants no variable costs need to be considered. In case of hydro storage plants no real variable costs arise. However, opportunity costs arising from using the stored capacities now and not later may be interpreted as variable costs. These are determined endogenously in the chosen modelling approach. In case of pumped storage plants the costs for pumping are often interpreted to be variable costs. However, as in reality electricity prices are not know ex-ante the operator's unit-commitment will not depend on the criteria of past pumping costs, rather on the opportunity costs. The latter correspond to the minimum of future expected revenues and future expected pumping costs. The characteristics of the considered hydro power plant classes are given in Table 4.

The introduction of new RES-E, namely wind, is assumed not to be market-driven but rather to be the result of government aid and is hence an exogenous input to the model. In order to analyse the effects of an increasing fraction of wind serving demand on the German power system several wind capacity deployment scenarios are considered. Those are depicted in Figure 3. The electricity production due to the installed wind turbines is subject to a stochastic capacity factor that will be discussed in the following.

3.4 Electricity demand

In the model the electricity demand is required to be satisfied at all times. Thereby electricity demand may be assumed to be price inelastic and can hence exogenously be given. It can be understood as the sum of demand of all consumer groups in Germany that result to one value for each two-hour time period of each typical day as given in Figure 4. It may be noted that the electricity demand is also subject to stochastic variations that are partly linked to climatic variables and partly also to other, unobserved factors. However, such effects are currently not taken into account in order to focus on the effects of stochastic electricity market modelling only. The development over time can be handled by using predefined growth rates as given in Table 5. It is furthermore important to note that the assumed growth in electricity demand has great influence on the generation by conventional sources and thereby on investment decisions and wholesale prices.

3.5 Energy policy

To assess the effects of energy policies on the additional costs of wind integration trading of CO_2 allowances is assumed. In the European Union emissions trading started with 2005. Thereby the member states set limits on CO_2 emissions from energy-intensive companies by issuing allowances as to how much CO_2 these companies are allowed to emit, with the reductions below the limits to be tradable. Hence, CO_2 emissions have a price. Evidently, this price is not known ex-ante, thus assumptions of the future development are necessary. In the current version of the model the price of CO_2 allowances is exogenously given by static expectations, i. e. the allowances price does not endogenously change with increased wind integration. The future allowance costs are thus determined by adding the allowance price times a fuel specific emission factor to the respective fuel price. The CO_2 emission factors are given in Table 6 and the development of the CO_2 allowance price is given in Table 7. With the latter may be seen that a low and a high CO_2 allowance price scenario is considered in the case study. Next to emissions trading the current governmental decision for a nuclear phase-out in Germany is presumed (hence investments in nuclear power plants are not allowed in the model, cf. Table 2).

3.6 Stochastics

In the case study short-term fluctuations are of major importance. Therefore wind speed data have been combined with aggregated power curves, similar to the approach presented by Sontow (2000). This is done using weather data from ten weather stations that reflect the spatial distribution of wind power in Germany. The time series are used to determine clusters of days with similar wind energy production. Thereby summer, winter and intermediate days are distinguished and for each six hour period cluster analyses are carried out to identify a high, medium and low wind case as well as the corresponding probabilities of occurrence and transition. The cases (or nodes to remain in above's nomenclature of the stochastic modelling approach) give the capacity factor of wind energy production. Multiplied with the installed wind capacity this yields the actual wind generation, hence the capacity factor corresponds to the full-load hours of wind energy production. The capacity factor is assumed to remain constant over the time horizon (even though a high variability for the considered typical hours is represented) and is given with the respective probabilities of occurrence for the three wind cases in Figure 5. Note that a constant capacity factor over the time horizon is a strong assumption that neglects the possible higher full-load hours of wind with an increased share of off-shore wind energy production (the data applied result in full-load hours of about 1650 hrs only). Hence, the value of wind may be underestimated in case of higher fractions of wind serving demand.

4 Effects of stochastic modelling

In this section results of the German case study are presented. Thereby the focus is on the effects of stochastic electricity market modelling on additional intermittent wind integration costs compared to a simple deterministic approach. Additionally the effects of high versus low CO_2 allowance prices are discussed in order to assess the importance of the future development of the overall system on wind's integration costs. Note that the results presented need to be seen as preliminary as currently ongoing research may alter the given cost figures. However, the general effects of stochastic modelling are not expected to change significantly.

Figure 6 gives the yearly electricity production in the base case of installed wind capacities applying the stochastic model version. It may be seen that the electricity production increases due to the assumed increase in demand. The high CO_2 allowance price case, cf. Figure 6 (a), shows high investments in gas-fired power plants, while the low CO_2 allowance price case, cf. Figure 6 (b), shows high investments in coal-fired power plants. Thus the investment decisions are highly dominated by the considered CO_2 allowance price paths (and hence by energy policies) even without considering a substantial increase of wind energy production over time. Further analysis yields to the conclusion that in a system with high CO_2 allowance prices and therefore high investments in gas-fired power plants (by regard of a nuclear phase-out) the integration costs due to additional wind generation will be comparatively low. One important reason is the higher flexibility in the system. This flexibility is also obtained with low CO_2 allowance prices as may be seen by the investments in additional gas-fired power plants, cf. Figure 6 (b). These investments, however, are solely due to the higher share of intermittent wind generation in the system and hence add cost to the overall system operation. It may be noted that the share of wind in electricity production is relatively low in the base case especially if compared to the installed capacities as given in Figure 3. This is due to the high fluctuations in the generation and the fairly low full-load hours of about 1650 hrs (the effects of this simplification will be discussed in the following; in a future model version is intended to allocate off-shore wind generation a substantially higher capacity factor).

One of the major outputs of the model is the development of wholesale electricity prices over a time horizon until 2020 as given in Figure 7. In the model these prices correspond to the marginal generation costs and may hence be different from the spot market prices historically observed. Especially for the year 2001 the prices are relatively high compared to available prices on the spot market (at the German spot market prices in 2001 were on average about 24 €/MWh). The reason for this may on the one hand be that the German market was not fully developed in the first years of the time horizon and may therefore not reflect actual prices (the traded volume was less than 7 % of the total consumption). On the other hand the generation companies may have submitted bids below their marginal generation costs in order to achieve a sufficient market share. Notably, the operators, contrarily to the model, may at that time not have included the fixed operation costs (e. g. insurance premiums, staff wages) in the bidding prices. Of course, inaccuracies in the model data may also account for some of the observed deviations. Thereby especially the fuel prices for gas (being the marginal plant) and the characteristics of the considered power plant classes are of major importance. Additionally, may be noted that the model considers Germany only and transmission, e. g. between Germany and France, is neglected. Modelling such transmission possibilities can have great impact on the prices, especially if imports of relatively inexpensive nuclear power from France to Germany is accounted for.

In the long-run the observed prices increase in case of high CO_2 allowance prices, cf. Figure 7 (a), and level-out in case of low CO_2 allowance prices, cf. Figure 7 (b). It may be seen that stochastic modelling of wind generation does not alter the estimated price development in the considered cases. This is due to the relatively minor impact of additional wind generation on the marginal power plant in the system. This, however, has to be taken carefully as the chosen distinction of power plant classes underestimates the sharp increase of the merit order with increasing conventional capacity. Nevertheless, it is important to note that the value of the last unit produced from wind energy may change substantially as shown in the following.

Next to the marginal electricity price Figure 7 also gives the marginal value of wind. This value is calculated as a weighted average of the hourly electricity prices, taking the wind energy production as a weighting factor. It includes avoided fuel costs, increased start-up costs and reduced part-load-efficiencies. One may see that the marginal value of wind as estimated applying the stochastic model version is generally lower than estimated applying the deterministic model version. Note that in the latter wind generation can be seen to be a firm input and may hence simply be subtracted from demand. Whereas in the former wind is assumed to be a stochastic input that hence results in a lower value of wind. The development over time shows a relatively constant difference between the marginal electricity price and the value of wind, albeit in case of the stochastic model a slight decrease of the value can be seen. This decrease is due to the higher share of wind in the system. An additional wind turbine then reduces the marginal value of wind in the total system. This can be explained by the decreasing capacity credit with an increased share of wind in the system and increased costs for power systems reserve. It may also be seen that this effect is not accounted for in the deterministic model version. Hence, one important result of this study is that a simple deterministic model will systematically overestimate the value of wind.

The difference between the marginal electricity price and the value of wind can be interpreted as the system integration costs for wind. In this application these integration costs include the joint effects of increased balancing costs, increased part-load operation of conventional power plants, additional reserve capacities and modified investment strategies. The yearly integration costs considering a low and a high wind generation scenario, that respectively correspond to a fraction of 5 % and 25 % of wind serving demand in 2020, are given in Figure 8. It can be seen that the integration as estimated applying the stochastic model version are significantly higher compared to the results of the deterministic model version. Additionally may be seen that the integration costs change over the considered time horizon and hence greatly depend on the ability of the considered system to dynamically adapt to an increased share of wind generation. A comparison between the high and the low CO_2 allowance price case again highlights that energy policies can have a major influence on the integration costs. Hence, the cost figures discussed in the literature (cf. e. g. Auer et al., 2004; van Werven et al., 2005; Gül and Stenzel, 2005, and the references therein) need to be analysed with particular care as often the assumptions leading to the presented results are not sufficiently discussed.

Figure 9 gives the marginal electricity price and the marginal value of wind in an adapting system over a given fraction of wind serving demand. To consider the system adapting to an increased wind generation the results are given for 2020 only. This ensures that the endogenously modelled investments are taken into account. It can be seen that the increased fraction of wind serving demand has little influence on the marginal electricity price, especially if the deterministic model version is applied (cf. the discussion of the results given in Figure 7). However, the marginal value of wind can be seen to significantly decrease with the fraction of wind serving demand, with lower values if stochastic modelling is taken into account. It is important to note that the modell currently underestimates the value of wind in case of higher fractions of wind serving demand. This is due to the simplification of considering a constant capacity factor over the time horizon, i. e. the increasing full-load hours with an increased share of off-shore generation is not accounted for. This may explain the sharp decrease in the value of wind energy in case of fractions of wind serving demand higher than 20 %. Note that this simplification does not affect the observed differences between the results estimated applying the deterministic and the stochastic model version.

The difference between the marginal electricity price and the marginal value of wind, i. e. the costs of integrating wind in the German power system, is given in Figure 10. It may be seen that the integration costs greatly depend on the considered CO_2 allowance prices, the fraction of wind serving demand and the explicit consideration of stochastic effects. Thereby a lower CO_2 allowance price leads to a decreased value of wind energy in the system, a higher fraction of wind serving demand leads to an increased share of part-load operation of conventional power plants and the explicit consideration of stochastic effects leads to account for the intermittency of wind generation. All these effects finally result to comparatively higher integration costs that are underestimated in static, deterministic electricity market models often applied in the past to assess the additional costs of wind integration.

5 Conclusions

This paper provides a novel methodology to estimate the additional costs of intermittent RES-E integration based on a stochastic fundamental electricity market model. Thereby the stochastics of intermittent RES-E are incorporated by a recombining tree following a stochastic programming approach. The applicability of the proposed approach is shown with a German case study on large-scale wind integration. The results presented indicate that the value of intermittent resources is generally overestimated applying a static, deterministic model. Especially the decreasing capacity credit with increasing installed RES-E capacities can not sufficiently be modelled. The results highlight that next to the explicit consideration of stochastics a model applied to assess the additional costs of intermittent RES-E integration should be able to endogenously adapt to an increasing share of intermittent generation, i. e. endogenous investment decision need to be accounted for. The developed approach lends itself to multiple further developments, including notably the extension to further regions and inclusion of further technologies. But also the rules for deriving optimal investments may be developed further, contributing to getting even more realistic pictures of the market developments. Subject of currently ongoing research are an improved consideration of increasing capacity factors with higher shares of off-shore generation, the inclusion of CO_2 restrictions rather than exogenously given allowance prices and an improved representation of power systems reserve.

Acknowledgement

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Figures and Tables

Variables

TC	Total costs	OC	Operating costs
SC	Start-up costs	FC	Fix costs
Q	Production	L	Capacity
E	Transmission flow	H	Storage level
S	Stochastic stages	N	Nodes

Indices

t	Time step	u	Unit type
r	Region	0	Minimal
m	Marginal	new	New
old	Old	irr	Irreversible
rev	Reversible	res	Power reserve
pum	Pumping	cyc	Cycling
T	Final time step	n	Node
s	Stochastic Stage	stu	Start-up
onl	Online		

Parameters

d	Duration	f	Frequency
fp	Fuel price	hr	Heat rate
lf	Load factor	oc	Other variable costs
sc	Specific start-up costs	fc	Specific fix costs
a	Annuity factor	i	Interest rate
lt	Lifetime	D	Energy demand
W	Water interflow	η	Efficiency
ψ	Probability of occurrence	τ	Probability of transition
ρ	Availability		

Fig. 1. Symbols used in the model

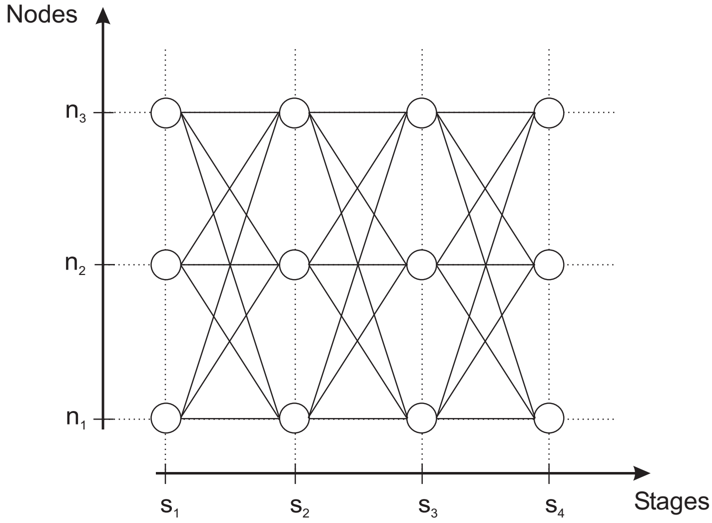
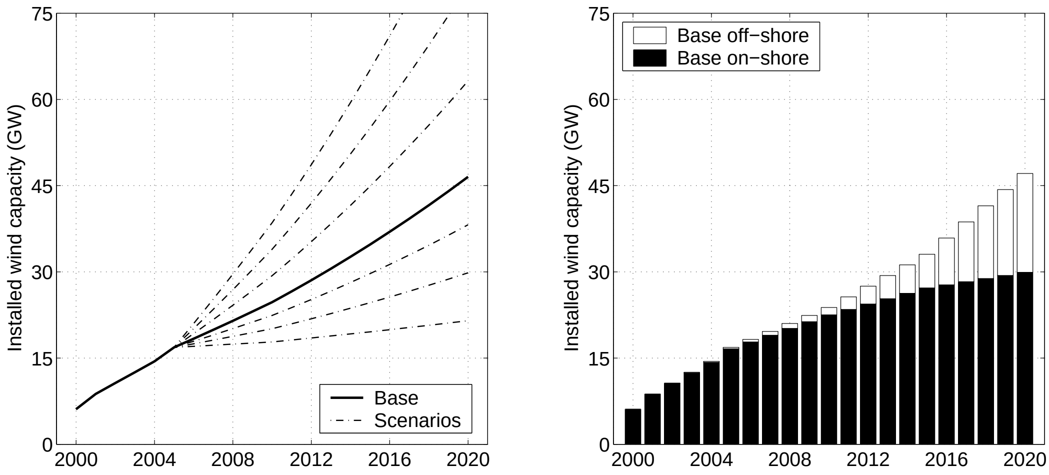


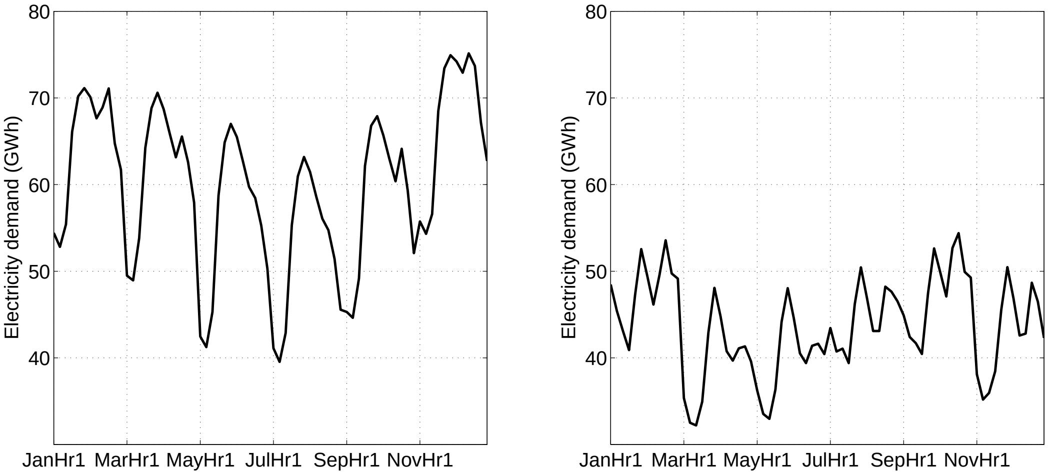
Fig. 2. Stochastic representation of RES-E's intermittency by a recombining tree



(a) Base case and scenarios

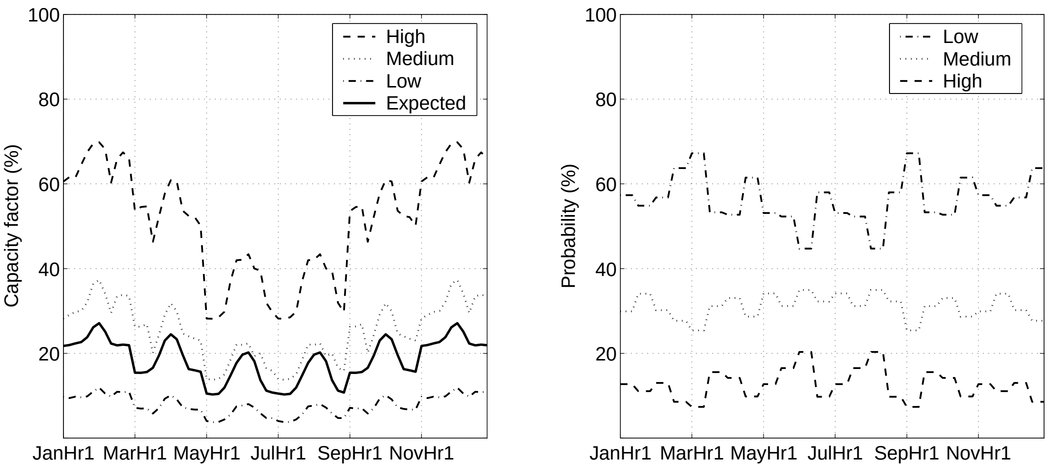
(b) Base case on- and off-shore

Fig. 3. Installed wind capacity



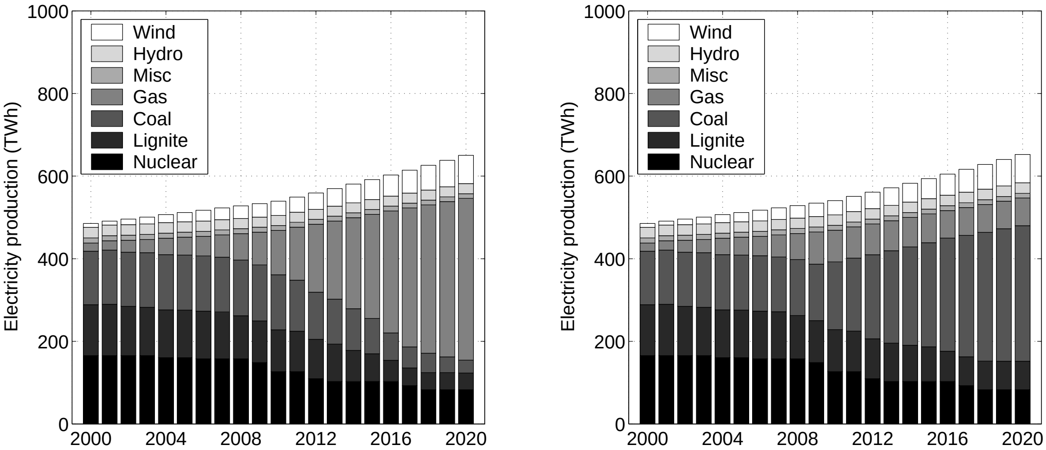
(a) Workdays (b) Weekends

Fig. 4. Electricity demand at typical hours



(a) Capacity factor (b) Probability

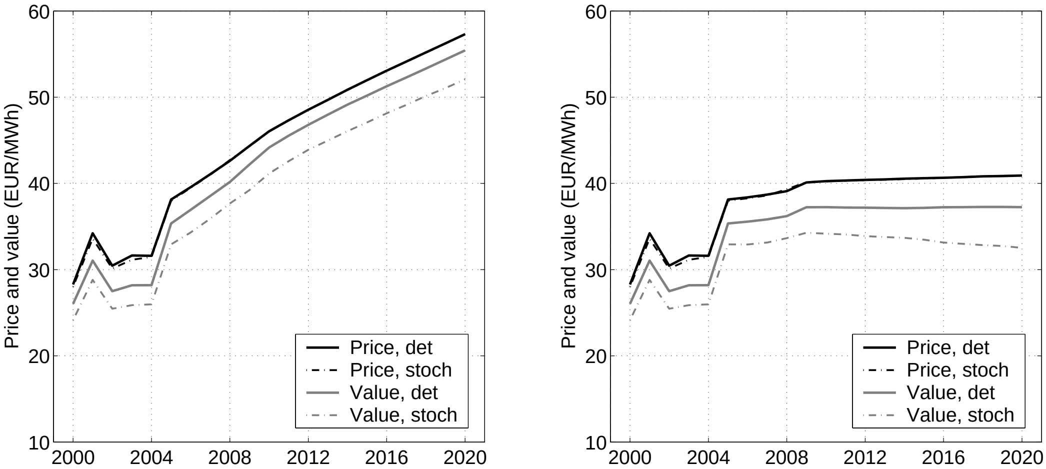
Fig. 5. Capacity factor of wind and corresponding node probability at typical hours



(a) High CO_2 allowance price

(b) Low CO_2 allowance price

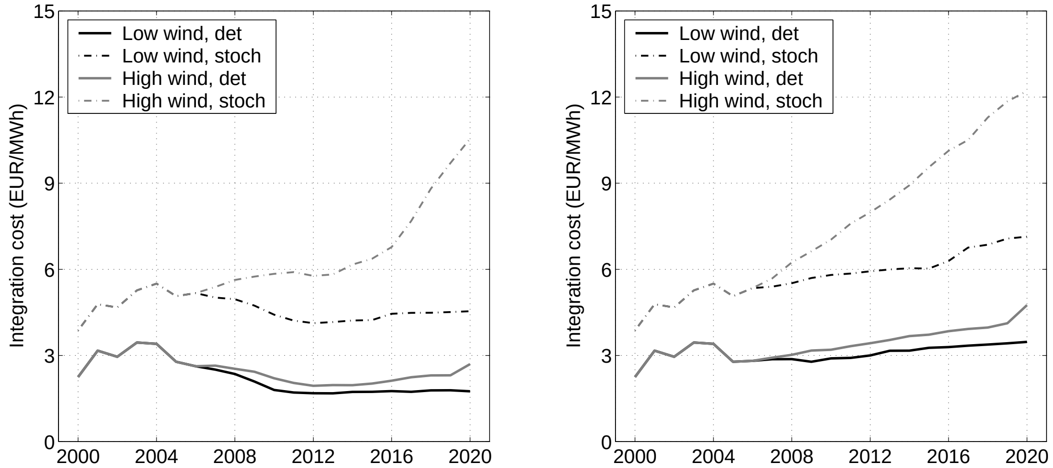
Fig. 6. Yearly electricity production (base case)



(a) High CO_2 allowance price

(b) Low CO_2 allowance price

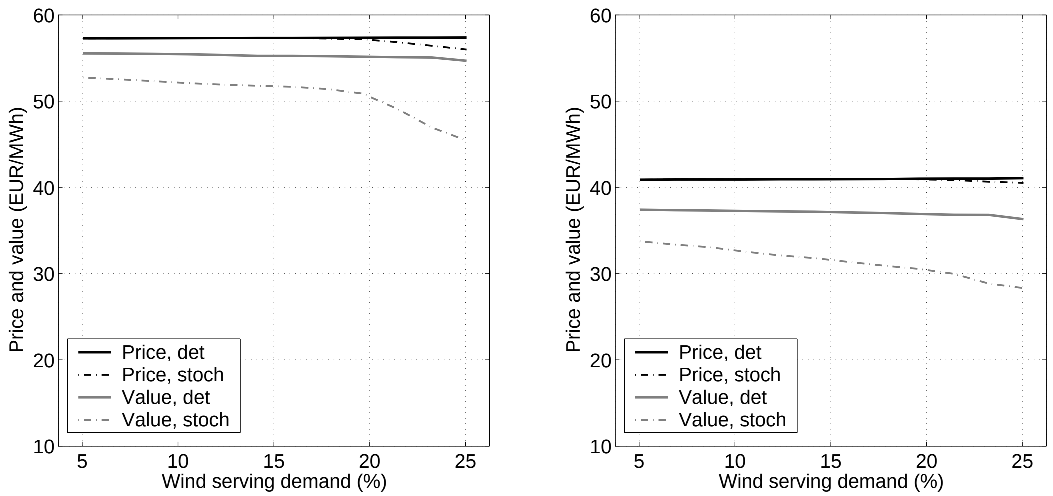
Fig. 7. Yearly marginal electricity price and marginal value of wind (base case)



(a) High CO_2 allowance price

(b) Low CO_2 allowance price

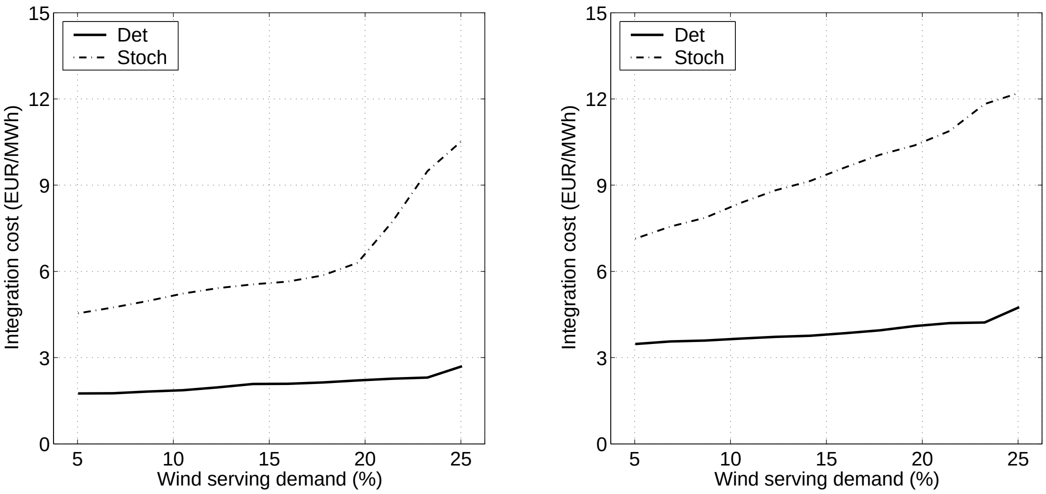
Fig. 8. Yearly integration cost of additional wind energy (low and high case)



(a) High CO_2 allowance price

(b) Low CO_2 allowance price

Fig. 9. Marginal electricity price and marginal value of wind in an adapting system over a given fraction of wind serving demand (in 2020)



(a) High CO_2 allowance price

(b) Low CO_2 allowance price

Fig. 10. Additional cost of integrating variable wind energy in an adapting system over a given fraction of wind serving demand (in 2020)

Table 1. Existing conventional thermal power plants

Type		CF-E-40	CF-E-44	LF-E-39	LF-E-45	GT-E-28	GF-E-43	NF-E-100	MF-E-42
Fuel type	(–)	Coal	Coal	Lignite	Lignite	Gas	Gas	Nuclear	Misc
Vintage	(–)	– 79	80 –	– 79	80 –	–	–	–	–
Overall capacity	(MW)	11924	13738	9084	7998	2290	16432	21181	1700
Efficiency (full load)	(%)	40	44	39	45	28	43	100	42
Availability (winter)	(%)	90	90	90	90	95	97	96	90
Specific start-up costs	(€/kW)	32	32	19	19	49	31	4	24
Other variable costs	(€/MWh)	2.2	2.2	1.7	1.7	1.2	1.2	0.5	1.2
Fixed operation costs	(€/kW)	43	43	52	52	19	19	38	19

Table 2
Investment opportunities in conventional thermal power plants

Type		CF-N-44	LF-N-45	GT-N-33	GF-N-58
Fuel	(–)	Coal	Lignite	Gas	Gas
Vintage	(–)	New	New	New	New
Net capacity	(MW)	750	750	146	750
Efficiency (full load)	(%)	44	45	33	58
Availability (winter)	(%)	92	92	95	97
Specific start-up costs	(€/kW)	32	19	49	30
Other variable costs	(€/MWh)	2.2	1.7	1.2	1.2
Fixed operation costs	(€/kW)	44	13	11	20
Investment costs	(€/kW)	1050	1350	230	450

Table 3
Fuel prices free plant (€/MWh)

	2000	2001	2002	2003	Yearly change (%)	2020
Coal	6.28	6.95	6.02	5.66	0.40	6.11
Lignite	3.55	3.59	3.62	3.66	0.40	3.95
Nuclear	6.14	6.14	6.14	6.14	0.00	6.14
Gas	14.54	18.68	15.87	16.65	1.10	19.97

Table 4
Existing hydro electric power plants

Type		RR-E	HS-E	PH-E
Fuel type	(–)	Water	Water	Water
Vintage	(–)	–	–	–
Overall capacity	(MW)	2421	324	5103
Availability	(%)	99	70	70
Other variable costs	(€/MWh)	2.5	2.5	2.5
Fixed operation costs	(€/kW)	69	25	25

Table 5
Gross electricity demand provided by public power plants (TWh)

	2000	Yearly change (%)	2010	Yearly change (%)	2020
Demand	486	1.1	541	0.8	649

Table 6
CO_2 emission factors (tCO_2/MWh)

	Factor
Coal	0.34
Lignite	0.40
Nuclear	0.00
Gas	0.20

Table 7
CO_2 allowance prices (€/tCO_2)

	2000 to 2004	2005	Yearly change	2020
Price constant scenario	0	10	0	10
Price increasing scenario	0	10	2	40